CASE NUMBER:

99-070

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

RECEIVED
SEP - 3 1999
PUBLIC SERVICE COMMISSION

IN THE MATTER OF)

RATE APPLICATION BY) Case No. 99-070

WESTERN KENTUCKY GAS COMPANY)

RESPONSE OF WESTERN KENTUCKY GAS COMPANY TO

ATTORNEY GENERAL DATA REQUEST DATED AUGUST 19, 1999

(AG DATA REQUEST NO. 1)

VOLUME 1 OF 3

SEPTEMBER 3, 1999

RECEIVED

SEP - 3 1999

PUBLIC SERVICE
COMMISSION

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1

KLEER-FAX RECYCLED 80000 SERIES 10% P.C.W.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 1
Witness: John P. Reddy

Data Request:

1. Provide the average daily amount of outstanding short-term debt for the fiscal years 1995, 1996, 1997, 1998 and 1999.

Response:

Please see attached worksheets for average daily short-term debt balances for fiscal years 1995 through June 30, 1999. [Note: Daily short-term debt balances do not include United Cities Gas Company short-term debt balances prior to September 1997 when UCG was acquired by Atmos.]

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: October 31, 1994

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Oct-94	58,000,000.00	3,000,000.00	55,000,000.00	8,847.32	267.12	404.38	8,710.06	5.78031%	7.75000%	11,678.08	267.12	11,945.20	7.92727%	01-Oct-94
02-Oct-94	58,000,000.00	3,000,000.00	55,000,000.00	8,847.32	267.12	404.38	8,710.06	5.78031%	7.75000%	11,678.08	267.12	11,945.20	7.92727%	02-Oct-94
03-Oct-94	43,900,000.00	0.00	43,900,000.00	6,167.77	267.12	0.00	6,434.89	5.35019%	7.75000%	9,321.23	267.12	9,588.35	7.97209%	03-Oct-94
04-Oct-94	44,300,000.00	0.00	44,300,000.00	6,157.94	267.12	0.00	6,425.06	5.29378%	7.75000%	9,406.16	267.12	9,673.28	7.97009%	04-Oct-94
05-Oct-94	43,000,000.00	0.00	43,000,000.00	5,917.77	267.12	0.00	6,184.89	5.24996%	7.75000%	9,130.14	267.12	9,397.26	7.97674%	05-Oct-94
06-Oct-94	40,200,000.00	0.00	40,200,000.00	5,591.60	267.12	0.00	5,858.72	5.31948%	7.75000%	8,535.62	267.12	8,802.74	7.99253%	06-Oct-94
07-Oct-94	39,400,000.00	0.00	39,400,000.00	5,508.65	267.12	0.00	5,775.77	5.35065%	7.75000%	8,365.75	267.12	8,632.87	7.99746%	07-Oct-94
08-Oct-94	39,400,000.00	0.00	39,400,000.00	5,508.65	267.12	0.00	5,775.77	5.35065%	7.75000%	8,365.75	267.12	8,632.87	7.99746%	08-Oct-94
09-Oct-94	39,400,000.00	0.00	39,400,000.00	5,508.65	267.12	0.00	5,775.77	5.35065%	7.75000%	8,365.75	267.12	8,632.87	7.99746%	09-Oct-94
10-Oct-94	39,400,000.00	0.00	39,400,000.00	5,508.65	267.12	0.00	5,775.77	5.35065%	7.75000%	8,365.75	267.12	8,632.87	7.99746%	10-Oct-94
11-Oct-94	35,300,000.00	0.00	35,300,000.00	4,900.81	267.12	0.00	5,167.93	5.34361%	7.75000%	7,495.21	267.12	7,762.32	8.02620%	11-Oct-94
12-Oct-94	33,100,000.00	0.00	33,100,000.00	4,536.88	267.12	0.00	4,804.00	5.29746%	7.75000%	7,028.08	267.12	7,295.20	8.04456%	12-Oct-94
13-Oct-94	29,700,000.00	0.00	29,700,000.00	4,061.06	267.12	0.00	4,328.18	5.31914%	7.75000%	6,306.16	267.12	6,573.28	8.07828%	13-Oct-94
14-Oct-94	30,600,000.00	0.00	30,600,000.00	4,137.66	267.12	0.00	4,404.78	5.25407%	7.75000%	6,497.26	267.12	6,764.38	8.06862%	14-Oct-94
15-Oct-94	30,600,000.00	0.00	30,600,000.00	4,137.66	267.12	0.00	4,404.78	5.25407%	7.75000%	6,497.26	267.12	6,764.38	8.06862%	15-Oct-94
16-Oct-94	30,600,000.00	0.00	30,600,000.00	4,137.66	267.12	0.00	4,404.78	5.25407%	7.75000%	6,497.26	267.12	6,764.38	8.06862%	16-Oct-94
17-Oct-94	30,400,000.00	0.00	30,400,000.00	4,212.27	267.12	0.00	4,479.39	5.37821%	7.75000%	6,454.79	267.12	6,721.91	8.07072%	17-Oct-94
18-Oct-94	30,600,000.00	0.00	30,600,000.00	4,208.41	267.12	0.00	4,475.53	5.33846%	7.75000%	6,497.26	267.12	6,764.38	8.06862%	18-Oct-94
19-Oct-94	29,600,000.00	0.00	29,600,000.00	4,030.59	267.12	0.00	4,297.71	5.29954%	7.75000%	6,284.93	267.12	6,552.05	8.07939%	19-Oct-94
20-Oct-94	29,500,000.00	0.00	29,500,000.00	4,025.38	267.12	0.00	4,292.50	5.31106%	7.75000%	6,263.70	267.12	6,530.82	8.08050%	20-Oct-94
21-Oct-94	32,000,000.00	0.00	32,000,000.00	4,342.20	267.12	0.00	4,609.32	5.25751%	7.75000%	6,794.52	267.12	7,061.64	8.05468%	21-Oct-94
22-Oct-94	32,000,000.00	0.00	32,000,000.00	4,342.20	267.12	0.00	4,609.32	5.25751%	7.75000%	6,794.52	267.12	7,061.64	8.05468%	22-Oct-94
23-Oct-94	32,000,000.00	0.00	32,000,000.00	4,342.20	267.12	0.00	4,609.32	5.25751%	7.75000%	6,794.52	267.12	7,061.64	8.05468%	23-Oct-94
24-Oct-94	32,200,000.00	0.00	32,200,000.00	4,407.49	267.12	0.00	4,674.61	5.29886%	7.75000%	6,836.99	267.12	7,104.11	8.05279%	24-Oct-94
25-Oct-94	32,600,000.00	0.00	32,600,000.00	4,459.21	267.12	0.00	4,726.33	5.29175%	7.75000%	6,921.92	267.12	7,189.04	8.04908%	25-Oct-94
26-Oct-94	32,500,000.00	0.00	32,500,000.00	4,462.65	267.12	0.00	4,729.77	5.31189%	7.75000%	6,900.68	267.12	7,167.80	8.05000%	26-Oct-94
27-Oct-94	32,400,000.00	0.00	32,400,000.00	4,467.69	267.12	0.00	4,734.81	5.33397%	7.75000%	6,879.45	267.12	7,146.57	8.05092%	27-Oct-94
28-Oct-94	32,300,000.00	0.00	32,300,000.00	4,464.67	267.12	0.00	4,731.79	5.34707%	7.75000%	6,858.22	267.12	7,125.34	8.05185%	28-Oct-94
29-Oct-94	32,300,000.00	0.00	32,300,000.00	4,464.67	267.12	0.00	4,731.79	5.34707%	7.75000%	6,858.22	267.12	7,125.34	8.05185%	29-Oct-94
30-Oct-94	32,300,000.00	0.00	32,300,000.00	4,464.67	267.12	0.00	4,731.79	5.34707%	7.75000%	6,858.22	267.12	7,125.34	8.05185%	30-Oct-94
31-Oct-94	37,200,000.00	0.00	37,200,000.00	5,255.27	267.12	0.00	5,522.39	5.41847%	7.75000%	7,898.63	267.12	8,165.75	8.01209%	31-Oct-94
				155,425.62	8,280.70	808.76	162,897.56			235,430.14	8,280.70	243,710.84		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)			
58,000,000.00		55,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
29,500,000.00		29,500,000.00	MINIMUM OUTSTANDING DURING MONTH		
35,961,290.32	193,548.39	35,767,741.94	MONTH-TO-DATE AVERAGE OUTSTANDING	35,767,741.94	
		162,897.56	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	243,710.84	
5.3600%	-4.9200%	5.3623%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.0226%	(5)
5.0888%		5.0898%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: November 30, 1994

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Nov-94	39,500,000.00	0.00	39,500,000.00	5,467.81	267.12	0.00	5,734.93	5.29937%	7.75000%	8,386.99	267.12	8,654.11	7.99683%	01-Nov-94
02-Nov-94	38,400,000.00	0.00	38,400,000.00	5,269.42	267.12	0.00	5,536.54	5.26260%	7.75000%	8,153.42	267.12	8,420.54	8.00390%	02-Nov-94
03-Nov-94	39,000,000.00	0.00	39,000,000.00	5,312.52	267.12	0.00	5,579.64	5.22197%	7.75000%	8,280.82	267.12	8,547.94	8.00000%	03-Nov-94
04-Nov-94	38,200,000.00	0.00	38,200,000.00	5,240.79	267.12	0.00	5,507.91	5.26279%	7.75000%	8,110.96	267.12	8,378.08	8.00523%	04-Nov-94
05-Nov-94	38,200,000.00	0.00	38,200,000.00	5,240.79	267.12	0.00	5,507.91	5.26279%	7.75000%	8,110.96	267.12	8,378.08	8.00523%	05-Nov-94
06-Nov-94	38,200,000.00	0.00	38,200,000.00	5,240.79	267.12	0.00	5,507.91	5.26279%	7.75000%	8,110.96	267.12	8,378.08	8.00523%	06-Nov-94
07-Nov-94	37,300,000.00	0.00	37,300,000.00	5,125.15	267.12	0.00	5,392.27	5.27662%	7.75000%	7,919.86	267.12	8,186.98	8.01139%	07-Nov-94
08-Nov-94	36,800,000.00	0.00	36,800,000.00	4,996.37	267.12	0.00	5,263.49	5.22058%	7.75000%	7,813.70	267.12	8,080.82	8.01494%	08-Nov-94
09-Nov-94	34,900,000.00	0.00	34,900,000.00	4,737.43	267.12	0.00	5,004.55	5.23398%	7.75000%	7,410.27	267.12	7,677.39	8.02937%	09-Nov-94
10-Nov-94	34,900,000.00	0.00	34,900,000.00	5,147.75	147.60	0.00	5,295.35	5.53812%	7.75000%	7,410.27	147.60	7,557.87	7.90437%	10-Nov-94
11-Nov-94	34,900,000.00	0.00	34,900,000.00	5,147.75	147.60	0.00	5,295.35	5.53812%	7.75000%	7,410.27	147.60	7,557.87	7.90437%	11-Nov-94
12-Nov-94	34,900,000.00	0.00	34,900,000.00	5,147.75	147.60	0.00	5,295.35	5.53812%	7.75000%	7,410.27	147.60	7,557.87	7.90437%	12-Nov-94
13-Nov-94	34,900,000.00	0.00	34,900,000.00	5,147.75	147.60	0.00	5,295.35	5.53812%	7.75000%	7,410.27	147.60	7,557.87	7.90437%	13-Nov-94
14-Nov-94	3,500,000.00	0.00	3,500,000.00	510.90	267.12	0.00	778.02	8.11363%	7.75000%	743.15	267.12	1,010.27	10.53567%	14-Nov-94
15-Nov-94	2,900,000.00	0.00	2,900,000.00	473.67	267.12	0.00	740.79	9.32373%	8.50000%	675.34	267.12	942.46	11.86202%	15-Nov-94
16-Nov-94	2,400,000.00	0.00	2,400,000.00	383.33	267.12	0.00	650.45	9.89225%	8.50000%	558.90	267.12	826.02	12.56244%	16-Nov-94
17-Nov-94	1,900,000.00	0.00	1,900,000.00	300.44	267.12	0.00	567.56	10.90312%	8.50000%	442.47	267.12	709.59	13.63151%	17-Nov-94
18-Nov-94	2,700,000.00	0.00	2,700,000.00	426.00	267.12	0.00	693.12	9.36995%	8.50000%	628.77	267.12	895.89	12.11106%	18-Nov-94
19-Nov-94	2,700,000.00	0.00	2,700,000.00	426.00	267.12	0.00	693.12	9.36995%	8.50000%	628.77	267.12	895.89	12.11106%	19-Nov-94
20-Nov-94	2,700,000.00	0.00	2,700,000.00	426.00	267.12	0.00	693.12	9.36995%	8.50000%	628.77	267.12	895.89	12.11106%	20-Nov-94
21-Nov-94	3,900,000.00	0.00	3,900,000.00	615.33	267.12	0.00	882.45	8.25882%	8.50000%	908.22	267.12	1,175.34	10.99996%	21-Nov-94
22-Nov-94	6,300,000.00	0.00	6,300,000.00	988.75	267.12	0.00	1,255.87	7.27607%	8.50000%	1,467.12	267.12	1,734.24	10.04760%	22-Nov-94
23-Nov-94	5,900,000.00	0.00	5,900,000.00	930.89	267.12	0.00	1,198.01	7.41141%	8.50000%	1,373.97	267.12	1,641.09	10.15252%	23-Nov-94
24-Nov-94	5,900,000.00	0.00	5,900,000.00	930.89	267.12	0.00	1,198.01	7.41141%	8.50000%	1,373.97	267.12	1,641.09	10.15252%	24-Nov-94
25-Nov-94	7,000,000.00	0.00	7,000,000.00	1,155.49	267.12	0.00	1,422.61	7.41789%	8.50000%	1,630.14	267.12	1,897.26	9.89284%	25-Nov-94
26-Nov-94	7,000,000.00	0.00	7,000,000.00	1,155.49	267.12	0.00	1,422.61	7.41789%	8.50000%	1,630.14	267.12	1,897.26	9.89284%	26-Nov-94
27-Nov-94	7,000,000.00	0.00	7,000,000.00	1,155.49	267.12	0.00	1,422.61	7.41789%	8.50000%	1,630.14	267.12	1,897.26	9.89284%	27-Nov-94
28-Nov-94	7,400,000.00	0.00	7,400,000.00	1,221.51	267.12	0.00	1,488.63	7.34256%	8.50000%	1,723.29	267.12	1,990.41	9.81755%	28-Nov-94
29-Nov-94	6,900,000.00	0.00	6,900,000.00	1,115.02	267.12	0.00	1,382.14	7.31132%	8.50000%	1,606.85	267.12	1,873.97	9.91302%	29-Nov-94
30-Nov-94	12,100,000.00	0.00	12,100,000.00	1,979.39	267.12	0.00	2,246.51	6.77666%	8.50000%	2,817.81	267.12	3,084.93	9.30577%	30-Nov-94
				81,416.66	7,535.50	0.00	88,952.16			122,406.85	7,535.50	129,942.35		

39,500,000.00		39,500,000.00	MAXIMUM OUTSTANDING DURING MONTH		
1,900,000.00		1,900,000.00	MINIMUM OUTSTANDING DURING MONTH		
18,943,333.33	0.00	18,943,333.33	MONTH-TO-DATE AVERAGE OUTSTANDING	18,943,333.33	
		88,952.16	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	129,942.35	
5.7131%	N.A.	5.7131%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.3458%	(5)
5.2291%		5.2291%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: December 31, 1994

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Dec-94	13,000,000.00	0.00	13,000,000.00	2,074.07	267.12	0.00	2,341.19	6.57334%	8.50000%	3,027.40	267.12	3,294.52	9.24999%	01-Dec-94
02-Dec-94	12,300,000.00	0.00	12,300,000.00	1,941.50	267.12	0.00	2,208.62	6.55403%	8.50000%	2,864.38	267.12	3,131.50	9.29267%	02-Dec-94
03-Dec-94	12,300,000.00	0.00	12,300,000.00	1,941.50	267.12	0.00	2,208.62	6.55403%	8.50000%	2,864.38	267.12	3,131.50	9.29267%	03-Dec-94
04-Dec-94	12,300,000.00	0.00	12,300,000.00	1,941.50	267.12	0.00	2,208.62	6.55403%	8.50000%	2,864.38	267.12	3,131.50	9.29267%	04-Dec-94
05-Dec-94	12,800,000.00	0.00	12,800,000.00	2,023.00	267.12	0.00	2,290.12	6.53042%	8.50000%	2,980.82	267.12	3,247.94	9.26171%	05-Dec-94
06-Dec-94	12,100,000.00	0.00	12,100,000.00	1,881.00	267.12	0.00	2,148.12	6.47986%	8.50000%	2,817.81	267.12	3,084.93	9.30577%	06-Dec-94
07-Dec-94	10,400,000.00	0.00	10,400,000.00	1,574.97	267.12	0.00	1,842.09	6.46503%	8.50000%	2,421.92	267.12	2,689.04	9.43749%	07-Dec-94
08-Dec-94	0.00	1,500,000.00	(1,500,000.00)	0.00	267.12	221.92	45.20	N.A.	8.50000%	0.00	267.12	45.20	N/A	08-Dec-94
09-Dec-94	0.00	200,000.00	(200,000.00)	0.00	267.12	29.59	237.53	N.A.	8.50000%	0.00	267.12	237.53	N/A	09-Dec-94
10-Dec-94	0.00	200,000.00	(200,000.00)	0.00	267.12	29.59	237.53	N.A.	8.50000%	0.00	267.12	237.53	N/A	10-Dec-94
11-Dec-94	0.00	200,000.00	(200,000.00)	0.00	267.12	29.59	237.53	N.A.	8.50000%	0.00	267.12	237.53	N/A	11-Dec-94
12-Dec-94	0.00	2,000,000.00	(2,000,000.00)	0.00	267.12	296.44	(29.32)	-0.53507%	8.50000%	0.00	267.12	(29.32)	N/A	12-Dec-94
13-Dec-94	0.00	2,300,000.00	(2,300,000.00)	0.00	267.12	342.16	(75.04)	-1.19093%	8.50000%	0.00	267.12	(75.04)	N/A	13-Dec-94
14-Dec-94	0.00	4,500,000.00	(4,500,000.00)	0.00	267.12	668.22	(401.10)	-3.25336%	8.50000%	0.00	267.12	(401.10)	N/A	14-Dec-94
15-Dec-94	0.00	5,600,000.00	(5,600,000.00)	0.00	267.12	845.37	(578.25)	-3.76895%	8.50000%	0.00	267.12	(578.25)	N/A	15-Dec-94
16-Dec-94	0.00	4,300,000.00	(4,300,000.00)	0.00	267.12	643.23	(376.11)	-3.19259%	8.50000%	0.00	267.12	(376.11)	N/A	16-Dec-94
17-Dec-94	0.00	4,300,000.00	(4,300,000.00)	0.00	267.12	643.23	(376.11)	-3.19257%	8.50000%	0.00	267.12	(376.11)	N/A	17-Dec-94
18-Dec-94	0.00	4,300,000.00	(4,300,000.00)	0.00	267.12	643.23	(376.11)	-3.19257%	8.50000%	0.00	267.12	(376.11)	N/A	18-Dec-94
19-Dec-94	0.00	5,800,000.00	(5,800,000.00)	0.00	267.12	867.62	(600.50)	-3.77899%	8.50000%	0.00	267.12	(600.50)	N/A	19-Dec-94
20-Dec-94	0.00	4,600,000.00	(4,600,000.00)	0.00	267.12	684.33	(417.21)	-3.31047%	8.50000%	0.00	267.12	(417.21)	N/A	20-Dec-94
21-Dec-94	0.00	6,600,000.00	(6,600,000.00)	0.00	267.12	1,003.56	(736.44)	-4.07275%	8.50000%	0.00	267.12	(736.44)	N/A	21-Dec-94
22-Dec-94	0.00	5,600,000.00	(5,600,000.00)	0.00	267.12	857.64	(590.52)	-3.84895%	8.50000%	0.00	267.12	(590.52)	N/A	22-Dec-94
23-Dec-94	0.00	5,200,000.00	(5,200,000.00)	0.00	267.12	793.53	(526.41)	-3.69503%	8.50000%	0.00	267.12	(526.41)	N/A	23-Dec-94
24-Dec-94	0.00	5,200,000.00	(5,200,000.00)	0.00	267.12	793.53	(526.41)	-3.69500%	8.50000%	0.00	267.12	(526.41)	N/A	24-Dec-94
25-Dec-94	0.00	5,200,000.00	(5,200,000.00)	0.00	267.12	793.53	(526.41)	-3.69500%	8.50000%	0.00	267.12	(526.41)	N/A	25-Dec-94
26-Dec-94	0.00	5,200,000.00	(5,200,000.00)	0.00	267.12	793.53	(526.41)	-3.69500%	8.50000%	0.00	267.12	(526.41)	N/A	26-Dec-94
27-Dec-94	0.00	4,400,000.00	(4,400,000.00)	0.00	267.12	676.27	(409.15)	-3.39412%	8.50000%	0.00	267.12	(409.15)	N/A	27-Dec-94
28-Dec-94	0.00	5,500,000.00	(5,500,000.00)	0.00	267.12	837.81	(570.69)	-3.78730%	8.50000%	0.00	267.12	(570.69)	N/A	28-Dec-94
29-Dec-94	0.00	8,300,000.00	(8,300,000.00)	0.00	267.12	1,280.25	(1,013.13)	-4.45532%	8.50000%	0.00	267.12	(1,013.13)	N/A	29-Dec-94
30-Dec-94	13,000,000.00	2,000,000.00	11,000,000.00	2,251.56	267.12	304.66	2,214.02	7.34653%	8.50000%	2,561.64	267.12	2,828.76	9.38635%	30-Dec-94
31-Dec-94	13,000,000.00	2,000,000.00	11,000,000.00	2,251.56	267.12	304.66	2,214.02	7.34652%	8.50000%	2,561.64	267.12	2,828.76	9.38635%	31-Dec-94
				17,880.66	8,280.70	14,383.49	11,777.87			24,964.38	8,280.70	19,470.91		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T.		NET INTEREST EXPENSE	
13,000,000.00		13,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(8,300,000.00)	MINIMUM OUTSTANDING DURING MONTH		
3,587,096.77	3,064,516.13	522,580.65	MONTH-TO-DATE AVERAGE OUTSTANDING	3,458,064.52	
		11,777.87	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	19,470.91	
8.5871%	-5.5263%	26.5366%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	6.6296%	(5)
5.8691%		7.8794%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: January 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jan-95	13,000,000.00	2,000,000.00	11,000,000.00	2,251.56	267.12	304.66	2,214.02	7.34652%	8.50000%	2,561.64	267.12	2,828.76	9.38635%	01-Jan-95
02-Jan-95	13,000,000.00	2,000,000.00	11,000,000.00	2,251.56	267.12	304.66	2,214.02	7.34652%	8.50000%	2,561.64	267.12	2,828.76	9.38635%	02-Jan-95
03-Jan-95	10,100,000.00	0.00	10,100,000.00	1,686.26	267.12	0.00	1,953.38	7.05924%	8.50000%	2,352.05	267.12	2,619.17	9.46533%	03-Jan-95
04-Jan-95	8,400,000.00	0.00	8,400,000.00	1,414.00	267.12	0.00	1,681.12	7.30486%	8.50000%	1,956.16	267.12	2,223.28	9.66070%	04-Jan-95
05-Jan-95	5,600,000.00	0.00	5,600,000.00	922.44	267.12	0.00	1,189.56	7.75338%	8.50000%	1,304.11	267.12	1,571.23	10.24105%	05-Jan-95
06-Jan-95	3,500,000.00	0.00	3,500,000.00	564.86	267.12	0.00	831.98	8.67636%	8.50000%	815.07	267.12	1,082.19	11.28567%	06-Jan-95
07-Jan-95	3,500,000.00	0.00	3,500,000.00	564.86	267.12	0.00	831.98	8.67636%	8.50000%	815.07	267.12	1,082.19	11.28567%	07-Jan-95
08-Jan-95	3,500,000.00	0.00	3,500,000.00	564.86	267.12	0.00	831.98	8.67636%	8.50000%	815.07	267.12	1,082.19	11.28567%	08-Jan-95
09-Jan-95	1,300,000.00	0.00	1,300,000.00	207.64	267.12	0.00	474.76	13.32978%	8.50000%	302.74	267.12	569.86	15.99989%	09-Jan-95
10-Jan-95	0.00	800,000.00	(800,000.00)	0.00	267.12	125.15	141.97	N.A.	8.50000%	0.00	267.12	141.97	N/A	10-Jan-95
11-Jan-95	0.00	3,600,000.00	(3,600,000.00)	0.00	267.12	557.26	(290.14)	-2.94171%	8.50000%	0.00	267.12	(290.14)	N/A	11-Jan-95
12-Jan-95	0.00	7,300,000.00	(7,300,000.00)	0.00	267.12	1,134.00	(866.88)	-4.33440%	8.50000%	0.00	267.12	(866.88)	N/A	12-Jan-95
13-Jan-95	0.00	7,000,000.00	(7,000,000.00)	0.00	267.12	1,102.74	(835.62)	-4.35716%	8.50000%	0.00	267.12	(835.62)	N/A	13-Jan-95
14-Jan-95	0.00	7,000,000.00	(7,000,000.00)	0.00	267.12	1,102.74	(835.62)	-4.35716%	8.50000%	0.00	267.12	(835.62)	N/A	14-Jan-95
15-Jan-95	0.00	7,000,000.00	(7,000,000.00)	0.00	267.12	1,102.74	(835.62)	-4.35716%	8.50000%	0.00	267.12	(835.62)	N/A	15-Jan-95
16-Jan-95	0.00	7,000,000.00	(7,000,000.00)	0.00	267.12	1,102.74	(835.62)	-4.35716%	8.50000%	0.00	267.12	(835.62)	N/A	16-Jan-95
17-Jan-95	0.00	8,800,000.00	(8,800,000.00)	0.00	267.12	1,403.18	(1,136.06)	-4.71206%	8.50000%	0.00	267.12	(1,136.06)	N/A	17-Jan-95
18-Jan-95	0.00	7,700,000.00	(7,700,000.00)	0.00	267.12	1,223.56	(956.44)	-4.53378%	8.50000%	0.00	267.12	(956.44)	N/A	18-Jan-95
19-Jan-95	0.00	9,900,000.00	(9,900,000.00)	0.00	267.12	1,540.60	(1,273.48)	-4.69517%	8.50000%	0.00	267.12	(1,273.48)	N/A	19-Jan-95
20-Jan-95	0.00	7,700,000.00	(7,700,000.00)	0.00	267.12	1,179.26	(912.14)	-4.32378%	8.50000%	0.00	267.12	(912.14)	N/A	20-Jan-95
21-Jan-95	0.00	7,700,000.00	(7,700,000.00)	0.00	267.12	1,179.26	(912.14)	-4.32378%	8.50000%	0.00	267.12	(912.14)	N/A	21-Jan-95
22-Jan-95	0.00	7,700,000.00	(7,700,000.00)	0.00	267.12	1,179.26	(912.14)	-4.32378%	8.50000%	0.00	267.12	(912.14)	N/A	22-Jan-95
23-Jan-95	0.00	7,500,000.00	(7,500,000.00)	0.00	267.12	1,158.90	(891.78)	-4.34002%	8.50000%	0.00	267.12	(891.78)	N/A	23-Jan-95
24-Jan-95	0.00	8,700,000.00	(8,700,000.00)	0.00	267.12	1,337.18	(1,070.06)	-4.48933%	8.50000%	0.00	267.12	(1,070.06)	N/A	24-Jan-95
25-Jan-95	0.00	7,100,000.00	(7,100,000.00)	0.00	267.12	1,093.21	(826.09)	-4.24678%	8.50000%	0.00	267.12	(826.09)	N/A	25-Jan-95
26-Jan-95	0.00	8,600,000.00	(8,600,000.00)	0.00	267.12	1,335.95	(1,068.83)	-4.53630%	8.50000%	0.00	267.12	(1,068.83)	N/A	26-Jan-95
27-Jan-95	0.00	7,600,000.00	(7,600,000.00)	0.00	267.12	1,193.10	(925.98)	-4.44712%	8.50000%	0.00	267.12	(925.98)	N/A	27-Jan-95
28-Jan-95	0.00	7,600,000.00	(7,600,000.00)	0.00	267.12	1,193.10	(925.98)	-4.44714%	8.50000%	0.00	267.12	(925.98)	N/A	28-Jan-95
29-Jan-95	0.00	7,600,000.00	(7,600,000.00)	0.00	267.12	1,193.10	(925.98)	-4.44714%	8.50000%	0.00	267.12	(925.98)	N/A	29-Jan-95
30-Jan-95	0.00	8,400,000.00	(8,400,000.00)	0.00	267.12	1,348.60	(1,081.48)	-4.69930%	8.50000%	0.00	267.12	(1,081.48)	N/A	30-Jan-95
31-Jan-95	7,000,000.00	0.00	7,000,000.00	1,191.94	267.12	0.00	1,459.06	7.60795%	8.50000%	1,630.14	267.12	1,897.26	9.89284%	31-Jan-95
				11,613.98	8,280.70	24,394.94	(4,494.26)			15,113.70	8,280.70	(391.22)		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
13,000,000.00		11,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(9,900,000.00)	MINIMUM OUTSTANDING DURING MONTH		
2,222,580.65	5,041,935.48	(2,819,354.84)	MONTH-TO-DATE AVERAGE OUTSTANDING	2,093,548.39	
		(4,494.26)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(391.22)	
10.5425%	-5.6968%	1.8769%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
6.1557%		5.3351%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: February 28, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O. INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Feb-95	5,400,000.00	0.00	5,400,000.00	927.00	267.12	0.00	1,194.12	8.07136%	9.00000%	1,331.51	267.12	1,598.63	10.80553%	01-Feb-95
02-Feb-95	3,600,000.00	0.00	3,600,000.00	618.00	267.12	0.00	885.12	8.97413%	9.00000%	887.67	267.12	1,154.79	11.70829%	02-Feb-95
03-Feb-95	2,400,000.00	0.00	2,400,000.00	408.00	267.12	0.00	675.12	10.26744%	9.00000%	591.78	267.12	858.90	13.06244%	03-Feb-95
04-Feb-95	2,400,000.00	0.00	2,400,000.00	408.00	267.12	0.00	675.12	10.26744%	9.00000%	591.78	267.12	858.90	13.06244%	04-Feb-95
05-Feb-95	2,400,000.00	0.00	2,400,000.00	408.00	267.12	0.00	675.12	10.26744%	9.00000%	591.78	267.12	858.90	13.06244%	05-Feb-95
06-Feb-95	0.00	0.00	0.00	0.00	267.12	0.00	267.12	N.A.	9.00000%	0.00	267.12	267.12	N/A	06-Feb-95
07-Feb-95	0.00	2,100,000.00	(2,100,000.00)	0.00	267.12	344.63	(77.51)	-1.34721%	9.00000%	0.00	267.12	(77.51)	N/A	07-Feb-95
08-Feb-95	0.00	6,300,000.00	(6,300,000.00)	0.00	267.12	1,035.62	(768.50)	-4.45240%	9.00000%	0.00	267.12	(768.50)	N/A	08-Feb-95
09-Feb-95	0.00	9,700,000.00	(9,700,000.00)	0.00	267.12	1,594.52	(1,327.40)	-4.99486%	9.00000%	0.00	267.12	(1,327.40)	N/A	09-Feb-95
10-Feb-95	0.00	12,000,000.00	(12,000,000.00)	0.00	267.12	1,969.32	(1,702.20)	-5.17751%	9.00000%	0.00	267.12	(1,702.20)	N/A	10-Feb-95
11-Feb-95	0.00	12,000,000.00	(12,000,000.00)	0.00	267.12	1,969.32	(1,702.20)	-5.17753%	9.00000%	0.00	267.12	(1,702.20)	N/A	11-Feb-95
12-Feb-95	0.00	12,000,000.00	(12,000,000.00)	0.00	267.12	1,969.32	(1,702.20)	-5.17753%	9.00000%	0.00	267.12	(1,702.20)	N/A	12-Feb-95
13-Feb-95	0.00	14,400,000.00	(14,400,000.00)	0.00	267.12	2,365.15	(2,098.03)	-5.31793%	9.00000%	0.00	267.12	(2,098.03)	N/A	13-Feb-95
14-Feb-95	0.00	16,100,000.00	(16,100,000.00)	0.00	267.12	2,646.49	(2,379.37)	-5.39423%	9.00000%	0.00	267.12	(2,379.37)	N/A	14-Feb-95
15-Feb-95	0.00	18,600,000.00	(18,600,000.00)	0.00	267.12	3,093.53	(2,826.41)	-5.54646%	9.00000%	0.00	267.12	(2,826.41)	N/A	15-Feb-95
16-Feb-95	0.00	20,100,000.00	(20,100,000.00)	0.00	267.12	3,301.81	(3,034.69)	-5.51075%	9.00000%	0.00	267.12	(3,034.69)	N/A	16-Feb-95
17-Feb-95	0.00	20,000,000.00	(20,000,000.00)	0.00	267.12	3,271.23	(3,004.11)	-5.48251%	9.00000%	0.00	267.12	(3,004.11)	N/A	17-Feb-95
18-Feb-95	0.00	20,000,000.00	(20,000,000.00)	0.00	267.12	3,271.23	(3,004.11)	-5.48250%	9.00000%	0.00	267.12	(3,004.11)	N/A	18-Feb-95
19-Feb-95	0.00	20,000,000.00	(20,000,000.00)	0.00	267.12	3,271.23	(3,004.11)	-5.48250%	9.00000%	0.00	267.12	(3,004.11)	N/A	19-Feb-95
20-Feb-95	0.00	20,000,000.00	(20,000,000.00)	0.00	267.12	3,271.23	(3,004.11)	-5.48250%	9.00000%	0.00	267.12	(3,004.11)	N/A	20-Feb-95
21-Feb-95	0.00	19,500,000.00	(19,500,000.00)	0.00	267.12	3,221.92	(2,954.80)	-5.53078%	9.00000%	0.00	267.12	(2,954.80)	N/A	21-Feb-95
22-Feb-95	0.00	19,800,000.00	(19,800,000.00)	0.00	267.12	3,267.12	(3,000.00)	-5.53031%	9.00000%	0.00	267.12	(3,000.00)	N/A	22-Feb-95
23-Feb-95	0.00	23,400,000.00	(23,400,000.00)	0.00	267.12	3,831.76	(3,564.64)	-5.56023%	9.00000%	0.00	267.12	(3,564.64)	N/A	23-Feb-95
24-Feb-95	0.00	22,000,000.00	(22,000,000.00)	0.00	267.12	3,594.52	(3,327.40)	-5.52046%	9.00000%	0.00	267.12	(3,327.40)	N/A	24-Feb-95
25-Feb-95	0.00	22,000,000.00	(22,000,000.00)	0.00	267.12	3,594.52	(3,327.40)	-5.52046%	9.00000%	0.00	267.12	(3,327.40)	N/A	25-Feb-95
26-Feb-95	0.00	22,000,000.00	(22,000,000.00)	0.00	267.12	3,594.52	(3,327.40)	-5.52046%	9.00000%	0.00	267.12	(3,327.40)	N/A	26-Feb-95
27-Feb-95	0.00	19,900,000.00	(19,900,000.00)	0.00	267.12	3,293.21	(3,026.09)	-5.55036%	9.00000%	0.00	267.12	(3,026.09)	N/A	27-Feb-95
28-Feb-95	0.00	3,700,000.00	(3,700,000.00)	0.00	267.12	624.44	(357.32)	-3.52490%	9.00000%	0.00	267.12	(357.32)	N/A	28-Feb-95
				2,769.00	7,479.34	58,396.64	(48,148.29)			3,994.52	7,479.34	(46,922.77)		

5,400,000.00		5,400,000.00	MAXIMUM OUTSTANDING DURING MONTH	
0.00		(23,400,000.00)	MINIMUM OUTSTANDING DURING MONTH	
578,571.43	12,700,000.00	(12,121,428.57)	MONTH-TO-DATE AVERAGE OUTSTANDING	578,571.43
		(48,148.29)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(46,922.77)
23.0904%	-5.9940%	5.1780%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A (5)
6.2388%		5.9823%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: March 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Mar-95	0.00	4,100,000.00	(4,100,000.00)	0.00	267.12	684.08	(416.96)	-3.71199%	9.00000%	0.00	267.12	(416.96)	N/A	01-Mar-95
02-Mar-95	0.00	6,800,000.00	(6,800,000.00)	0.00	267.12	1,125.26	(858.14)	-4.60620%	9.00000%	0.00	267.12	(858.14)	N/A	02-Mar-95
03-Mar-95	0.00	8,000,000.00	(8,000,000.00)	0.00	267.12	1,321.64	(1,054.52)	-4.81127%	9.00000%	0.00	267.12	(1,054.52)	N/A	03-Mar-95
04-Mar-95	0.00	8,000,000.00	(8,000,000.00)	0.00	267.12	1,321.64	(1,054.52)	-4.81125%	9.00000%	0.00	267.12	(1,054.52)	N/A	04-Mar-95
05-Mar-95	0.00	8,000,000.00	(8,000,000.00)	0.00	267.12	1,321.64	(1,054.52)	-4.81125%	9.00000%	0.00	267.12	(1,054.52)	N/A	05-Mar-95
06-Mar-95	0.00	10,400,000.00	(10,400,000.00)	0.00	267.12	1,729.53	(1,462.41)	-5.13251%	9.00000%	0.00	267.12	(1,462.41)	N/A	06-Mar-95
07-Mar-95	0.00	13,000,000.00	(13,000,000.00)	0.00	267.12	2,155.34	(1,888.22)	-5.30155%	9.00000%	0.00	267.12	(1,888.22)	N/A	07-Mar-95
08-Mar-95	0.00	16,700,000.00	(16,700,000.00)	0.00	267.12	2,757.21	(2,490.09)	-5.44240%	9.00000%	0.00	267.12	(2,490.09)	N/A	08-Mar-95
09-Mar-95	0.00	17,200,000.00	(17,200,000.00)	0.00	267.12	2,837.15	(2,570.03)	-5.45385%	9.00000%	0.00	267.12	(2,570.03)	N/A	09-Mar-95
10-Mar-95	0.00	19,200,000.00	(19,200,000.00)	0.00	267.12	3,160.77	(2,893.65)	-5.50094%	9.00000%	0.00	267.12	(2,893.65)	N/A	10-Mar-95
11-Mar-95	0.00	19,200,000.00	(19,200,000.00)	0.00	267.12	3,160.77	(2,893.65)	-5.50095%	9.00000%	0.00	267.12	(2,893.65)	N/A	11-Mar-95
12-Mar-95	0.00	19,200,000.00	(19,200,000.00)	0.00	267.12	3,160.77	(2,893.65)	-5.50095%	9.00000%	0.00	267.12	(2,893.65)	N/A	12-Mar-95
13-Mar-95	0.00	22,100,000.00	(22,100,000.00)	0.00	267.12	3,648.36	(3,381.24)	-5.58440%	9.00000%	0.00	267.12	(3,381.24)	N/A	13-Mar-95
14-Mar-95	0.00	23,800,000.00	(23,800,000.00)	0.00	267.12	3,920.82	(3,653.70)	-5.60337%	9.00000%	0.00	267.12	(3,653.70)	N/A	14-Mar-95
15-Mar-95	0.00	27,900,000.00	(27,900,000.00)	0.00	267.12	4,639.75	(4,372.63)	-5.72047%	9.00000%	0.00	267.12	(4,372.63)	N/A	15-Mar-95
16-Mar-95	0.00	26,200,000.00	(26,200,000.00)	0.00	267.12	4,337.10	(4,069.98)	-5.67001%	9.00000%	0.00	267.12	(4,069.98)	N/A	16-Mar-95
17-Mar-95	0.00	25,800,000.00	(25,800,000.00)	0.00	267.12	4,257.04	(3,989.92)	-5.64466%	9.00000%	0.00	267.12	(3,989.92)	N/A	17-Mar-95
18-Mar-95	0.00	25,800,000.00	(25,800,000.00)	0.00	267.12	4,257.04	(3,989.92)	-5.64466%	9.00000%	0.00	267.12	(3,989.92)	N/A	18-Mar-95
19-Mar-95	0.00	25,800,000.00	(25,800,000.00)	0.00	267.12	4,257.04	(3,989.92)	-5.64466%	9.00000%	0.00	267.12	(3,989.92)	N/A	19-Mar-95
20-Mar-95	0.00	26,500,000.00	(26,500,000.00)	0.00	267.12	4,386.16	(4,119.04)	-5.67340%	9.00000%	0.00	267.12	(4,119.04)	N/A	20-Mar-95
21-Mar-95	0.00	26,900,000.00	(26,900,000.00)	0.00	267.12	4,454.33	(4,187.21)	-5.68153%	9.00000%	0.00	267.12	(4,187.21)	N/A	21-Mar-95
22-Mar-95	0.00	26,900,000.00	(26,900,000.00)	0.00	267.12	4,446.96	(4,179.84)	-5.67153%	9.00000%	0.00	267.12	(4,179.84)	N/A	22-Mar-95
23-Mar-95	0.00	18,800,000.00	(18,800,000.00)	0.00	267.12	3,124.82	(2,857.70)	-5.54820%	9.00000%	0.00	267.12	(2,857.70)	N/A	23-Mar-95
24-Mar-95	0.00	15,500,000.00	(15,500,000.00)	0.00	267.12	2,580.96	(2,313.84)	-5.44872%	9.00000%	0.00	267.12	(2,313.84)	N/A	24-Mar-95
25-Mar-95	0.00	15,500,000.00	(15,500,000.00)	0.00	267.12	2,580.96	(2,313.84)	-5.44872%	9.00000%	0.00	267.12	(2,313.84)	N/A	25-Mar-95
26-Mar-95	0.00	15,500,000.00	(15,500,000.00)	0.00	267.12	2,580.96	(2,313.84)	-5.44872%	9.00000%	0.00	267.12	(2,313.84)	N/A	26-Mar-95
27-Mar-95	0.00	16,100,000.00	(16,100,000.00)	0.00	267.12	2,691.81	(2,424.69)	-5.49697%	9.00000%	0.00	267.12	(2,424.69)	N/A	27-Mar-95
28-Mar-95	0.00	17,000,000.00	(17,000,000.00)	0.00	267.12	2,852.33	(2,585.21)	-5.55060%	9.00000%	0.00	267.12	(2,585.21)	N/A	28-Mar-95
29-Mar-95	0.00	19,300,000.00	(19,300,000.00)	0.00	267.12	3,243.51	(2,976.39)	-5.62892%	9.00000%	0.00	267.12	(2,976.39)	N/A	29-Mar-95
30-Mar-95	0.00	20,400,000.00	(20,400,000.00)	0.00	267.12	3,420.55	(3,153.43)	-5.64216%	9.00000%	0.00	267.12	(3,153.43)	N/A	30-Mar-95
31-Mar-95	0.00	6,000,000.00	(6,000,000.00)	0.00	267.12	1,040.55	(773.43)	-4.70502%	9.00000%	0.00	267.12	(773.43)	N/A	31-Mar-95
				0.00	8,280.70	91,456.85	(83,176.14)			0.00	8,280.70	(83,176.14)		

0.00		(4,100,000.00)	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(27,900,000.00)	MINIMUM OUTSTANDING DURING MONTH		
0.00	17,793,548.39	(17,793,548.39)	MONTH-TO-DATE AVERAGE OUTSTANDING	0.00	
		(83,176.14)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(83,176.14)	
N.A.	-6.0518%	5.5039%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
N.A.		6.0518%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: April 30, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Apr-95	0.00	6,000,000.00	(6,000,000.00)	0.00	256.85	1,040.55	(783.70)	-4.76750%	9.00000%	0.00	256.85	(783.70)	N/A	01-Apr-95
02-Apr-95	0.00	6,000,000.00	(6,000,000.00)	0.00	256.85	1,040.55	(783.70)	-4.76750%	9.00000%	0.00	256.85	(783.70)	N/A	02-Apr-95
03-Apr-95	0.00	7,400,000.00	(7,400,000.00)	0.00	256.85	1,236.71	(979.86)	-4.83311%	9.00000%	0.00	256.85	(979.86)	N/A	03-Apr-95
04-Apr-95	0.00	8,600,000.00	(8,600,000.00)	0.00	256.85	1,437.26	(1,180.41)	-5.00988%	9.00000%	0.00	256.85	(1,180.41)	N/A	04-Apr-95
05-Apr-95	0.00	10,400,000.00	(10,400,000.00)	0.00	256.85	1,735.23	(1,478.38)	-5.18856%	9.00000%	0.00	256.85	(1,478.38)	N/A	05-Apr-95
06-Apr-95	0.00	12,900,000.00	(12,900,000.00)	0.00	256.85	2,152.36	(1,895.51)	-5.36326%	9.00000%	0.00	256.85	(1,895.51)	N/A	06-Apr-95
07-Apr-95	0.00	15,200,000.00	(15,200,000.00)	0.00	256.85	2,530.19	(2,273.34)	-5.45901%	9.00000%	0.00	256.85	(2,273.34)	N/A	07-Apr-95
08-Apr-95	0.00	15,200,000.00	(15,200,000.00)	0.00	256.85	2,530.19	(2,273.34)	-5.45901%	9.00000%	0.00	256.85	(2,273.34)	N/A	08-Apr-95
09-Apr-95	0.00	15,200,000.00	(15,200,000.00)	0.00	256.85	2,530.19	(2,273.34)	-5.45901%	9.00000%	0.00	256.85	(2,273.34)	N/A	09-Apr-95
10-Apr-95	0.00	17,200,000.00	(17,200,000.00)	0.00	256.85	2,867.89	(2,611.04)	-5.54087%	9.00000%	0.00	256.85	(2,611.04)	N/A	10-Apr-95
11-Apr-95	0.00	19,400,000.00	(19,400,000.00)	0.00	256.85	3,223.56	(2,966.71)	-5.58170%	9.00000%	0.00	256.85	(2,966.71)	N/A	11-Apr-95
12-Apr-95	0.00	22,400,000.00	(22,400,000.00)	0.00	256.85	3,713.42	(3,456.58)	-5.63237%	9.00000%	0.00	256.85	(3,456.58)	N/A	12-Apr-95
13-Apr-95	0.00	22,400,000.00	(22,400,000.00)	0.00	256.85	3,714.90	(3,458.05)	-5.63478%	9.00000%	0.00	256.85	(3,458.05)	N/A	13-Apr-95
14-Apr-95	0.00	21,600,000.00	(21,600,000.00)	0.00	256.85	3,589.70	(3,332.85)	-5.63190%	9.00000%	0.00	256.85	(3,332.85)	N/A	14-Apr-95
15-Apr-95	0.00	21,600,000.00	(21,600,000.00)	0.00	256.85	3,589.70	(3,332.85)	-5.63190%	9.00000%	0.00	256.85	(3,332.85)	N/A	15-Apr-95
16-Apr-95	0.00	21,600,000.00	(21,600,000.00)	0.00	256.85	3,589.70	(3,332.85)	-5.63190%	9.00000%	0.00	256.85	(3,332.85)	N/A	16-Apr-95
17-Apr-95	0.00	21,700,000.00	(21,700,000.00)	0.00	256.85	3,627.75	(3,370.90)	-5.66995%	9.00000%	0.00	256.85	(3,370.90)	N/A	17-Apr-95
18-Apr-95	0.00	22,700,000.00	(22,700,000.00)	0.00	256.85	3,783.12	(3,526.27)	-5.67000%	9.00000%	0.00	256.85	(3,526.27)	N/A	18-Apr-95
19-Apr-95	0.00	25,800,000.00	(25,800,000.00)	0.00	256.85	4,263.07	(4,006.22)	-5.66771%	9.00000%	0.00	256.85	(4,006.22)	N/A	19-Apr-95
20-Apr-95	0.00	25,800,000.00	(25,800,000.00)	0.00	256.85	4,264.60	(4,007.75)	-5.66988%	9.00000%	0.00	256.85	(4,007.75)	N/A	20-Apr-95
21-Apr-95	0.00	25,300,000.00	(25,300,000.00)	0.00	256.85	4,174.99	(3,918.14)	-5.65265%	9.00000%	0.00	256.85	(3,918.14)	N/A	21-Apr-95
22-Apr-95	0.00	25,300,000.00	(25,300,000.00)	0.00	256.85	4,174.99	(3,918.14)	-5.65265%	9.00000%	0.00	256.85	(3,918.14)	N/A	22-Apr-95
23-Apr-95	0.00	25,300,000.00	(25,300,000.00)	0.00	256.85	4,174.99	(3,918.14)	-5.65265%	9.00000%	0.00	256.85	(3,918.14)	N/A	23-Apr-95
24-Apr-95	0.00	24,300,000.00	(24,300,000.00)	0.00	256.85	4,021.04	(3,764.19)	-5.65403%	9.00000%	0.00	256.85	(3,764.19)	N/A	24-Apr-95
25-Apr-95	0.00	20,800,000.00	(20,800,000.00)	0.00	256.85	3,439.01	(3,182.16)	-5.58409%	9.00000%	0.00	256.85	(3,182.16)	N/A	25-Apr-95
26-Apr-95	0.00	22,700,000.00	(22,700,000.00)	0.00	256.85	3,778.27	(3,521.42)	-5.66220%	9.00000%	0.00	256.85	(3,521.42)	N/A	26-Apr-95
27-Apr-95	0.00	22,400,000.00	(22,400,000.00)	0.00	256.85	3,723.56	(3,466.71)	-5.64888%	9.00000%	0.00	256.85	(3,466.71)	N/A	27-Apr-95
28-Apr-95	0.00	5,500,000.00	(5,500,000.00)	0.00	256.85	916.16	(659.31)	-4.37545%	9.00000%	0.00	256.85	(659.31)	N/A	28-Apr-95
29-Apr-95	0.00	5,500,000.00	(5,500,000.00)	0.00	256.85	916.16	(659.31)	-4.37542%	9.00000%	0.00	256.85	(659.31)	N/A	29-Apr-95
30-Apr-95	0.00	5,500,000.00	(5,500,000.00)	0.00	256.85	916.16	(659.31)	-4.37542%	9.00000%	0.00	256.85	(659.31)	N/A	30-Apr-95
				0.00	7,705.48	86,696.00	(78,990.51)			0.00	7,705.48	(78,990.51)		

	0.00		(5,500,000.00)	MAXIMUM OUTSTANDING DURING MONTH		
	0.00		(25,800,000.00)	MINIMUM OUTSTANDING DURING MONTH		
	0.00	17,390,000.00	(17,390,000.00)	MONTH-TO-DATE AVERAGE OUTSTANDING	0.00	
			(78,990.51)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(78,990.51)	
	N.A.	-6.0656%	5.5265%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
	N.A.		6.0656%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: May 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O. INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-May-95	0.00	100,000.00	(100,000.00)	0.00	256.85	16.63	240.22	N.A.	9.00000%	0.00	256.85	240.22	N/A	01-May-95
02-May-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	9.00000%	0.00	256.85	256.85	N/A	02-May-95
03-May-95	0.00	1,700,000.00	(1,700,000.00)	0.00	256.85	282.71	(25.86)	-0.55529%	9.00000%	0.00	256.85	(25.86)	N/A	03-May-95
04-May-95	0.00	3,600,000.00	(3,600,000.00)	0.00	256.85	598.68	(341.84)	-3.46583%	9.00000%	0.00	256.85	(341.84)	N/A	04-May-95
05-May-95	0.00	4,700,000.00	(4,700,000.00)	0.00	256.85	781.62	(524.77)	-4.07532%	9.00000%	0.00	256.85	(524.77)	N/A	05-May-95
06-May-95	0.00	4,700,000.00	(4,700,000.00)	0.00	256.85	781.62	(524.77)	-4.07535%	9.00000%	0.00	256.85	(524.77)	N/A	06-May-95
07-May-95	0.00	4,700,000.00	(4,700,000.00)	0.00	256.85	781.62	(524.77)	-4.07535%	9.00000%	0.00	256.85	(524.77)	N/A	07-May-95
08-May-95	0.00	6,400,000.00	(6,400,000.00)	0.00	256.85	1,066.08	(809.23)	-4.61516%	9.00000%	0.00	256.85	(809.23)	N/A	08-May-95
09-May-95	0.00	8,700,000.00	(8,700,000.00)	0.00	256.85	1,444.44	(1,187.59)	-4.98241%	9.00000%	0.00	256.85	(1,187.59)	N/A	09-May-95
10-May-95	0.00	11,000,000.00	(11,000,000.00)	0.00	256.85	1,832.33	(1,575.48)	-5.22773%	9.00000%	0.00	256.85	(1,575.48)	N/A	10-May-95
11-May-95	0.00	12,000,000.00	(12,000,000.00)	0.00	256.85	1,995.62	(1,738.77)	-5.28875%	9.00000%	0.00	256.85	(1,738.77)	N/A	11-May-95
12-May-95	0.00	15,400,000.00	(15,400,000.00)	0.00	256.85	2,554.03	(2,297.18)	-5.44461%	9.00000%	0.00	256.85	(2,297.18)	N/A	12-May-95
13-May-95	0.00	15,400,000.00	(15,400,000.00)	0.00	256.85	2,554.03	(2,297.18)	-5.44462%	9.00000%	0.00	256.85	(2,297.18)	N/A	13-May-95
14-May-95	0.00	15,400,000.00	(15,400,000.00)	0.00	256.85	2,554.03	(2,297.18)	-5.44462%	9.00000%	0.00	256.85	(2,297.18)	N/A	14-May-95
15-May-95	0.00	16,600,000.00	(16,600,000.00)	0.00	256.85	2,766.41	(2,509.56)	-5.51801%	9.00000%	0.00	256.85	(2,509.56)	N/A	15-May-95
16-May-95	0.00	15,800,000.00	(15,800,000.00)	0.00	256.85	2,626.36	(2,369.51)	-5.47386%	9.00000%	0.00	256.85	(2,369.51)	N/A	16-May-95
17-May-95	0.00	17,200,000.00	(17,200,000.00)	0.00	256.85	2,851.84	(2,594.99)	-5.50680%	9.00000%	0.00	256.85	(2,594.99)	N/A	17-May-95
18-May-95	0.00	19,000,000.00	(19,000,000.00)	0.00	256.85	3,141.37	(2,884.52)	-5.54132%	9.00000%	0.00	256.85	(2,884.52)	N/A	18-May-95
19-May-95	0.00	17,600,000.00	(17,600,000.00)	0.00	256.85	2,904.05	(2,647.21)	-5.48994%	9.00000%	0.00	256.85	(2,647.21)	N/A	19-May-95
20-May-95	0.00	17,600,000.00	(17,600,000.00)	0.00	256.85	2,904.05	(2,647.20)	-5.48993%	9.00000%	0.00	256.85	(2,647.20)	N/A	20-May-95
21-May-95	0.00	17,600,000.00	(17,600,000.00)	0.00	256.85	2,904.05	(2,647.20)	-5.48993%	9.00000%	0.00	256.85	(2,647.20)	N/A	21-May-95
22-May-95	0.00	14,600,000.00	(14,600,000.00)	0.00	256.85	2,416.71	(2,159.86)	-5.39966%	9.00000%	0.00	256.85	(2,159.86)	N/A	22-May-95
23-May-95	0.00	15,000,000.00	(15,000,000.00)	0.00	256.85	2,475.62	(2,218.77)	-5.39900%	9.00000%	0.00	256.85	(2,218.77)	N/A	23-May-95
24-May-95	0.00	16,600,000.00	(16,600,000.00)	0.00	256.85	2,748.71	(2,491.86)	-5.47910%	9.00000%	0.00	256.85	(2,491.86)	N/A	24-May-95
25-May-95	0.00	13,900,000.00	(13,900,000.00)	0.00	256.85	2,301.21	(2,044.36)	-5.36827%	9.00000%	0.00	256.85	(2,044.36)	N/A	25-May-95
26-May-95	0.00	14,800,000.00	(14,800,000.00)	0.00	256.85	2,446.58	(2,189.73)	-5.40034%	9.00000%	0.00	256.85	(2,189.73)	N/A	26-May-95
27-May-95	0.00	14,800,000.00	(14,800,000.00)	0.00	256.85	2,446.58	(2,189.73)	-5.40035%	9.00000%	0.00	256.85	(2,189.73)	N/A	27-May-95
28-May-95	0.00	14,800,000.00	(14,800,000.00)	0.00	256.85	2,446.58	(2,189.73)	-5.40035%	9.00000%	0.00	256.85	(2,189.73)	N/A	28-May-95
29-May-95	0.00	14,800,000.00	(14,800,000.00)	0.00	256.85	2,446.58	(2,189.73)	-5.40035%	9.00000%	0.00	256.85	(2,189.73)	N/A	29-May-95
30-May-95	0.00	15,500,000.00	(15,500,000.00)	0.00	256.85	2,567.81	(2,310.96)	-5.44194%	9.00000%	0.00	256.85	(2,310.96)	N/A	30-May-95
31-May-95	0.00	13,900,000.00	(13,900,000.00)	0.00	256.85	2,313.84	(2,056.99)	-5.40144%	9.00000%	0.00	256.85	(2,056.99)	N/A	31-May-95
				0.00	7,962.33	61,951.77	(53,989.44)			0.00	7,962.33	(53,989.44)		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
0.00		0.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(19,000,000.00)	MINIMUM OUTSTANDING DURING MONTH		
0.00	12,061,290.32	(12,061,290.32)	MONTH-TO-DATE AVERAGE OUTSTANDING	0.00	
		(53,989.44)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(53,989.44)	
N.A.	-6.0477%	5.2704%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
N.A.		6.0477%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: June 30, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jun-95	0.00	3,700,000.00	(3,700,000.00)	0.00	256.85	609.23	(352.38)	-3.47621%	9.00000%	0.00	256.85	(352.38)	N/A	01-Jun-95
02-Jun-95	0.00	5,300,000.00	(5,300,000.00)	0.00	256.85	871.23	(614.38)	-4.23111%	9.00000%	0.00	256.85	(614.38)	N/A	02-Jun-95
03-Jun-95	0.00	5,300,000.00	(5,300,000.00)	0.00	256.85	871.23	(614.38)	-4.23111%	9.00000%	0.00	256.85	(614.38)	N/A	03-Jun-95
04-Jun-95	0.00	5,300,000.00	(5,300,000.00)	0.00	256.85	871.23	(614.38)	-4.23111%	9.00000%	0.00	256.85	(614.38)	N/A	04-Jun-95
05-Jun-95	0.00	5,000,000.00	(5,000,000.00)	0.00	256.85	820.55	(563.70)	-4.11500%	9.00000%	0.00	256.85	(563.70)	N/A	05-Jun-95
06-Jun-95	0.00	6,200,000.00	(6,200,000.00)	0.00	256.85	1,017.48	(760.63)	-4.47790%	9.00000%	0.00	256.85	(760.63)	N/A	06-Jun-95
07-Jun-95	0.00	7,800,000.00	(7,800,000.00)	0.00	256.85	1,280.05	(1,023.21)	-4.78808%	9.00000%	0.00	256.85	(1,023.21)	N/A	07-Jun-95
08-Jun-95	0.00	9,200,000.00	(9,200,000.00)	0.00	256.85	1,509.81	(1,252.96)	-4.97098%	9.00000%	0.00	256.85	(1,252.96)	N/A	08-Jun-95
09-Jun-95	0.00	9,100,000.00	(9,100,000.00)	0.00	256.85	1,493.40	(1,236.55)	-4.95978%	9.00000%	0.00	256.85	(1,236.55)	N/A	09-Jun-95
10-Jun-95	0.00	9,100,000.00	(9,100,000.00)	0.00	256.85	1,493.40	(1,236.55)	-4.95979%	9.00000%	0.00	256.85	(1,236.55)	N/A	10-Jun-95
11-Jun-95	0.00	9,100,000.00	(9,100,000.00)	0.00	256.85	1,493.40	(1,236.55)	-4.95979%	9.00000%	0.00	256.85	(1,236.55)	N/A	11-Jun-95
12-Jun-95	0.00	10,600,000.00	(10,600,000.00)	0.00	256.85	1,739.56	(1,482.71)	-5.10557%	9.00000%	0.00	256.85	(1,482.71)	N/A	12-Jun-95
13-Jun-95	0.00	11,700,000.00	(11,700,000.00)	0.00	256.85	1,920.08	(1,663.23)	-5.18872%	9.00000%	0.00	256.85	(1,663.23)	N/A	13-Jun-95
14-Jun-95	0.00	15,500,000.00	(15,500,000.00)	0.00	256.85	2,540.82	(2,283.97)	-5.37839%	9.00000%	0.00	256.85	(2,283.97)	N/A	14-Jun-95
15-Jun-95	0.00	16,900,000.00	(16,900,000.00)	0.00	256.85	2,774.05	(2,517.21)	-5.43657%	9.00000%	0.00	256.85	(2,517.21)	N/A	15-Jun-95
16-Jun-95	0.00	14,600,000.00	(14,600,000.00)	0.00	256.85	2,395.29	(2,138.44)	-5.34610%	9.00000%	0.00	256.85	(2,138.44)	N/A	16-Jun-95
17-Jun-95	0.00	14,600,000.00	(14,600,000.00)	0.00	256.85	2,395.29	(2,138.44)	-5.34610%	9.00000%	0.00	256.85	(2,138.44)	N/A	17-Jun-95
18-Jun-95	0.00	14,600,000.00	(14,600,000.00)	0.00	256.85	2,395.29	(2,138.44)	-5.34610%	9.00000%	0.00	256.85	(2,138.44)	N/A	18-Jun-95
19-Jun-95	0.00	14,200,000.00	(14,200,000.00)	0.00	256.85	2,329.15	(2,072.30)	-5.32669%	9.00000%	0.00	256.85	(2,072.30)	N/A	19-Jun-95
20-Jun-95	0.00	13,200,000.00	(13,200,000.00)	0.00	256.85	2,165.59	(1,908.74)	-5.27795%	9.00000%	0.00	256.85	(1,908.74)	N/A	20-Jun-95
21-Jun-95	0.00	13,800,000.00	(13,800,000.00)	0.00	256.85	2,264.88	(2,008.03)	-5.31109%	9.00000%	0.00	256.85	(2,008.03)	N/A	21-Jun-95
22-Jun-95	0.00	10,900,000.00	(10,900,000.00)	0.00	256.85	1,782.82	(1,525.97)	-5.10991%	9.00000%	0.00	256.85	(1,525.97)	N/A	22-Jun-95
23-Jun-95	0.00	10,100,000.00	(10,100,000.00)	0.00	256.85	1,651.97	(1,395.12)	-5.04178%	9.00000%	0.00	256.85	(1,395.12)	N/A	23-Jun-95
24-Jun-95	0.00	10,100,000.00	(10,100,000.00)	0.00	256.85	1,651.97	(1,395.12)	-5.04177%	9.00000%	0.00	256.85	(1,395.12)	N/A	24-Jun-95
25-Jun-95	0.00	10,100,000.00	(10,100,000.00)	0.00	256.85	1,651.97	(1,395.12)	-5.04177%	9.00000%	0.00	256.85	(1,395.12)	N/A	25-Jun-95
26-Jun-95	0.00	8,600,000.00	(8,600,000.00)	0.00	256.85	1,408.99	(1,152.14)	-4.88988%	9.00000%	0.00	256.85	(1,152.14)	N/A	26-Jun-95
27-Jun-95	0.00	7,600,000.00	(7,600,000.00)	0.00	256.85	1,243.07	(986.22)	-4.73645%	9.00000%	0.00	256.85	(986.22)	N/A	27-Jun-95
28-Jun-95	0.00	8,700,000.00	(8,700,000.00)	0.00	256.85	1,422.99	(1,166.14)	-4.89241%	9.00000%	0.00	256.85	(1,166.14)	N/A	28-Jun-95
29-Jun-95	0.00	10,100,000.00	(10,100,000.00)	0.00	256.85	1,651.97	(1,395.12)	-5.04178%	9.00000%	0.00	256.85	(1,395.12)	N/A	29-Jun-95
30-Jun-95	3,500,000.00	2,000,000.00	1,500,000.00	636.81	256.85	327.12	566.54	13.78571%	9.00000%	369.86	256.85	626.71	15.25000%	30-Jun-95
				636.81	7,705.48	48,043.89	(39,701.60)			369.86	7,705.48	(39,641.42)		

3,500,000.00		1,500,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(16,900,000.00)	MINIMUM OUTSTANDING DURING MONTH		
116,666.67	9,766,666.67	(9,650,000.00)	MONTH-TO-DATE AVERAGE OUTSTANDING	50,000.00	
		(39,701.60)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(39,641.42)	
86.9982%	-5.9850%	5.0056%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
6.6410%		5.9771%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: July 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jul-95	3,500,000.00	2,000,000.00	1,500,000.00	636.81	256.85	327.12	566.54	13.78579%	9.00000%	369.86	256.85	626.71	15.25000%	01-Jul-95
02-Jul-95	3,500,000.00	2,000,000.00	1,500,000.00	636.81	256.85	327.12	566.54	13.78579%	9.00000%	369.86	256.85	626.71	15.25000%	02-Jul-95
03-Jul-95	900,000.00	0.00	900,000.00	159.50	256.85	0.00	416.35	16.88528%	9.00000%	221.92	256.85	478.77	19.41667%	03-Jul-95
04-Jul-95	900,000.00	0.00	900,000.00	159.50	256.85	0.00	416.35	16.88528%	9.00000%	221.92	256.85	478.77	19.41667%	04-Jul-95
05-Jul-95	600,000.00	0.00	600,000.00	105.81	256.85	0.00	362.66	22.06178%	9.00000%	147.95	256.85	404.79	24.62501%	05-Jul-95
06-Jul-95	0.00	600,000.00	(600,000.00)	0.00	256.85	97.32	159.53	N.A.	9.00000%	0.00	256.85	159.53	N/A	06-Jul-95
07-Jul-95	0.00	1,100,000.00	(1,100,000.00)	0.00	256.85	183.23	73.62	N.A.	8.75000%	0.00	256.85	73.62	N/A	07-Jul-95
08-Jul-95	0.00	1,100,000.00	(1,100,000.00)	0.00	256.85	183.23	73.62	N.A.	8.75000%	0.00	256.85	73.62	N/A	08-Jul-95
09-Jul-95	0.00	1,100,000.00	(1,100,000.00)	0.00	256.85	183.23	73.62	N.A.	8.75000%	0.00	256.85	73.62	N/A	09-Jul-95
10-Jul-95	0.00	2,100,000.00	(2,100,000.00)	0.00	256.85	337.15	(80.30)	-1.39571%	8.75000%	0.00	256.85	(80.30)	N/A	10-Jul-95
11-Jul-95	0.00	3,700,000.00	(3,700,000.00)	0.00	256.85	596.05	(339.21)	-3.34621%	8.75000%	0.00	256.85	(339.21)	N/A	11-Jul-95
12-Jul-95	0.00	5,700,000.00	(5,700,000.00)	0.00	256.85	914.16	(657.31)	-4.20912%	8.75000%	0.00	256.85	(657.31)	N/A	12-Jul-95
13-Jul-95	0.00	6,900,000.00	(6,900,000.00)	0.00	256.85	1,104.14	(847.29)	-4.48203%	8.75000%	0.00	256.85	(847.29)	N/A	13-Jul-95
14-Jul-95	0.00	5,800,000.00	(5,800,000.00)	0.00	256.85	925.10	(668.25)	-4.20534%	8.75000%	0.00	256.85	(668.25)	N/A	14-Jul-95
15-Jul-95	0.00	5,800,000.00	(5,800,000.00)	0.00	256.85	925.10	(668.25)	-4.20537%	8.75000%	0.00	256.85	(668.25)	N/A	15-Jul-95
16-Jul-95	0.00	5,800,000.00	(5,800,000.00)	0.00	256.85	925.10	(668.25)	-4.20537%	8.75000%	0.00	256.85	(668.25)	N/A	16-Jul-95
17-Jul-95	0.00	6,400,000.00	(6,400,000.00)	0.00	256.85	1,023.84	(766.99)	-4.37422%	8.75000%	0.00	256.85	(766.99)	N/A	17-Jul-95
18-Jul-95	0.00	5,900,000.00	(5,900,000.00)	0.00	256.85	941.64	(684.79)	-4.23644%	8.75000%	0.00	256.85	(684.79)	N/A	18-Jul-95
19-Jul-95	0.00	6,500,000.00	(6,500,000.00)	0.00	256.85	1,042.33	(785.48)	-4.41077%	8.75000%	0.00	256.85	(785.48)	N/A	19-Jul-95
20-Jul-95	0.00	6,600,000.00	(6,600,000.00)	0.00	256.85	1,058.79	(801.95)	-4.43500%	8.75000%	0.00	256.85	(801.95)	N/A	20-Jul-95
21-Jul-95	0.00	5,400,000.00	(5,400,000.00)	0.00	256.85	868.82	(611.97)	-4.13648%	8.75000%	0.00	256.85	(611.97)	N/A	21-Jul-95
22-Jul-95	0.00	5,400,000.00	(5,400,000.00)	0.00	256.85	868.82	(611.97)	-4.13647%	8.75000%	0.00	256.85	(611.97)	N/A	22-Jul-95
23-Jul-95	0.00	5,400,000.00	(5,400,000.00)	0.00	256.85	868.82	(611.97)	-4.13647%	8.75000%	0.00	256.85	(611.97)	N/A	23-Jul-95
24-Jul-95	0.00	2,400,000.00	(2,400,000.00)	0.00	256.85	385.97	(129.12)	-1.96375%	8.75000%	0.00	256.85	(129.12)	N/A	24-Jul-95
25-Jul-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	8.75000%	0.00	256.85	256.85	N/A	25-Jul-95
26-Jul-95	0.00	300,000.00	(300,000.00)	0.00	256.85	48.00	208.85	N.A.	8.75000%	0.00	256.85	208.85	N/A	26-Jul-95
27-Jul-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	8.75000%	0.00	256.85	256.85	N/A	27-Jul-95
28-Jul-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	8.75000%	0.00	256.85	256.85	N/A	28-Jul-95
29-Jul-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	8.75000%	0.00	256.85	256.85	N/A	29-Jul-95
30-Jul-95	0.00	0.00	0.00	0.00	256.85	0.00	256.85	N.A.	8.75000%	0.00	256.85	256.85	N/A	30-Jul-95
31-Jul-95	7,000,000.00	0.00	7,000,000.00	1,185.88	256.85	0.00	1,442.73	7.52280%	8.75000%	1,678.08	256.85	1,934.93	10.08929%	31-Jul-95
				2,884.31	7,962.33	14,135.09	(3,288.44)			3,009.59	7,962.33	(2,508.93)		

7,000,000.00		7,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(6,900,000.00)	MINIMUM OUTSTANDING DURING MONTH		
529,032.26	2,838,709.68	(2,309,677.42)	MONTH-TO-DATE AVERAGE OUTSTANDING	400,000.00	
		(3,288.44)	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	(2,508.93)	
24.1404%	-5.8628%	1.6764%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	N/A	(5)
6.4193%		5.7354%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: August 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Aug-95	8,600,000.00	0.00	8,600,000.00	1,434.53	256.85	0.00	1,691.38	7.17853%	8.75000%	2,061.64	256.85	2,318.49	9.84012%	01-Aug-95
02-Aug-95	8,000,000.00	0.00	8,000,000.00	1,333.33	256.85	0.00	1,590.18	7.25519%	8.75000%	1,917.81	256.85	2,174.66	9.92188%	02-Aug-95
03-Aug-95	7,600,000.00	0.00	7,600,000.00	1,267.72	256.85	0.00	1,524.57	7.32195%	8.75000%	1,821.92	256.85	2,078.77	9.98355%	03-Aug-95
04-Aug-95	6,600,000.00	0.00	6,600,000.00	1,094.27	256.85	0.00	1,351.12	7.47210%	8.75000%	1,582.19	256.85	1,839.04	10.17046%	04-Aug-95
05-Aug-95	6,600,000.00	0.00	6,600,000.00	1,094.27	256.85	0.00	1,351.12	7.47210%	8.75000%	1,582.19	256.85	1,839.04	10.17046%	05-Aug-95
06-Aug-95	6,600,000.00	0.00	6,600,000.00	1,094.27	256.85	0.00	1,351.12	7.47210%	8.75000%	1,582.19	256.85	1,839.04	10.17046%	06-Aug-95
07-Aug-95	5,500,000.00	0.00	5,500,000.00	912.66	256.85	0.00	1,169.51	7.76129%	8.75000%	1,318.49	256.85	1,575.34	10.45455%	07-Aug-95
08-Aug-95	4,900,000.00	0.00	4,900,000.00	808.84	256.85	0.00	1,065.69	7.93830%	8.75000%	1,174.66	256.85	1,431.51	10.66327%	08-Aug-95
09-Aug-95	2,700,000.00	0.00	2,700,000.00	441.00	256.85	0.00	697.85	9.43389%	8.75000%	647.26	256.85	904.11	12.22222%	09-Aug-95
10-Aug-95	1,000,000.00	0.00	1,000,000.00	163.33	256.85	0.00	420.18	15.33655%	8.75000%	239.73	256.85	496.58	18.12501%	10-Aug-95
11-Aug-95	0.00	200,000.00	(200,000.00)	0.00	256.85	31.78	225.07	N.A.	8.75000%	0.00	256.85	225.07	N/A	11-Aug-95
12-Aug-95	0.00	200,000.00	(200,000.00)	0.00	256.85	31.78	225.07	N.A.	8.75000%	0.00	256.85	225.07	N/A	12-Aug-95
13-Aug-95	0.00	200,000.00	(200,000.00)	0.00	256.85	31.78	225.07	N.A.	8.75000%	0.00	256.85	225.07	N/A	13-Aug-95
14-Aug-95	0.00	1,500,000.00	(1,500,000.00)	0.00	271.15	238.77	32.38	N.A.	8.75000%	0.00	271.15	32.38	N/A	14-Aug-95
15-Aug-95	0.00	2,000,000.00	(2,000,000.00)	0.00	271.15	318.90	(47.75)	-0.87151%	8.75000%	0.00	271.15	(47.75)	N/A	15-Aug-95
16-Aug-95	0.00	1,300,000.00	(1,300,000.00)	0.00	271.15	207.29	63.86	N.A.	8.75000%	0.00	271.15	63.86	N/A	16-Aug-95
17-Aug-95	0.00	1,300,000.00	(1,300,000.00)	0.00	271.15	206.93	64.22	N.A.	8.75000%	0.00	271.15	64.22	N/A	17-Aug-95
18-Aug-95	300,000.00	0.00	300,000.00	49.00	271.15	0.00	320.15	38.95161%	8.75000%	71.92	271.15	343.07	41.73994%	18-Aug-95
19-Aug-95	300,000.00	0.00	300,000.00	49.00	271.15	0.00	320.15	38.95161%	8.75000%	71.92	271.15	343.07	41.73994%	19-Aug-95
20-Aug-95	300,000.00	0.00	300,000.00	49.00	271.15	0.00	320.15	38.95161%	8.75000%	71.92	271.15	343.07	41.73994%	20-Aug-95
21-Aug-95	1,400,000.00	0.00	1,400,000.00	228.67	271.15	0.00	499.82	13.03103%	8.75000%	335.62	271.15	606.77	15.81927%	21-Aug-95
22-Aug-95	2,800,000.00	0.00	2,800,000.00	457.33	271.15	0.00	728.48	9.49626%	8.75000%	671.23	271.15	942.38	12.28464%	22-Aug-95
23-Aug-95	2,600,000.00	0.00	2,600,000.00	422.41	271.15	0.00	693.56	9.73652%	8.75000%	623.29	271.15	894.44	12.55653%	23-Aug-95
24-Aug-95	2,200,000.00	0.00	2,200,000.00	357.43	271.15	0.00	628.58	10.42872%	8.75000%	527.40	271.15	798.55	13.24863%	24-Aug-95
25-Aug-95	4,700,000.00	0.00	4,700,000.00	767.67	271.15	0.00	1,038.82	8.06743%	8.75000%	1,126.71	271.15	1,397.86	10.85574%	25-Aug-95
26-Aug-95	4,700,000.00	0.00	4,700,000.00	767.67	271.15	0.00	1,038.82	8.06743%	8.75000%	1,126.71	271.15	1,397.86	10.85574%	26-Aug-95
27-Aug-95	4,700,000.00	0.00	4,700,000.00	767.67	271.15	0.00	1,038.82	8.06743%	8.75000%	1,126.71	271.15	1,397.86	10.85574%	27-Aug-95
28-Aug-95	5,200,000.00	0.00	5,200,000.00	858.36	271.15	0.00	1,129.51	7.92829%	8.75000%	1,246.58	271.15	1,517.73	10.65327%	28-Aug-95
29-Aug-95	4,700,000.00	0.00	4,700,000.00	762.44	271.15	0.00	1,033.59	8.02682%	8.75000%	1,126.71	271.15	1,397.86	10.85574%	29-Aug-95
30-Aug-95	4,200,000.00	0.00	4,200,000.00	688.33	271.15	0.00	959.48	8.33834%	8.75000%	1,006.85	271.15	1,278.00	11.10642%	30-Aug-95
31-Aug-95	14,200,000.00	0.00	14,200,000.00	2,370.39	271.15	0.00	2,641.54	6.78987%	8.75000%	3,404.11	271.15	3,675.26	9.44697%	31-Aug-95
				18,239.59	8,219.75	1,067.23	25,392.11			26,465.75	8,219.75	33,618.27		

14,200,000.00		14,200,000.00	MAXIMUM OUTSTANDING DURING MONTH	
0.00		(2,000,000.00)	MINIMUM OUTSTANDING DURING MONTH	
3,561,290.32	216,129.03	3,345,161.29	MONTH-TO-DATE AVERAGE OUTSTANDING	3,561,290.32
		25,392.11	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	33,618.27
8.7479%	-5.8140%	8.9374%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	11.1147% (5)
6.0303%		6.0443%	ABOVE RATES NET OF COMMITMENT FEES	

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
OM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: September 30, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Sep-95	15,400,000.00	0.00	15,400,000.00	2,518.82	270.55	0.00	2,789.37	6.61116%	8.75000%	3,691.78	270.55	3,962.33	9.39123%	01-Sep-95
02-Sep-95	15,400,000.00	0.00	15,400,000.00	2,518.82	270.55	0.00	2,789.37	6.61116%	8.75000%	3,691.78	270.55	3,962.33	9.39123%	02-Sep-95
03-Sep-95	15,400,000.00	0.00	15,400,000.00	2,518.82	270.55	0.00	2,789.37	6.61116%	8.75000%	3,691.78	270.55	3,962.33	9.39123%	03-Sep-95
04-Sep-95	15,400,000.00	0.00	15,400,000.00	2,518.82	270.55	0.00	2,789.37	6.61116%	8.75000%	3,691.78	270.55	3,962.33	9.39123%	04-Sep-95
05-Sep-95	15,800,000.00	0.00	15,800,000.00	2,604.44	270.55	0.00	2,874.99	6.64159%	8.75000%	3,787.67	270.55	4,058.22	9.37500%	05-Sep-95
06-Sep-95	16,600,000.00	0.00	16,600,000.00	2,744.33	270.55	0.00	3,014.88	6.62910%	8.75000%	3,979.45	270.55	4,250.00	9.34488%	06-Sep-95
07-Sep-95	14,400,000.00	0.00	14,400,000.00	2,371.09	270.55	0.00	2,641.64	6.69582%	8.75000%	3,452.05	270.55	3,722.60	9.43576%	07-Sep-95
08-Sep-95	17,000,000.00	0.00	17,000,000.00	2,782.93	270.55	0.00	3,053.48	6.55600%	8.75000%	4,075.34	270.55	4,345.89	9.33088%	08-Sep-95
09-Sep-95	17,000,000.00	0.00	17,000,000.00	2,782.93	270.55	0.00	3,053.48	6.55600%	8.75000%	4,075.34	270.55	4,345.89	9.33088%	09-Sep-95
10-Sep-95	17,000,000.00	0.00	17,000,000.00	2,782.93	270.55	0.00	3,053.48	6.55600%	8.75000%	4,075.34	270.55	4,345.89	9.33088%	10-Sep-95
11-Sep-95	13,400,000.00	0.00	13,400,000.00	2,200.32	270.55	0.00	2,470.87	6.73035%	8.75000%	3,212.33	270.55	3,482.88	9.48694%	11-Sep-95
12-Sep-95	10,600,000.00	0.00	10,600,000.00	1,727.17	270.55	0.00	1,997.72	6.87893%	8.75000%	2,541.10	270.55	2,811.64	9.68160%	12-Sep-95
13-Sep-95	8,200,000.00	0.00	8,200,000.00	1,360.70	270.55	0.00	1,631.25	7.26104%	8.75000%	1,965.75	270.55	2,236.30	9.95427%	13-Sep-95
14-Sep-95	7,500,000.00	0.00	7,500,000.00	1,235.68	270.55	0.00	1,506.23	7.33031%	8.75000%	1,797.95	270.55	2,068.49	10.06667%	14-Sep-95
15-Sep-95	8,600,000.00	0.00	8,600,000.00	1,435.92	270.55	0.00	1,706.47	7.24257%	8.75000%	2,061.64	270.55	2,332.19	9.89826%	15-Sep-95
16-Sep-95	8,600,000.00	0.00	8,600,000.00	1,435.92	270.55	0.00	1,706.47	7.24257%	8.75000%	2,061.64	270.55	2,332.19	9.89826%	16-Sep-95
17-Sep-95	8,600,000.00	0.00	8,600,000.00	1,435.92	270.55	0.00	1,706.47	7.24257%	8.75000%	2,061.64	270.55	2,332.19	9.89826%	17-Sep-95
18-Sep-95	11,500,000.00	0.00	11,500,000.00	1,898.30	270.55	0.00	2,168.85	6.88374%	8.75000%	2,756.85	270.55	3,027.40	9.60870%	18-Sep-95
19-Sep-95	12,200,000.00	0.00	12,200,000.00	2,009.33	270.55	0.00	2,279.88	6.82095%	8.75000%	2,924.66	270.55	3,195.21	9.55943%	19-Sep-95
20-Sep-95	11,500,000.00	0.00	11,500,000.00	1,893.78	270.55	0.00	2,164.33	6.86939%	8.75000%	2,756.85	270.55	3,027.40	9.60870%	20-Sep-95
21-Sep-95	12,200,000.00	0.00	12,200,000.00	2,003.27	270.55	0.00	2,273.82	6.80282%	8.75000%	2,924.66	270.55	3,195.21	9.55943%	21-Sep-95
22-Sep-95	14,200,000.00	0.00	14,200,000.00	2,321.88	270.55	0.00	2,592.43	6.66364%	8.75000%	3,404.11	270.55	3,674.66	9.44542%	22-Sep-95
23-Sep-95	14,200,000.00	0.00	14,200,000.00	2,321.88	270.55	0.00	2,592.43	6.66364%	8.75000%	3,404.11	270.55	3,674.66	9.44542%	23-Sep-95
24-Sep-95	14,200,000.00	0.00	14,200,000.00	2,321.88	270.55	0.00	2,592.43	6.66364%	8.75000%	3,404.11	270.55	3,674.66	9.44542%	24-Sep-95
25-Sep-95	5,700,000.00	0.00	5,700,000.00	935.96	270.55	0.00	1,206.51	7.72589%	8.75000%	1,366.44	270.55	1,636.99	10.48246%	25-Sep-95
26-Sep-95	5,900,000.00	0.00	5,900,000.00	960.28	270.55	0.00	1,230.83	7.61444%	8.75000%	1,414.38	270.55	1,684.93	10.42373%	26-Sep-95
27-Sep-95	6,400,000.00	0.00	6,400,000.00	1,062.70	270.55	0.00	1,333.25	7.60368%	8.75000%	1,534.25	270.55	1,804.79	10.29297%	27-Sep-95
28-Sep-95	5,600,000.00	0.00	5,600,000.00	940.54	270.55	0.00	1,211.09	7.89370%	8.75000%	1,342.47	270.55	1,613.01	10.51339%	28-Sep-95
29-Sep-95	23,500,000.00	3,000,000.00	20,500,000.00	4,508.34	270.55	475.89	4,303.00	7.66143%	8.75000%	4,914.38	270.55	5,184.93	9.23171%	29-Sep-95
30-Sep-95	23,500,000.00	3,000,000.00	20,500,000.00	4,508.34	270.55	475.89	4,303.00	7.66144%	8.75000%	4,914.38	270.55	5,184.93	9.23171%	30-Sep-95
				64,662.04	8,116.44	951.78	71,826.70			90,976.03	8,116.44	99,092.47		

23,500,000.00		20,500,000.00	MAXIMUM OUTSTANDING DURING MONTH		
5,600,000.00		5,600,000.00	MINIMUM OUTSTANDING DURING MONTH		
12,435,483.87	193,548.39	12,241,935.48	MONTH-TO-DATE AVERAGE OUTSTANDING	12,241,935.48	
		71,826.70	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	99,092.47	
6.8908%	-5.7900%	6.9082%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	9.5306%	(5)
6.1223%		6.1276%	ABOVE RATES NET OF COMMITMENT FEES		

) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: October 31, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Oct-95	23,500,000.00	3,000,000.00	20,500,000.00	4,508.34	270.55	475.89	4,303.00	7.66144%	8.75000%	4,914.38	270.55	5,184.93	9.23171%	01-Oct-95
02-Oct-95	20,000,000.00	0.00	20,000,000.00	3,401.39	270.55	0.00	3,671.94	6.70129%	8.75000%	4,794.52	270.55	5,065.07	9.24375%	02-Oct-95
03-Oct-95	20,900,000.00	0.00	20,900,000.00	3,456.91	270.55	0.00	3,727.46	6.50968%	8.75000%	5,010.27	270.55	5,280.82	9.22249%	03-Oct-95
04-Oct-95	20,200,000.00	0.00	20,200,000.00	3,305.28	270.55	0.00	3,575.83	6.46127%	8.75000%	4,842.47	270.55	5,113.01	9.23886%	04-Oct-95
05-Oct-95	19,500,000.00	0.00	19,500,000.00	3,190.00	270.55	0.00	3,460.55	6.47744%	8.75000%	4,674.66	270.55	4,945.21	9.25641%	05-Oct-95
06-Oct-95	18,300,000.00	0.00	18,300,000.00	2,974.17	270.55	0.00	3,244.72	6.47171%	8.75000%	4,386.99	270.55	4,657.53	9.28962%	06-Oct-95
07-Oct-95	18,300,000.00	0.00	18,300,000.00	2,974.17	270.55	0.00	3,244.72	6.47171%	8.75000%	4,386.99	270.55	4,657.53	9.28962%	07-Oct-95
08-Oct-95	18,300,000.00	0.00	18,300,000.00	2,974.17	270.55	0.00	3,244.72	6.47171%	8.75000%	4,386.99	270.55	4,657.53	9.28962%	08-Oct-95
09-Oct-95	18,300,000.00	0.00	18,300,000.00	2,974.17	270.55	0.00	3,244.72	6.47171%	8.75000%	4,386.99	270.55	4,657.53	9.28962%	09-Oct-95
10-Oct-95	15,200,000.00	0.00	15,200,000.00	2,510.10	270.55	0.00	2,780.65	6.67721%	8.75000%	3,643.84	270.55	3,914.38	9.39967%	10-Oct-95
11-Oct-95	12,100,000.00	0.00	12,100,000.00	2,014.88	270.55	0.00	2,285.43	6.89406%	8.75000%	2,900.68	270.55	3,171.23	9.56612%	11-Oct-95
12-Oct-95	9,800,000.00	0.00	9,800,000.00	1,615.89	270.55	0.00	1,886.44	7.02602%	8.75000%	2,349.32	270.55	2,619.86	9.75765%	12-Oct-95
13-Oct-95	8,500,000.00	0.00	8,500,000.00	1,397.90	270.55	0.00	1,668.45	7.16451%	8.75000%	2,037.67	270.55	2,308.22	9.91177%	13-Oct-95
14-Oct-95	8,500,000.00	0.00	8,500,000.00	1,397.90	270.55	0.00	1,668.45	7.16451%	8.75000%	2,037.67	270.55	2,308.22	9.91177%	14-Oct-95
15-Oct-95	8,500,000.00	0.00	8,500,000.00	1,397.90	270.55	0.00	1,668.45	7.16451%	8.75000%	2,037.67	270.55	2,308.22	9.91177%	15-Oct-95
16-Oct-95	8,900,000.00	0.00	8,900,000.00	1,467.07	270.55	0.00	1,737.62	7.12619%	8.75000%	2,133.56	270.55	2,404.11	9.85955%	16-Oct-95
17-Oct-95	8,700,000.00	0.00	8,700,000.00	1,419.25	270.55	0.00	1,689.80	7.08938%	8.75000%	2,085.62	270.55	2,356.16	9.88506%	17-Oct-95
18-Oct-95	8,500,000.00	0.00	8,500,000.00	1,383.33	270.55	0.00	1,653.88	7.10195%	8.75000%	2,037.67	270.55	2,308.22	9.91177%	18-Oct-95
19-Oct-95	7,800,000.00	0.00	7,800,000.00	1,262.63	270.55	0.00	1,533.18	7.17449%	8.75000%	1,869.86	270.55	2,140.41	10.01603%	19-Oct-95
20-Oct-95	9,700,000.00	0.00	9,700,000.00	1,578.62	270.55	0.00	1,849.17	6.95821%	8.75000%	2,325.34	270.55	2,595.89	9.76804%	20-Oct-95
21-Oct-95	9,700,000.00	0.00	9,700,000.00	1,578.62	270.55	0.00	1,849.17	6.95821%	8.75000%	2,325.34	270.55	2,595.89	9.76804%	21-Oct-95
22-Oct-95	9,700,000.00	0.00	9,700,000.00	1,578.62	270.55	0.00	1,849.17	6.95821%	8.75000%	2,325.34	270.55	2,595.89	9.76804%	22-Oct-95
23-Oct-95	9,300,000.00	0.00	9,300,000.00	1,529.67	270.55	0.00	1,800.22	7.06537%	8.75000%	2,229.45	270.55	2,500.00	9.81183%	23-Oct-95
24-Oct-95	10,500,000.00	0.00	10,500,000.00	1,717.92	270.55	0.00	1,988.47	6.91229%	8.75000%	2,517.12	270.55	2,787.67	9.69048%	24-Oct-95
25-Oct-95	12,200,000.00	0.00	12,200,000.00	2,039.82	270.55	0.00	2,310.37	6.91217%	8.75000%	2,924.66	270.55	3,195.21	9.55943%	25-Oct-95
26-Oct-95	12,000,000.00	0.00	12,000,000.00	1,973.77	270.55	0.00	2,244.32	6.82647%	8.75000%	2,876.71	270.55	3,147.26	9.57292%	26-Oct-95
27-Oct-95	11,600,000.00	0.00	11,600,000.00	1,887.84	270.55	0.00	2,158.39	6.79148%	8.75000%	2,780.82	270.55	3,051.37	9.60129%	27-Oct-95
28-Oct-95	11,600,000.00	0.00	11,600,000.00	1,887.84	270.55	0.00	2,158.39	6.79148%	8.75000%	2,780.82	270.55	3,051.37	9.60129%	28-Oct-95
29-Oct-95	11,600,000.00	0.00	11,600,000.00	1,887.84	270.55	0.00	2,158.39	6.79148%	8.75000%	2,780.82	270.55	3,051.37	9.60129%	29-Oct-95
30-Oct-95	11,200,000.00	0.00	11,200,000.00	1,847.37	270.55	0.00	2,117.92	6.90214%	8.75000%	2,684.93	270.55	2,955.48	9.63170%	30-Oct-95
31-Oct-95	18,100,000.00	0.00	18,100,000.00	3,051.81	270.55	0.00	3,322.36	6.69978%	8.75000%	4,339.04	270.55	4,609.59	9.29558%	31-Oct-95
				68,185.19	8,386.99	475.89	76,096.29			97,808.22	8,386.99	106,195.21		

		20,900,000.00	MAXIMUM OUTSTANDING DURING MONTH		
23,500,000.00		7,800,000.00	MINIMUM OUTSTANDING DURING MONTH	13,161,290.32	
7,800,000.00		13,161,290.32	MONTH-TO-DATE AVERAGE OUTSTANDING	106,195.21	
13,258,064.52	96,774.19	76,096.29	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	9.5003%	(5)
6.8002%	-5.7900%	6.8076%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)		
6.0554%		6.0573%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: November 30, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Nov-95	19,400,000.00	0.00	19,400,000.00	3,224.08	270.55	0.00	3,494.63	6.57494%	8.75000%	4,650.68	270.55	4,921.23	9.25902%	01-Nov-95
02-Nov-95	18,700,000.00	0.00	18,700,000.00	3,086.53	270.55	0.00	3,357.08	6.55259%	8.75000%	4,482.88	270.55	4,753.42	9.27808%	02-Nov-95
03-Nov-95	18,100,000.00	0.00	18,100,000.00	2,945.78	270.55	0.00	3,216.33	6.48597%	8.75000%	4,339.04	270.55	4,609.59	9.29558%	03-Nov-95
04-Nov-95	18,100,000.00	0.00	18,100,000.00	2,945.78	270.55	0.00	3,216.33	6.48597%	8.75000%	4,339.04	270.55	4,609.59	9.29558%	04-Nov-95
05-Nov-95	18,100,000.00	0.00	18,100,000.00	2,945.78	270.55	0.00	3,216.33	6.48597%	8.75000%	4,339.04	270.55	4,609.59	9.29558%	05-Nov-95
06-Nov-95	17,000,000.00	0.00	17,000,000.00	2,795.99	270.55	0.00	3,066.54	6.58404%	8.75000%	4,075.34	270.55	4,345.89	9.33088%	06-Nov-95
07-Nov-95	16,300,000.00	0.00	16,300,000.00	2,667.95	270.55	0.00	2,938.50	6.58007%	8.75000%	3,907.53	270.55	4,178.08	9.35583%	07-Nov-95
08-Nov-95	15,600,000.00	0.00	15,600,000.00	2,620.44	270.55	0.00	2,890.99	6.76417%	8.75000%	3,739.73	270.55	4,010.27	9.38301%	08-Nov-95
09-Nov-95	14,700,000.00	0.00	14,700,000.00	2,417.86	270.55	0.00	2,688.41	6.67530%	8.75000%	3,523.97	270.55	3,794.52	9.42177%	09-Nov-95
10-Nov-95	14,100,000.00	0.00	14,100,000.00	2,304.14	270.55	0.00	2,574.69	6.66497%	8.75000%	3,380.14	270.55	3,650.69	9.45035%	10-Nov-95
11-Nov-95	14,100,000.00	0.00	14,100,000.00	2,304.14	270.55	0.00	2,574.69	6.66497%	8.75000%	3,380.14	270.55	3,650.69	9.45035%	11-Nov-95
12-Nov-95	14,100,000.00	0.00	14,100,000.00	2,304.14	270.55	0.00	2,574.69	6.66497%	8.75000%	3,380.14	270.55	3,650.69	9.45035%	12-Nov-95
13-Nov-95	13,300,000.00	0.00	13,300,000.00	2,187.59	270.55	0.00	2,458.14	6.74602%	8.75000%	3,188.36	270.55	3,458.90	9.49248%	13-Nov-95
14-Nov-95	12,600,000.00	0.00	12,600,000.00	2,072.46	270.55	0.00	2,343.01	6.78729%	8.75000%	3,020.55	270.55	3,291.10	9.53373%	14-Nov-95
15-Nov-95	12,400,000.00	0.00	12,400,000.00	2,104.14	270.55	0.00	2,374.69	6.99001%	8.75000%	2,972.60	270.55	3,243.15	9.54637%	15-Nov-95
16-Nov-95	13,700,000.00	0.00	13,700,000.00	2,277.17	270.55	0.00	2,547.72	6.78772%	8.75000%	3,284.25	270.55	3,554.79	9.47080%	16-Nov-95
17-Nov-95	13,500,000.00	0.00	13,500,000.00	2,220.49	270.55	0.00	2,491.04	6.73503%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	17-Nov-95
18-Nov-95	13,500,000.00	0.00	13,500,000.00	2,220.49	270.55	0.00	2,491.04	6.73503%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	18-Nov-95
19-Nov-95	13,500,000.00	0.00	13,500,000.00	2,220.49	270.55	0.00	2,491.04	6.73503%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	19-Nov-95
20-Nov-95	15,000,000.00	0.00	15,000,000.00	2,485.78	270.55	0.00	2,756.33	6.70707%	8.75000%	3,595.89	270.55	3,866.44	9.40833%	20-Nov-95
21-Nov-95	15,100,000.00	0.00	15,100,000.00	2,493.62	270.55	0.00	2,764.17	6.68160%	8.75000%	3,619.86	270.55	3,890.41	9.40397%	21-Nov-95
22-Nov-95	16,700,000.00	0.00	16,700,000.00	2,836.36	270.55	0.00	3,106.91	6.79055%	8.75000%	4,003.42	270.55	4,273.97	9.34132%	22-Nov-95
23-Nov-95	16,700,000.00	0.00	16,700,000.00	2,836.36	270.55	0.00	3,106.91	6.79055%	8.75000%	4,003.42	270.55	4,273.97	9.34132%	23-Nov-95
24-Nov-95	17,200,000.00	0.00	17,200,000.00	2,980.08	270.55	0.00	3,250.63	6.89814%	8.75000%	4,123.29	270.55	4,393.84	9.32413%	24-Nov-95
25-Nov-95	17,200,000.00	0.00	17,200,000.00	2,980.08	270.55	0.00	3,250.63	6.89814%	8.75000%	4,123.29	270.55	4,393.84	9.32413%	25-Nov-95
26-Nov-95	17,200,000.00	0.00	17,200,000.00	2,980.08	270.55	0.00	3,250.63	6.89814%	8.75000%	4,123.29	270.55	4,393.84	9.32413%	26-Nov-95
27-Nov-95	18,400,000.00	0.00	18,400,000.00	3,091.62	270.55	0.00	3,362.17	6.66952%	8.75000%	4,410.96	270.55	4,681.51	9.28669%	27-Nov-95
28-Nov-95	17,800,000.00	0.00	17,800,000.00	2,928.43	270.55	0.00	3,198.98	6.55970%	8.75000%	4,267.12	270.55	4,537.67	9.30478%	28-Nov-95
29-Nov-95	16,100,000.00	0.00	16,100,000.00	2,633.53	270.55	0.00	2,904.08	6.58378%	8.75000%	3,859.59	270.55	4,130.14	9.36335%	29-Nov-95
30-Nov-95	18,700,000.00	0.00	18,700,000.00	3,186.61	270.55	0.00	3,457.16	6.74793%	8.75000%	4,482.88	270.55	4,753.42	9.27808%	30-Nov-95
				79,297.99	8,116.44	0.00	87,414.43			114,325.34	8,116.44	122,441.78		

19,400,000.00		19,400,000.00	MAXIMUM OUTSTANDING DURING MONTH		
12,400,000.00		12,400,000.00	MINIMUM OUTSTANDING DURING MONTH		
15,896,666.67	0.00	15,896,666.67	MONTH-TO-DATE AVERAGE OUTSTANDING	15,896,666.67	
		87,414.43	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	122,441.78	
6.6903%	N.A.	6.6903%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	9.3712%	(5)
6.0691%		6.0691%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: DECEMBER 29, 1995

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Dec-95	21,100,000.00	0.00	21,100,000.00	3,520.94	270.55	0.00	3,791.49	6.55874%	8.75000%	5,058.22	270.55	5,328.77	9.21801%	01-Dec-95
02-Dec-95	21,100,000.00	0.00	21,100,000.00	3,520.94	270.55	0.00	3,791.49	6.55874%	8.75000%	5,058.22	270.55	5,328.77	9.21801%	02-Dec-95
03-Dec-95	21,100,000.00	0.00	21,100,000.00	3,520.94	270.55	0.00	3,791.49	6.55874%	8.75000%	5,058.22	270.55	5,328.77	9.21801%	03-Dec-95
04-Dec-95	19,700,000.00	0.00	19,700,000.00	3,241.40	270.55	0.00	3,511.95	6.50691%	8.75000%	4,722.60	270.55	4,993.15	9.25127%	04-Dec-95
05-Dec-95	19,900,000.00	0.00	19,900,000.00	3,261.31	270.55	0.00	3,531.86	6.47803%	8.75000%	4,770.55	270.55	5,041.10	9.24623%	05-Dec-95
06-Dec-95	17,900,000.00	0.00	17,900,000.00	3,038.33	270.55	0.00	3,308.88	6.74715%	8.75000%	4,291.10	270.55	4,561.64	9.30168%	06-Dec-95
07-Dec-95	17,000,000.00	0.00	17,000,000.00	2,826.03	270.55	0.00	3,096.58	6.64854%	8.75000%	4,075.34	270.55	4,345.89	9.33088%	07-Dec-95
08-Dec-95	19,500,000.00	0.00	19,500,000.00	3,195.42	270.55	0.00	3,465.97	6.48758%	8.75000%	4,674.66	270.55	4,945.21	9.25641%	08-Dec-95
09-Dec-95	19,500,000.00	0.00	19,500,000.00	3,195.42	270.55	0.00	3,465.97	6.48758%	8.75000%	4,674.66	270.55	4,945.21	9.25641%	09-Dec-95
10-Dec-95	19,500,000.00	0.00	19,500,000.00	3,195.42	270.55	0.00	3,465.97	6.48758%	8.75000%	4,674.66	270.55	4,945.21	9.25641%	10-Dec-95
11-Dec-95	17,700,000.00	0.00	17,700,000.00	2,911.96	270.55	0.00	3,182.51	6.56280%	8.75000%	4,243.15	270.55	4,513.70	9.30791%	11-Dec-95
12-Dec-95	16,200,000.00	0.00	16,200,000.00	2,647.72	270.55	0.00	2,918.27	6.57511%	8.75000%	3,883.56	270.55	4,154.11	9.35957%	12-Dec-95
13-Dec-95	14,100,000.00	0.00	14,100,000.00	2,304.14	270.55	0.00	2,574.69	6.66497%	8.75000%	3,380.14	270.55	3,650.69	9.45035%	13-Dec-95
14-Dec-95	12,100,000.00	0.00	12,100,000.00	1,969.21	270.55	0.00	2,239.76	6.75630%	8.75000%	2,900.68	270.55	3,171.23	9.56612%	14-Dec-95
15-Dec-95	13,500,000.00	0.00	13,500,000.00	2,275.25	270.55	0.00	2,545.80	6.88308%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	15-Dec-95
16-Dec-95	13,500,000.00	0.00	13,500,000.00	2,275.25	270.55	0.00	2,545.80	6.88308%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	16-Dec-95
17-Dec-95	13,500,000.00	0.00	13,500,000.00	2,275.25	270.55	0.00	2,545.80	6.88308%	8.75000%	3,236.30	270.55	3,506.85	9.48148%	17-Dec-95
18-Dec-95	12,000,000.00	0.00	12,000,000.00	1,963.33	270.55	0.00	2,233.88	6.79471%	8.75000%	2,876.71	270.55	3,147.26	9.57292%	18-Dec-95
19-Dec-95	12,100,000.00	0.00	12,100,000.00	1,967.42	270.55	0.00	2,237.97	6.75090%	8.75000%	2,900.68	270.55	3,171.23	9.56612%	19-Dec-95
20-Dec-95	11,400,000.00	0.00	11,400,000.00	1,853.28	270.55	0.00	2,123.83	6.79998%	8.50000%	2,654.79	270.55	2,925.34	9.36623%	20-Dec-95
21-Dec-95	11,800,000.00	0.00	11,800,000.00	1,910.13	270.55	0.00	2,180.68	6.74532%	8.50000%	2,747.95	270.55	3,018.49	9.33686%	21-Dec-95
22-Dec-95	13,200,000.00	0.00	13,200,000.00	2,132.77	270.55	0.00	2,403.32	6.64554%	8.50000%	3,073.97	270.55	3,344.52	9.24811%	22-Dec-95
23-Dec-95	13,200,000.00	0.00	13,200,000.00	2,132.77	270.55	0.00	2,403.32	6.64554%	8.50000%	3,073.97	270.55	3,344.52	9.24811%	23-Dec-95
24-Dec-95	13,200,000.00	0.00	13,200,000.00	2,132.77	270.55	0.00	2,403.32	6.64554%	8.50000%	3,073.97	270.55	3,344.52	9.24811%	24-Dec-95
25-Dec-95	13,200,000.00	0.00	13,200,000.00	2,132.77	270.55	0.00	2,403.32	6.64554%	8.50000%	3,073.97	270.55	3,344.52	9.24811%	25-Dec-95
26-Dec-95	16,200,000.00	0.00	16,200,000.00	2,613.67	270.55	0.00	2,884.22	6.49839%	8.50000%	3,772.60	270.55	4,043.15	9.10957%	26-Dec-95
27-Dec-95	17,300,000.00	0.00	17,300,000.00	2,732.75	270.55	0.00	3,003.30	6.33644%	8.50000%	4,028.77	270.55	4,299.32	9.07081%	27-Dec-95
28-Dec-95	16,700,000.00	0.00	16,700,000.00	2,591.11	270.55	0.00	2,861.66	6.25452%	8.50000%	3,889.04	270.55	4,159.59	9.09132%	28-Dec-95
29-Dec-95	30,700,000.00	2,000,000.00	28,700,000.00	5,204.95	270.55	312.88	5,162.62	6.56570%	8.50000%	6,683.56	270.55	6,954.11	8.84408%	29-Dec-95
30-Dec-95	30,700,000.00	2,000,000.00	28,700,000.00	5,204.95	270.55	312.88	5,162.62	6.56570%	8.50000%	6,683.56	270.55	6,954.11	8.84408%	30-Dec-95
31-Dec-95	30,700,000.00	2,000,000.00	28,700,000.00	5,204.95	270.55	312.88	5,162.62	6.56570%	8.50000%	6,683.56	270.55	6,954.11	8.84408%	31-Dec-95
				88,952.55	8,386.99	938.64	96,400.90			126,391.78	8,386.99	134,778.77		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)	
30,700,000.00		28,700,000.00	MAXIMUM OUTSTANDING DURING MONTH
11,400,000.00		11,400,000.00	MINIMUM OUTSTANDING DURING MONTH
17,396,774.19	193,548.39	17,203,225.81	MONTH-TO-DATE AVERAGE OUTSTANDING
		96,400.90	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)
6.5880%	-5.7100%	6.5978%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)
6.0203%		6.0238%	ABOVE RATES NET OF COMMITMENT FEES

17,203,225.81
134,778.77
9.2245% (5)

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JANUARY 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jan-96	30,700,000.00	2,000,000.00	28,700,000.00	5,204.95	270.55	312.88	5,162.62	6.56570%	8.50000%	6,683.56	270.55	6,954.11	8.84408%	01-Jan-96
02-Jan-96	37,200,000.00	0.00	37,200,000.00	6,084.10	270.55	0.00	6,354.65	6.23507%	8.50000%	8,663.01	270.55	8,933.56	8.76546%	02-Jan-96
03-Jan-96	35,800,000.00	0.00	35,800,000.00	6,120.83	270.55	0.00	6,391.38	6.51635%	8.50000%	8,336.99	270.55	8,607.53	8.77584%	03-Jan-96
04-Jan-96	33,200,000.00	0.00	33,200,000.00	5,443.13	270.55	0.00	5,713.68	6.28160%	8.50000%	7,731.51	270.55	8,002.05	8.79744%	04-Jan-96
05-Jan-96	32,500,000.00	0.00	32,500,000.00	5,101.74	270.55	0.00	5,372.29	6.03349%	8.50000%	7,568.49	270.55	7,839.04	8.80385%	05-Jan-96
06-Jan-96	32,500,000.00	0.00	32,500,000.00	5,101.74	270.55	0.00	5,372.29	6.03349%	8.50000%	7,568.49	270.55	7,839.04	8.80385%	06-Jan-96
07-Jan-96	32,500,000.00	0.00	32,500,000.00	5,101.74	270.55	0.00	5,372.29	6.03349%	8.50000%	7,568.49	270.55	7,839.04	8.80385%	07-Jan-96
08-Jan-96	29,100,000.00	0.00	29,100,000.00	4,822.99	270.55	0.00	5,093.54	6.38880%	8.50000%	6,776.71	270.55	7,047.26	8.83935%	08-Jan-96
09-Jan-96	27,400,000.00	0.00	27,400,000.00	4,395.58	270.55	0.00	4,666.13	6.21583%	8.50000%	6,380.82	270.55	6,651.37	8.86040%	09-Jan-96
10-Jan-96	25,400,000.00	0.00	25,400,000.00	3,956.05	270.55	0.00	4,226.60	6.07365%	8.50000%	5,915.07	270.55	6,185.62	8.88878%	10-Jan-96
11-Jan-96	23,900,000.00	0.00	23,900,000.00	3,721.77	270.55	0.00	3,992.32	6.09705%	8.50000%	5,565.75	270.55	5,836.30	8.91318%	11-Jan-96
12-Jan-96	20,300,000.00	0.00	20,300,000.00	3,179.05	270.55	0.00	3,449.60	6.20248%	8.50000%	4,727.40	270.55	4,997.95	8.98645%	12-Jan-96
13-Jan-96	20,300,000.00	0.00	20,300,000.00	3,179.05	270.55	0.00	3,449.60	6.20248%	8.50000%	4,727.40	270.55	4,997.95	8.98645%	13-Jan-96
14-Jan-96	20,300,000.00	0.00	20,300,000.00	3,179.05	270.55	0.00	3,449.60	6.20248%	8.50000%	4,727.40	270.55	4,997.95	8.98645%	14-Jan-96
15-Jan-96	20,300,000.00	0.00	20,300,000.00	3,179.05	270.55	0.00	3,449.60	6.20248%	8.50000%	4,727.40	270.55	4,997.95	8.98645%	15-Jan-96
16-Jan-96	18,500,000.00	0.00	18,500,000.00	3,024.37	270.55	0.00	3,294.92	6.50078%	8.50000%	4,308.22	270.55	4,578.77	9.03378%	16-Jan-96
17-Jan-96	16,300,000.00	0.00	16,300,000.00	2,796.90	270.55	0.00	3,067.45	6.86883%	8.50000%	3,795.89	270.55	4,066.44	9.10583%	17-Jan-96
18-Jan-96	13,200,000.00	0.00	13,200,000.00	2,094.04	270.55	0.00	2,364.59	6.53844%	8.50000%	3,073.97	270.55	3,344.52	9.24811%	18-Jan-96
19-Jan-96	11,500,000.00	0.00	11,500,000.00	1,791.70	270.55	0.00	2,062.25	6.54540%	8.50000%	2,678.08	270.55	2,948.63	9.35870%	19-Jan-96
20-Jan-96	11,500,000.00	0.00	11,500,000.00	1,791.70	270.55	0.00	2,062.25	6.54540%	8.50000%	2,678.08	270.55	2,948.63	9.35870%	20-Jan-96
21-Jan-96	11,500,000.00	0.00	11,500,000.00	1,791.70	270.55	0.00	2,062.25	6.54540%	8.50000%	2,678.08	270.55	2,948.63	9.35870%	21-Jan-96
22-Jan-96	12,400,000.00	0.00	12,400,000.00	1,933.65	270.55	0.00	2,204.20	6.48816%	8.50000%	2,887.67	270.55	3,158.22	9.29637%	22-Jan-96
23-Jan-96	11,500,000.00	0.00	11,500,000.00	1,789.73	270.55	0.00	2,060.28	6.53914%	8.50000%	2,678.08	270.55	2,948.63	9.35870%	23-Jan-96
24-Jan-96	13,000,000.00	0.00	13,000,000.00	2,017.71	270.55	0.00	2,288.26	6.42472%	8.50000%	3,027.40	270.55	3,297.95	9.25962%	24-Jan-96
25-Jan-96	17,000,000.00	0.00	17,000,000.00	2,687.85	270.55	0.00	2,958.40	6.35185%	8.50000%	3,958.90	270.55	4,229.45	9.08088%	25-Jan-96
26-Jan-96	18,000,000.00	0.00	18,000,000.00	2,863.04	270.55	0.00	3,133.59	6.35422%	8.50000%	4,191.78	270.55	4,462.33	9.04861%	26-Jan-96
27-Jan-96	18,000,000.00	0.00	18,000,000.00	2,863.04	270.55	0.00	3,133.59	6.35422%	8.50000%	4,191.78	270.55	4,462.33	9.04861%	27-Jan-96
28-Jan-96	18,000,000.00	0.00	18,000,000.00	2,863.04	270.55	0.00	3,133.59	6.35422%	8.50000%	4,191.78	270.55	4,462.33	9.04861%	28-Jan-96
29-Jan-96	17,400,000.00	0.00	17,400,000.00	2,776.67	270.55	0.00	3,047.22	6.39215%	8.50000%	4,052.05	270.55	4,322.60	9.06753%	29-Jan-96
30-Jan-96	15,000,000.00	0.00	15,000,000.00	2,378.82	270.55	0.00	2,649.37	6.44680%	8.50000%	3,493.15	270.55	3,763.70	9.15833%	30-Jan-96
31-Jan-96	30,400,000.00	0.00	30,400,000.00	4,977.30	270.55	0.00	5,247.85	6.30087%	8.50000%	7,079.45	270.55	7,350.00	8.82484%	31-Jan-96
				108,212.08	8,386.99	312.88	116,286.19			156,632.88	8,386.99	165,019.87		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE
37,200,000.00		37,200,000.00	MAXIMUM OUTSTANDING DURING MONTH	
11,500,000.00		11,500,000.00	MINIMUM OUTSTANDING DURING MONTH	
21,761,290.32	64,516.13	21,696,774.19	MONTH-TO-DATE AVERAGE OUTSTANDING	21,696,774.19
		116,286.19	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	165,019.87
6.3087%	-5.7101%	6.3105%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.9551% (5)
5.8549%		5.8554%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: FEBRUARY 29, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Feb-96	31,000,000.00	0.00	31,000,000.00	4,782.81	270.55	0.00	5,053.36	5.94992%	8.25000%	7,006.85	270.55	7,277.40	8.56855%	01-Feb-96
02-Feb-96	30,500,000.00	0.00	30,500,000.00	4,680.91	270.55	0.00	4,951.46	5.92552%	8.25000%	6,893.84	270.55	7,164.38	8.57377%	02-Feb-96
03-Feb-96	30,500,000.00	0.00	30,500,000.00	4,680.91	270.55	0.00	4,951.46	5.92552%	8.25000%	6,893.84	270.55	7,164.38	8.57377%	03-Feb-96
04-Feb-96	30,500,000.00	0.00	30,500,000.00	4,680.91	270.55	0.00	4,951.46	5.92552%	8.25000%	6,893.84	270.55	7,164.38	8.57377%	04-Feb-96
05-Feb-96	30,300,000.00	0.00	30,300,000.00	4,648.93	270.55	0.00	4,919.48	5.92610%	8.25000%	6,848.63	270.55	7,119.18	8.57591%	05-Feb-96
06-Feb-96	28,000,000.00	0.00	28,000,000.00	4,292.78	270.55	0.00	4,563.33	5.94862%	8.25000%	6,328.77	270.55	6,599.32	8.60268%	06-Feb-96
07-Feb-96	23,400,000.00	0.00	23,400,000.00	3,491.94	270.55	0.00	3,762.49	5.86884%	8.25000%	5,289.04	270.55	5,559.59	8.67201%	07-Feb-96
08-Feb-96	18,500,000.00	0.00	18,500,000.00	2,739.16	270.55	0.00	3,009.71	5.93807%	8.25000%	4,181.51	270.55	4,452.05	8.78378%	08-Feb-96
09-Feb-96	15,200,000.00	0.00	15,200,000.00	2,249.31	270.55	0.00	2,519.86	6.05098%	8.25000%	3,435.62	270.55	3,706.16	8.89967%	09-Feb-96
10-Feb-96	15,200,000.00	0.00	15,200,000.00	2,249.31	270.55	0.00	2,519.86	6.05098%	8.25000%	3,435.62	270.55	3,706.16	8.89967%	10-Feb-96
11-Feb-96	15,200,000.00	0.00	15,200,000.00	2,249.31	270.55	0.00	2,519.86	6.05098%	8.25000%	3,435.62	270.55	3,706.16	8.89967%	11-Feb-96
12-Feb-96	12,700,000.00	0.00	12,700,000.00	1,918.53	270.55	0.00	2,189.08	6.29144%	8.25000%	2,870.55	270.55	3,141.10	9.02756%	12-Feb-96
13-Feb-96	9,900,000.00	0.00	9,900,000.00	1,462.66	270.55	0.00	1,733.21	6.39011%	8.25000%	2,237.67	270.55	2,508.22	9.24748%	13-Feb-96
14-Feb-96	6,100,000.00	0.00	6,100,000.00	933.00	270.55	0.00	1,203.55	7.20156%	8.25000%	1,378.77	270.55	1,649.32	9.86885%	14-Feb-96
15-Feb-96	3,800,000.00	0.00	3,800,000.00	594.41	270.55	0.00	864.96	8.30815%	8.25000%	858.90	270.55	1,129.45	10.84869%	15-Feb-96
16-Feb-96	4,500,000.00	0.00	4,500,000.00	664.84	270.55	0.00	935.39	7.58704%	8.25000%	1,017.12	270.55	1,287.67	10.44445%	16-Feb-96
17-Feb-96	4,500,000.00	0.00	4,500,000.00	664.84	270.55	0.00	935.39	7.58704%	8.25000%	1,017.12	270.55	1,287.67	10.44445%	17-Feb-96
18-Feb-96	4,500,000.00	0.00	4,500,000.00	664.84	270.55	0.00	935.39	7.58704%	8.25000%	1,017.12	270.55	1,287.67	10.44445%	18-Feb-96
19-Feb-96	4,500,000.00	0.00	4,500,000.00	664.84	270.55	0.00	935.39	7.58704%	8.25000%	1,017.12	270.55	1,287.67	10.44445%	19-Feb-96
20-Feb-96	1,300,000.00	0.00	1,300,000.00	194.32	270.55	0.00	464.87	13.05207%	8.25000%	293.84	270.55	564.38	15.84616%	20-Feb-96
21-Feb-96	0.00	1,600,000.00	(1,600,000.00)	0.00	270.55	233.64	36.90	N.A.	8.25000%	0.00	270.55	36.90	N/A	21-Feb-96
22-Feb-96	1,700,000.00	0.00	1,700,000.00	250.75	270.55	0.00	521.30	11.19258%	8.25000%	384.25	270.55	654.79	14.05883%	22-Feb-96
23-Feb-96	1,900,000.00	0.00	1,900,000.00	283.42	270.55	0.00	553.97	10.64202%	8.25000%	429.45	270.55	700.00	13.44737%	23-Feb-96
24-Feb-96	1,900,000.00	0.00	1,900,000.00	283.42	270.55	0.00	553.97	10.64202%	8.25000%	429.45	270.55	700.00	13.44737%	24-Feb-96
25-Feb-96	1,900,000.00	0.00	1,900,000.00	283.42	270.55	0.00	553.97	10.64202%	8.25000%	429.45	270.55	700.00	13.44737%	25-Feb-96
26-Feb-96	4,000,000.00	0.00	4,000,000.00	596.67	270.55	0.00	867.22	7.91337%	8.25000%	904.11	270.55	1,174.66	10.71875%	26-Feb-96
27-Feb-96	3,500,000.00	0.00	3,500,000.00	522.08	270.55	0.00	792.63	8.26598%	8.25000%	791.10	270.55	1,061.64	11.07143%	27-Feb-96
28-Feb-96	3,600,000.00	0.00	3,600,000.00	556.00	270.55	0.00	826.55	8.38028%	8.25000%	813.70	270.55	1,084.25	10.99306%	28-Feb-96
29-Feb-96	20,500,000.00	0.00	20,500,000.00	3,240.87	270.55	0.00	3,511.42	6.25204%	8.25000%	4,633.56	270.55	4,904.11	8.73171%	29-Feb-96
				54,525.19	7,845.89	233.64	62,137.44			81,166.44	7,845.89	88,778.69		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE @ NBANK PRIME	
31,000,000.00		31,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(1,600,000.00)	MINIMUM OUTSTANDING DURING MONTH		
12,382,758.62	55,172.41	12,327,586.21	MONTH-TO-DATE AVERAGE OUTSTANDING	12,382,758.62	
		62,137.44	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	88,778.69	
6.3396%	-5.3300%	6.3441%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	9.0237%	(5)
5.5421%		5.5431%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: March 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Mar-96	21,600,000.00	0.00	21,600,000.00	3,356.66	270.55	0.00	3,627.21	6.12931%	8.25000%	4,882.19	270.55	5,152.74	8.70718%	01-Mar-96
02-Mar-96	21,600,000.00	0.00	21,600,000.00	3,356.66	270.55	0.00	3,627.21	6.12931%	8.25000%	4,882.19	270.55	5,152.74	8.70718%	02-Mar-96
03-Mar-96	21,600,000.00	0.00	21,600,000.00	3,356.66	270.55	0.00	3,627.21	6.12931%	8.25000%	4,882.19	270.55	5,152.74	8.70718%	03-Mar-96
04-Mar-96	18,800,000.00	0.00	18,800,000.00	2,892.42	270.55	0.00	3,162.97	6.14087%	8.25000%	4,249.32	270.55	4,519.86	8.77527%	04-Mar-96
05-Mar-96	17,800,000.00	0.00	17,800,000.00	2,707.52	270.55	0.00	2,978.07	6.10671%	8.25000%	4,023.29	270.55	4,293.84	8.80478%	05-Mar-96
06-Mar-96	12,600,000.00	0.00	12,600,000.00	1,885.83	270.55	0.00	2,156.38	6.24665%	8.25000%	2,847.95	270.55	3,118.49	9.03373%	06-Mar-96
07-Mar-96	8,300,000.00	0.00	8,300,000.00	1,229.64	270.55	0.00	1,500.19	6.59721%	8.25000%	1,876.03	270.55	2,146.58	9.43976%	07-Mar-96
08-Mar-96	9,100,000.00	0.00	9,100,000.00	1,364.39	270.55	0.00	1,634.94	6.55772%	8.25000%	2,056.85	270.55	2,327.40	9.33517%	08-Mar-96
09-Mar-96	9,100,000.00	0.00	9,100,000.00	1,364.39	270.55	0.00	1,634.94	6.55772%	8.25000%	2,056.85	270.55	2,327.40	9.33517%	09-Mar-96
10-Mar-96	9,100,000.00	0.00	9,100,000.00	1,364.39	270.55	0.00	1,634.94	6.55772%	8.25000%	2,056.85	270.55	2,327.40	9.33517%	10-Mar-96
11-Mar-96	4,500,000.00	0.00	4,500,000.00	678.75	270.55	0.00	949.30	7.69986%	8.25000%	1,017.12	270.55	1,287.67	10.44445%	11-Mar-96
12-Mar-96	2,300,000.00	0.00	2,300,000.00	346.92	270.55	0.00	617.47	9.79895%	8.25000%	519.86	270.55	790.41	12.54348%	12-Mar-96
13-Mar-96	1,900,000.00	0.00	1,900,000.00	299.78	270.55	0.00	570.33	10.95630%	8.25000%	429.45	270.55	700.00	13.44737%	13-Mar-96
14-Mar-96	300,000.00	0.00	300,000.00	45.75	270.55	0.00	316.30	38.48293%	8.25000%	67.81	270.55	338.36	41.16668%	14-Mar-96
15-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	117.48	153.07	N.A.	8.25000%	0.00	270.55	153.07	N/A	15-Mar-96
16-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	117.48	153.07	N.A.	8.25000%	0.00	270.55	153.07	N/A	16-Mar-96
17-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	117.48	153.07	N.A.	8.25000%	0.00	270.55	153.07	N/A	17-Mar-96
18-Mar-96	500,000.00	0.00	500,000.00	76.25	270.55	0.00	346.80	25.31626%	8.25000%	113.01	270.55	383.56	28.00001%	18-Mar-96
19-Mar-96	0.00	0.00	0.00	0.00	270.55	0.00	270.55	N.A.	8.25000%	0.00	270.55	270.55	N/A	19-Mar-96
20-Mar-96	400,000.00	0.00	400,000.00	59.67	270.55	0.00	330.22	30.13240%	8.25000%	90.41	270.55	360.96	32.93751%	20-Mar-96
21-Mar-96	0.00	2,500,000.00	(2,500,000.00)	0.00	270.55	361.64	(91.10)	-1.33000%	8.25000%	0.00	270.55	(91.10)	N/A	21-Mar-96
22-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	115.29	155.26	N.A.	8.25000%	0.00	270.55	155.26	N/A	22-Mar-96
23-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	115.29	155.26	N.A.	8.25000%	0.00	270.55	155.26	N/A	23-Mar-96
24-Mar-96	0.00	800,000.00	(800,000.00)	0.00	270.55	115.29	155.26	N.A.	8.25000%	0.00	270.55	155.26	N/A	24-Mar-96
25-Mar-96	1,800,000.00	0.00	1,800,000.00	271.50	270.55	0.00	542.05	10.99153%	8.25000%	406.85	270.55	677.40	13.73611%	25-Mar-96
26-Mar-96	1,700,000.00	0.00	1,700,000.00	256.42	270.55	0.00	526.97	11.31431%	8.25000%	384.25	270.55	654.79	14.05883%	26-Mar-96
27-Mar-96	0.00	600,000.00	(600,000.00)	0.00	270.55	87.29	183.26	N.A.	8.25000%	0.00	270.55	183.26	N/A	27-Mar-96
28-Mar-96	200,000.00	0.00	200,000.00	31.39	270.55	0.00	301.94	55.10370%	8.25000%	45.21	270.55	315.75	57.62503%	28-Mar-96
29-Mar-96	16,100,000.00	2,000,000.00	14,100,000.00	2,531.93	270.55	290.41	2,512.07	6.50287%	8.25000%	3,186.99	270.55	3,457.53	8.95035%	29-Mar-96
30-Mar-96	16,100,000.00	2,000,000.00	14,100,000.00	2,531.93	270.55	290.41	2,512.07	6.50287%	8.25000%	3,186.99	270.55	3,457.53	8.95035%	30-Mar-96
31-Mar-96	16,100,000.00	2,000,000.00	14,100,000.00	2,531.93	270.55	290.41	2,512.07	6.50287%	8.25000%	3,186.99	270.55	3,457.53	8.95035%	31-Mar-96
				32,540.78	8,386.99	2,018.47	38,909.30			46,448.63	8,386.99	53,688.38		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
21,600,000.00		21,600,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(2,500,000.00)	MINIMUM OUTSTANDING DURING MONTH		
6,822,580.65	448,387.10	6,374,193.55	MONTH-TO-DATE AVERAGE OUTSTANDING	6,629,032.26	
		38,909.30	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	53,688.38	
7.0632%	-5.3003%	7.1872%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	9.5359%	(5)
5.6158%		5.6380%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS GMJ
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: APRIL 30, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Apr-96	16,100,000.00	0.00	16,100,000.00	2,499.85	270.55	0.00	2,770.40	6.28072%	8.25000%	3,639.04	270.55	3,909.59	8.86335%	01-Apr-96
02-Apr-96	15,100,000.00	0.00	15,100,000.00	2,339.82	270.55	0.00	2,610.37	6.30983%	8.25000%	3,413.01	270.55	3,683.56	8.90397%	02-Apr-96
03-Apr-96	13,100,000.00	0.00	13,100,000.00	2,005.63	270.55	0.00	2,276.18	6.34202%	8.25000%	2,960.96	270.55	3,231.51	9.00382%	03-Apr-96
04-Apr-96	9,000,000.00	0.00	9,000,000.00	1,361.11	270.55	0.00	1,631.66	6.61728%	8.25000%	2,034.25	270.55	2,304.79	9.34722%	04-Apr-96
05-Apr-96	7,200,000.00	0.00	7,200,000.00	1,073.76	270.55	0.00	1,344.31	6.81490%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	05-Apr-96
06-Apr-96	7,200,000.00	0.00	7,200,000.00	1,073.76	270.55	0.00	1,344.31	6.81490%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	06-Apr-96
07-Apr-96	7,200,000.00	0.00	7,200,000.00	1,073.76	270.55	0.00	1,344.31	6.81490%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	07-Apr-96
08-Apr-96	6,700,000.00	0.00	6,700,000.00	1,012.12	270.55	0.00	1,282.67	6.98767%	8.25000%	1,514.38	270.55	1,784.93	9.72388%	08-Apr-96
09-Apr-96	4,900,000.00	0.00	4,900,000.00	739.08	270.55	0.00	1,009.63	7.52070%	8.25000%	1,107.53	270.55	1,378.08	10.25531%	09-Apr-96
10-Apr-96	1,700,000.00	0.00	1,700,000.00	262.56	270.55	0.00	533.11	11.44614%	8.25000%	384.25	270.55	654.79	14.05883%	10-Apr-96
11-Apr-96	0.00	2,500,000.00	(2,500,000.00)	0.00	270.55	359.59	(89.04)	-1.30000%	8.25000%	0.00	270.55	(89.04)	N/A	11-Apr-96
12-Apr-96	0.00	4,900,000.00	(4,900,000.00)	0.00	270.55	704.79	(434.25)	-3.23469%	8.25000%	0.00	270.55	(434.25)	N/A	12-Apr-96
13-Apr-96	0.00	4,900,000.00	(4,900,000.00)	0.00	270.55	704.79	(434.24)	-3.23466%	8.25000%	0.00	270.55	(434.24)	N/A	13-Apr-96
14-Apr-96	0.00	4,900,000.00	(4,900,000.00)	0.00	270.55	704.79	(434.24)	-3.23466%	8.25000%	0.00	270.55	(434.24)	N/A	14-Apr-96
15-Apr-96	0.00	2,900,000.00	(2,900,000.00)	0.00	270.55	416.33	(145.78)	-1.83483%	8.25000%	0.00	270.55	(145.78)	N/A	15-Apr-96
16-Apr-96	0.00	4,000,000.00	(4,000,000.00)	0.00	270.55	572.05	(301.51)	-2.75125%	8.25000%	0.00	270.55	(301.51)	N/A	16-Apr-96
17-Apr-96	0.00	6,600,000.00	(6,600,000.00)	0.00	270.55	944.33	(673.78)	-3.72621%	8.25000%	0.00	270.55	(673.78)	N/A	17-Apr-96
18-Apr-96	0.00	7,500,000.00	(7,500,000.00)	0.00	270.55	1,074.66	(804.11)	-3.91333%	8.25000%	0.00	270.55	(804.11)	N/A	18-Apr-96
19-Apr-96	0.00	4,700,000.00	(4,700,000.00)	0.00	270.55	673.45	(402.90)	-3.12894%	8.25000%	0.00	270.55	(402.90)	N/A	19-Apr-96
20-Apr-96	0.00	4,700,000.00	(4,700,000.00)	0.00	270.55	673.45	(402.90)	-3.12892%	8.25000%	0.00	270.55	(402.90)	N/A	20-Apr-96
21-Apr-96	0.00	4,700,000.00	(4,700,000.00)	0.00	270.55	673.45	(402.90)	-3.12892%	8.25000%	0.00	270.55	(402.90)	N/A	21-Apr-96
22-Apr-96	200,000.00	0.00	200,000.00	29.83	270.55	0.00	300.38	54.81900%	8.25000%	45.21	270.55	315.75	57.62503%	22-Apr-96
23-Apr-96	0.00	1,000,000.00	(1,000,000.00)	0.00	270.55	143.29	127.26	N.A.	8.25000%	0.00	270.55	127.26	N/A	23-Apr-96
24-Apr-96	0.00	3,700,000.00	(3,700,000.00)	0.00	270.55	532.19	(261.64)	-2.58108%	8.25000%	0.00	270.55	(261.64)	N/A	24-Apr-96
25-Apr-96	400,000.00	0.00	400,000.00	60.00	270.55	0.00	330.55	30.16251%	8.25000%	90.41	270.55	360.96	32.93751%	25-Apr-96
26-Apr-96	2,000,000.00	0.00	2,000,000.00	298.33	270.55	0.00	568.88	10.38203%	8.25000%	452.05	270.55	722.60	13.18750%	26-Apr-96
27-Apr-96	2,000,000.00	0.00	2,000,000.00	298.33	270.55	0.00	568.88	10.38203%	8.25000%	452.05	270.55	722.60	13.18750%	27-Apr-96
28-Apr-96	2,000,000.00	0.00	2,000,000.00	298.33	270.55	0.00	568.88	10.38203%	8.25000%	452.05	270.55	722.60	13.18750%	28-Apr-96
29-Apr-96	1,200,000.00	0.00	1,200,000.00	181.00	270.55	0.00	451.55	13.73459%	8.25000%	271.23	270.55	541.78	16.47917%	29-Apr-96
30-Apr-96	23,100,000.00	0.00	23,100,000.00	3,585.80	270.55	0.00	3,856.35	6.09336%	8.25000%	5,221.23	270.55	5,491.78	8.67749%	30-Apr-96
				18,193.07	8,116.44	8,177.16	18,132.35			26,919.86	8,116.44	26,859.14		

23,100,000.00		23,100,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		(7,500,000.00)	MINIMUM OUTSTANDING DURING MONTH		
3,970,000.00	1,900,000.00	2,070,000.00	MONTH-TO-DATE AVERAGE OUTSTANDING	3,970,000.00	
		18,132.35	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	26,859.14	
8.0629%	-5.2363%	10.6575%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.2314%	(5)
5.5755%		5.8870%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: MAY 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-May-96	23,100,000.00	0.00	23,100,000.00	3,546.26	270.55	0.00	3,816.81	6.03089%	8.25000%	5,221.23	270.55	5,491.78	8.67749%	01-May-96
02-May-96	20,200,000.00	0.00	20,200,000.00	3,088.29	270.55	0.00	3,358.84	6.06919%	8.25000%	4,565.75	270.55	4,836.30	8.73886%	02-May-96
03-May-96	19,300,000.00	0.00	19,300,000.00	2,890.83	270.55	0.00	3,161.38	5.97877%	8.25000%	4,362.33	270.55	4,632.88	8.76166%	03-May-96
04-May-96	19,300,000.00	0.00	19,300,000.00	2,890.83	270.55	0.00	3,161.38	5.97877%	8.25000%	4,362.33	270.55	4,632.88	8.76166%	04-May-96
05-May-96	19,300,000.00	0.00	19,300,000.00	2,890.83	270.55	0.00	3,161.38	5.97877%	8.25000%	4,362.33	270.55	4,632.88	8.76166%	05-May-96
06-May-96	17,100,000.00	0.00	17,100,000.00	2,590.18	270.55	0.00	2,860.73	6.10623%	8.25000%	3,865.07	270.55	4,135.62	8.82749%	06-May-96
07-May-96	15,200,000.00	0.00	15,200,000.00	2,310.75	270.55	0.00	2,581.30	6.19851%	8.25000%	3,435.62	270.55	3,706.16	8.89967%	07-May-96
08-May-96	12,900,000.00	0.00	12,900,000.00	2,012.08	270.55	0.00	2,282.63	6.45860%	8.25000%	2,915.75	270.55	3,186.30	9.01550%	08-May-96
09-May-96	8,900,000.00	0.00	8,900,000.00	1,345.94	270.55	0.00	1,616.49	6.62942%	8.25000%	2,011.64	270.55	2,282.19	9.35955%	09-May-96
10-May-96	7,200,000.00	0.00	7,200,000.00	1,075.83	270.55	0.00	1,346.38	6.82539%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	10-May-96
11-May-96	7,200,000.00	0.00	7,200,000.00	1,075.83	270.55	0.00	1,346.38	6.82539%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	11-May-96
12-May-96	7,200,000.00	0.00	7,200,000.00	1,075.83	270.55	0.00	1,346.38	6.82539%	8.25000%	1,627.40	270.55	1,897.95	9.62153%	12-May-96
13-May-96	4,900,000.00	0.00	4,900,000.00	758.49	245.38	0.00	1,003.87	7.47779%	8.25000%	1,107.53	245.38	1,352.91	10.07782%	13-May-96
14-May-96	1,300,000.00	0.00	1,300,000.00	196.08	270.55	0.00	466.63	13.10148%	8.25000%	293.84	270.55	564.38	15.84616%	14-May-96
15-May-96	0.00	600,000.00	(600,000.00)	0.00	270.55	85.97	184.58	N.A.	8.25000%	0.00	270.55	184.58	N/A	15-May-96
16-May-96	0.00	700,000.00	(700,000.00)	0.00	270.55	100.30	170.25	N.A.	8.25000%	0.00	270.55	170.25	N/A	16-May-96
17-May-96	0.00	100,000.00	(100,000.00)	0.00	270.55	14.30	256.25	N.A.	8.25000%	0.00	270.55	256.25	N/A	17-May-96
18-May-96	0.00	100,000.00	(100,000.00)	0.00	270.55	14.30	256.25	N.A.	8.25000%	0.00	270.55	256.25	N/A	18-May-96
19-May-96	0.00	100,000.00	(100,000.00)	0.00	270.55	14.30	256.25	N.A.	8.25000%	0.00	270.55	256.25	N/A	19-May-96
20-May-96	3,800,000.00	0.00	3,800,000.00	573.17	270.55	0.00	843.72	8.10413%	8.25000%	858.90	270.55	1,129.45	10.84869%	20-May-96
21-May-96	3,500,000.00	0.00	3,500,000.00	522.08	270.55	0.00	792.63	8.26598%	8.25000%	791.10	270.55	1,061.64	11.07143%	21-May-96
22-May-96	3,600,000.00	0.00	3,600,000.00	562.00	270.55	0.00	832.55	8.44111%	8.25000%	813.70	270.55	1,084.25	10.99306%	22-May-96
23-May-96	3,400,000.00	0.00	3,400,000.00	507.17	270.55	0.00	777.72	8.34903%	8.25000%	768.49	270.55	1,039.04	11.15441%	23-May-96
24-May-96	3,400,000.00	0.00	3,400,000.00	501.50	270.55	0.00	772.05	8.28816%	8.25000%	768.49	270.55	1,039.04	11.15441%	24-May-96
25-May-96	3,400,000.00	0.00	3,400,000.00	501.50	270.55	0.00	772.05	8.28816%	8.25000%	768.49	270.55	1,039.04	11.15441%	25-May-96
26-May-96	3,400,000.00	0.00	3,400,000.00	501.50	270.55	0.00	772.05	8.28816%	8.25000%	768.49	270.55	1,039.04	11.15441%	26-May-96
27-May-96	3,400,000.00	0.00	3,400,000.00	501.50	270.55	0.00	772.05	8.28816%	8.25000%	768.49	270.55	1,039.04	11.15441%	27-May-96
28-May-96	8,500,000.00	0.00	8,500,000.00	1,301.78	226.89	0.00	1,528.67	6.56428%	8.25000%	1,921.23	226.89	2,148.12	9.22428%	28-May-96
29-May-96	7,900,000.00	0.00	7,900,000.00	1,194.20	270.55	0.00	1,464.75	6.76751%	8.25000%	1,785.62	270.55	2,056.16	9.50000%	29-May-96
30-May-96	6,500,000.00	0.00	6,500,000.00	1,006.16	237.16	0.00	1,243.32	6.98171%	8.25000%	1,469.18	237.16	1,706.34	9.58173%	30-May-96
31-May-96	19,100,000.00	0.00	19,100,000.00	3,047.59	219.18	0.00	3,266.77	6.24278%	8.25000%	4,317.12	219.18	4,536.30	8.66885%	31-May-96
				38,468.20	8,233.40	229.18	46,472.43			57,184.93	8,233.40	65,189.16		

23,100,000.00		23,100,000.00	MAXIMUM OUTSTANDING DURING MONTH	
0.00		(700,000.00)	MINIMUM OUTSTANDING DURING MONTH	
8,161,290.32	51,612.90	8,109,677.42	MONTH-TO-DATE AVERAGE OUTSTANDING	8,161,290.32
		46,472.43	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	65,189.16
6.7376%	-5.2281%	6.7472%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	9.4048% (5)
5.5498%		5.5518%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JUNE 28, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jun-96	19,100,000.00	0.00	19,100,000.00	3,047.59	219.18	0.00	3,266.77	6.24278%	8.25000%	4,317.12	219.18	4,536.30	8.66885%	01-Jun-96
02-Jun-96	19,100,000.00	0.00	19,100,000.00	3,047.59	219.18	0.00	3,266.77	6.24278%	8.25000%	4,317.12	219.18	4,536.30	8.66885%	02-Jun-96
03-Jun-96	19,400,000.00	0.00	19,400,000.00	3,007.22	270.55	0.00	3,277.77	6.16693%	8.25000%	4,384.93	270.55	4,655.48	8.75902%	03-Jun-96
04-Jun-96	18,700,000.00	0.00	18,700,000.00	2,853.20	270.55	0.00	3,123.75	6.09716%	8.25000%	4,226.71	270.55	4,497.26	8.77808%	04-Jun-96
05-Jun-96	17,900,000.00	0.00	17,900,000.00	2,796.80	270.55	0.00	3,067.35	6.25465%	8.25000%	4,045.89	270.55	4,316.44	8.80168%	05-Jun-96
06-Jun-96	11,400,000.00	0.00	11,400,000.00	1,730.85	270.55	0.00	2,001.40	6.40799%	8.25000%	2,576.71	270.55	2,847.26	9.11623%	06-Jun-96
07-Jun-96	14,000,000.00	0.00	14,000,000.00	2,095.83	270.55	0.00	2,366.38	6.16949%	8.25000%	3,164.38	270.55	3,434.93	8.95536%	07-Jun-96
08-Jun-96	14,000,000.00	0.00	14,000,000.00	2,095.83	270.55	0.00	2,366.38	6.16949%	8.25000%	3,164.38	270.55	3,434.93	8.95536%	08-Jun-96
09-Jun-96	14,000,000.00	0.00	14,000,000.00	2,095.83	270.55	0.00	2,366.38	6.16949%	8.25000%	3,164.38	270.55	3,434.93	8.95536%	09-Jun-96
10-Jun-96	12,800,000.00	0.00	12,800,000.00	1,976.53	230.48	0.00	2,207.01	6.29342%	8.25000%	2,893.15	230.48	3,123.63	8.90722%	10-Jun-96
11-Jun-96	9,900,000.00	0.00	9,900,000.00	1,480.83	270.55	0.00	1,751.38	6.45710%	8.25000%	2,237.67	270.55	2,508.22	9.24748%	11-Jun-96
12-Jun-96	6,200,000.00	0.00	6,200,000.00	959.73	238.70	0.00	1,198.43	7.05526%	8.25000%	1,401.37	238.70	1,640.07	9.65524%	12-Jun-96
13-Jun-96	4,200,000.00	0.00	4,200,000.00	633.50	270.55	0.00	904.05	7.85661%	8.25000%	949.32	270.55	1,219.86	10.60119%	13-Jun-96
14-Jun-96	5,400,000.00	0.00	5,400,000.00	814.55	270.55	0.00	1,085.10	7.33446%	8.25000%	1,220.55	270.55	1,491.10	10.07870%	14-Jun-96
15-Jun-96	5,400,000.00	0.00	5,400,000.00	814.55	270.55	0.00	1,085.10	7.33446%	8.25000%	1,220.55	270.55	1,491.10	10.07870%	15-Jun-96
16-Jun-96	5,400,000.00	0.00	5,400,000.00	814.55	270.55	0.00	1,085.10	7.33446%	8.25000%	1,220.55	270.55	1,491.10	10.07870%	16-Jun-96
17-Jun-96	8,200,000.00	0.00	8,200,000.00	1,274.44	270.55	0.00	1,544.99	6.87708%	8.25000%	1,853.42	270.55	2,123.97	9.45427%	17-Jun-96
18-Jun-96	8,400,000.00	0.00	8,400,000.00	1,284.31	270.55	0.00	1,554.86	6.75623%	8.25000%	1,898.63	270.55	2,169.18	9.42560%	18-Jun-96
19-Jun-96	7,400,000.00	0.00	7,400,000.00	1,171.84	232.54	0.00	1,404.38	6.92700%	8.25000%	1,672.60	232.54	1,905.14	9.39698%	19-Jun-96
20-Jun-96	7,800,000.00	0.00	7,800,000.00	1,194.66	270.55	0.00	1,465.21	6.85642%	8.25000%	1,763.01	270.55	2,033.56	9.51603%	20-Jun-96
21-Jun-96	7,900,000.00	0.00	7,900,000.00	1,191.87	270.55	0.00	1,462.42	6.75674%	8.25000%	1,785.62	270.55	2,056.16	9.50000%	21-Jun-96
22-Jun-96	7,900,000.00	0.00	7,900,000.00	1,191.87	270.55	0.00	1,462.42	6.75674%	8.25000%	1,785.62	270.55	2,056.16	9.50000%	22-Jun-96
23-Jun-96	7,900,000.00	0.00	7,900,000.00	1,191.87	270.55	0.00	1,462.42	6.75674%	8.25000%	1,785.62	270.55	2,056.16	9.50000%	23-Jun-96
24-Jun-96	11,300,000.00	0.00	11,300,000.00	1,744.03	219.18	0.00	1,963.21	6.34134%	8.25000%	2,554.11	219.18	2,773.29	8.95796%	24-Jun-96
25-Jun-96	16,000,000.00	0.00	16,000,000.00	2,447.95	219.18	0.00	2,667.13	6.08439%	8.25000%	3,616.44	219.18	3,835.62	8.75000%	25-Jun-96
26-Jun-96	15,500,000.00	0.00	15,500,000.00	2,372.95	219.18	0.00	2,592.13	6.10404%	8.25000%	3,503.42	219.18	3,722.60	8.76613%	26-Jun-96
27-Jun-96	15,300,000.00	0.00	15,300,000.00	2,347.56	219.18	0.00	2,566.74	6.12326%	8.25000%	3,458.22	219.18	3,677.40	8.77268%	27-Jun-96
28-Jun-96	26,100,000.00	2,000,000.00	24,100,000.00	4,203.16	219.18	292.60	4,129.74	6.25458%	8.25000%	5,447.26	219.18	5,666.44	8.58195%	28-Jun-96
29-Jun-96	26,100,000.00	2,000,000.00	24,100,000.00	4,203.16	219.18	292.60	4,129.74	6.25458%	8.25000%	5,447.26	219.18	5,666.44	8.58195%	29-Jun-96
30-Jun-96	26,100,000.00	2,000,000.00	24,100,000.00	4,203.16	219.18	292.60	4,129.74	6.25458%	8.25000%	5,447.26	219.18	5,666.44	8.58195%	30-Jun-96
				60,287.81	7,544.18	877.80	66,954.19			86,523.29	7,544.18	94,067.47		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
26,100,000.00		24,100,000.00	MAXIMUM OUTSTANDING DURING MONTH		
4,200,000.00		4,200,000.00	MINIMUM OUTSTANDING DURING MONTH		
12,960,000.00	200,000.00	12,760,000.00	MONTH-TO-DATE AVERAGE OUTSTANDING	12,760,000.00	
		66,954.19	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	94,067.47	
6.3680%	-5.3400%	6.3841%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.9693%	(5)
5.6597%		5.6647%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS 2/7
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JULY 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jul-96	27,400,000.00	0.00	27,400,000.00	4,306.40	270.55	0.00	4,576.95	6.09703%	8.25000%	6,193.15	270.55	6,463.70	8.61040%	01-Jul-96
02-Jul-96	27,900,000.00	0.00	27,900,000.00	4,424.58	219.18	0.00	4,643.76	6.07517%	8.25000%	6,306.16	219.18	6,525.34	8.53674%	02-Jul-96
03-Jul-96	26,800,000.00	0.00	26,800,000.00	4,336.78	219.18	0.00	4,555.96	6.20494%	8.25000%	6,057.53	219.18	6,276.71	8.54851%	03-Jul-96
04-Jul-96	26,800,000.00	0.00	26,800,000.00	4,336.78	219.18	0.00	4,555.96	6.20494%	8.25000%	6,057.53	219.18	6,276.71	8.54851%	04-Jul-96
05-Jul-96	25,500,000.00	0.00	25,500,000.00	3,912.50	270.55	0.00	4,183.05	5.98750%	8.25000%	5,763.70	270.55	6,034.25	8.63726%	05-Jul-96
06-Jul-96	25,500,000.00	0.00	25,500,000.00	3,912.50	270.55	0.00	4,183.05	5.98750%	8.25000%	5,763.70	270.55	6,034.25	8.63726%	06-Jul-96
07-Jul-96	25,500,000.00	0.00	25,500,000.00	3,912.50	270.55	0.00	4,183.05	5.98750%	8.25000%	5,763.70	270.55	6,034.25	8.63726%	07-Jul-96
08-Jul-96	24,700,000.00	0.00	24,700,000.00	3,795.85	246.41	0.00	4,042.26	5.97338%	8.25000%	5,582.88	246.41	5,829.28	8.61413%	08-Jul-96
09-Jul-96	22,800,000.00	0.00	22,800,000.00	3,442.56	270.55	0.00	3,713.11	5.94423%	8.25000%	5,153.42	270.55	5,423.97	8.68311%	09-Jul-96
10-Jul-96	21,200,000.00	0.00	21,200,000.00	3,168.58	264.39	0.00	3,432.97	5.91053%	8.25000%	4,791.78	264.39	5,056.17	8.70520%	10-Jul-96
11-Jul-96	18,300,000.00	0.00	18,300,000.00	2,729.25	270.55	0.00	2,999.80	5.98320%	8.25000%	4,136.30	270.55	4,406.85	8.78962%	11-Jul-96
12-Jul-96	16,000,000.00	0.00	16,000,000.00	2,373.13	270.55	0.00	2,643.68	6.03089%	8.25000%	3,616.44	270.55	3,886.99	8.86719%	12-Jul-96
13-Jul-96	16,000,000.00	0.00	16,000,000.00	2,373.13	270.55	0.00	2,643.68	6.03089%	8.25000%	3,616.44	270.55	3,886.99	8.86719%	13-Jul-96
14-Jul-96	16,000,000.00	0.00	16,000,000.00	2,373.13	270.55	0.00	2,643.68	6.03089%	8.25000%	3,616.44	270.55	3,886.99	8.86719%	14-Jul-96
15-Jul-96	15,500,000.00	0.00	15,500,000.00	2,392.05	219.18	0.00	2,611.23	6.14902%	8.25000%	3,503.42	219.18	3,722.60	8.76613%	15-Jul-96
16-Jul-96	16,700,000.00	0.00	16,700,000.00	2,535.29	270.55	0.00	2,805.84	6.13252%	8.25000%	3,774.66	270.55	4,045.21	8.84132%	16-Jul-96
17-Jul-96	16,800,000.00	0.00	16,800,000.00	2,603.37	219.18	0.00	2,822.55	6.13232%	8.25000%	3,797.26	219.18	4,016.44	8.72619%	17-Jul-96
18-Jul-96	16,400,000.00	0.00	16,400,000.00	2,500.25	270.55	0.00	2,770.80	6.16672%	8.25000%	3,706.85	270.55	3,977.40	8.85213%	18-Jul-96
19-Jul-96	16,200,000.00	0.00	16,200,000.00	2,416.00	270.55	0.00	2,686.55	6.05303%	8.25000%	3,661.64	270.55	3,932.19	8.85957%	19-Jul-96
20-Jul-96	16,200,000.00	0.00	16,200,000.00	2,416.00	270.55	0.00	2,686.55	6.05303%	8.25000%	3,661.64	270.55	3,932.19	8.85957%	20-Jul-96
21-Jul-96	16,200,000.00	0.00	16,200,000.00	2,416.00	270.55	0.00	2,686.55	6.05303%	8.25000%	3,661.64	270.55	3,932.19	8.85957%	21-Jul-96
22-Jul-96	17,800,000.00	0.00	17,800,000.00	2,685.37	270.55	0.00	2,955.92	6.06129%	8.25000%	4,023.29	270.55	4,293.84	8.80478%	22-Jul-96
23-Jul-96	22,000,000.00	0.00	22,000,000.00	3,330.63	260.28	0.00	3,590.91	5.95764%	8.25000%	4,972.60	260.28	5,232.88	8.68183%	23-Jul-96
24-Jul-96	21,100,000.00	0.00	21,100,000.00	3,197.31	270.55	0.00	3,467.86	5.99890%	8.25000%	4,769.18	270.55	5,039.73	8.71801%	24-Jul-96
25-Jul-96	22,400,000.00	0.00	22,400,000.00	3,427.92	270.55	0.00	3,698.47	6.02652%	8.25000%	5,063.01	270.55	5,333.56	8.69085%	25-Jul-96
26-Jul-96	22,900,000.00	0.00	22,900,000.00	3,515.48	255.65	0.00	3,771.13	6.01075%	8.25000%	5,176.03	255.65	5,431.68	8.65747%	26-Jul-96
27-Jul-96	22,900,000.00	0.00	22,900,000.00	3,515.48	255.65	0.00	3,771.13	6.01075%	8.25000%	5,176.03	255.65	5,431.68	8.65747%	27-Jul-96
28-Jul-96	22,900,000.00	0.00	22,900,000.00	3,515.48	255.65	0.00	3,771.13	6.01075%	8.25000%	5,176.03	255.65	5,431.68	8.65747%	28-Jul-96
29-Jul-96	22,500,000.00	0.00	22,500,000.00	3,516.64	219.18	0.00	3,735.82	6.06033%	8.25000%	5,085.62	219.18	5,304.79	8.60556%	29-Jul-96
30-Jul-96	22,600,000.00	0.00	22,600,000.00	3,483.75	270.55	0.00	3,754.30	6.06336%	8.25000%	5,108.22	270.55	5,378.77	8.68695%	30-Jul-96
31-Jul-96	29,300,000.00	0.00	29,300,000.00	4,806.30	219.18	0.00	5,025.48	6.26041%	8.25000%	6,622.60	219.18	6,841.78	8.52304%	31-Jul-96
				101,670.99	7,942.13	0.00	109,613.12			149,358.90	7,942.13	157,301.03		

29,300,000.00		29,300,000.00	MAXIMUM OUTSTANDING DURING MONTH	
15,500,000.00		15,500,000.00	MINIMUM OUTSTANDING DURING MONTH	
21,316,129.03	0.00	21,316,129.03	MONTH-TO-DATE AVERAGE OUTSTANDING	21,316,129.03
		109,613.12	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	157,301.03
6.0546%	N.A.	6.0546%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.6887% (5)
5.6159%		5.6159%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: AUGUST 30, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Aug-96	32,200,000.00	0.00	32,200,000.00	5,148.54	219.18	0.00	5,367.72	6.08453%	8.25000%	7,278.08	219.18	7,497.26	8.49845%	01-Aug-96
02-Aug-96	33,000,000.00	0.00	33,000,000.00	5,360.50	219.18	0.00	5,579.68	6.17146%	8.25000%	7,458.90	219.18	7,678.08	8.49242%	02-Aug-96
03-Aug-96	33,000,000.00	0.00	33,000,000.00	5,360.50	219.18	0.00	5,579.68	6.17146%	8.25000%	7,458.90	219.18	7,678.08	8.49242%	03-Aug-96
04-Aug-96	33,000,000.00	0.00	33,000,000.00	5,360.50	219.18	0.00	5,579.68	6.17146%	8.25000%	7,458.90	219.18	7,678.08	8.49242%	04-Aug-96
05-Aug-96	34,100,000.00	0.00	34,100,000.00	5,329.75	270.55	0.00	5,600.30	5.99445%	8.25000%	7,707.53	270.55	7,978.08	8.53959%	05-Aug-96
06-Aug-96	33,800,000.00	0.00	33,800,000.00	5,108.36	270.55	0.00	5,378.91	5.80858%	8.25000%	7,639.73	270.55	7,910.27	8.54216%	06-Aug-96
07-Aug-96	32,800,000.00	0.00	32,800,000.00	4,889.62	270.55	0.00	5,160.17	5.74226%	8.25000%	7,413.70	270.55	7,684.25	8.55107%	07-Aug-96
08-Aug-96	31,100,000.00	0.00	31,100,000.00	4,678.23	219.18	0.00	4,897.41	5.74776%	8.25000%	7,029.45	219.18	7,248.63	8.50723%	08-Aug-96
09-Aug-96	29,500,000.00	0.00	29,500,000.00	4,418.84	219.18	0.00	4,638.02	5.73856%	8.25000%	6,667.81	219.18	6,886.99	8.52119%	09-Aug-96
10-Aug-96	29,500,000.00	0.00	29,500,000.00	4,418.84	219.18	0.00	4,638.02	5.73856%	8.25000%	6,667.81	219.18	6,886.99	8.52119%	10-Aug-96
11-Aug-96	29,500,000.00	0.00	29,500,000.00	4,418.84	219.18	0.00	4,638.02	5.73856%	8.25000%	6,667.81	219.18	6,886.99	8.52119%	11-Aug-96
12-Aug-96	28,400,000.00	0.00	28,400,000.00	4,290.89	197.26	0.00	4,488.15	5.76822%	8.25000%	6,419.18	197.26	6,616.44	8.50352%	12-Aug-96
13-Aug-96	27,400,000.00	0.00	27,400,000.00	4,160.24	197.26	0.00	4,357.50	5.80470%	8.25000%	6,193.15	197.26	6,390.41	8.51277%	13-Aug-96
14-Aug-96	24,600,000.00	0.00	24,600,000.00	3,755.34	197.26	0.00	3,952.60	5.86463%	8.25000%	5,560.27	197.26	5,757.53	8.54268%	14-Aug-96
15-Aug-96	23,500,000.00	0.00	23,500,000.00	3,531.81	197.26	0.00	3,729.07	5.79196%	8.25000%	5,311.64	197.26	5,508.90	8.55638%	15-Aug-96
16-Aug-96	25,900,000.00	0.00	25,900,000.00	3,917.46	248.63	0.00	4,166.09	5.87113%	8.25000%	5,854.11	248.63	6,102.74	8.60039%	16-Aug-96
17-Aug-96	25,900,000.00	0.00	25,900,000.00	3,917.46	248.63	0.00	4,166.09	5.87113%	8.25000%	5,854.11	248.63	6,102.74	8.60039%	17-Aug-96
18-Aug-96	25,900,000.00	0.00	25,900,000.00	3,917.46	248.63	0.00	4,166.09	5.87113%	8.25000%	5,854.11	248.63	6,102.74	8.60039%	18-Aug-96
19-Aug-96	25,000,000.00	0.00	25,000,000.00	3,810.63	197.26	0.00	4,007.89	5.85152%	8.25000%	5,650.68	197.26	5,847.95	8.53800%	19-Aug-96
20-Aug-96	35,200,000.00	0.00	35,200,000.00	5,265.49	197.26	0.00	5,462.75	5.66450%	8.25000%	7,956.16	197.26	8,153.42	8.45455%	20-Aug-96
21-Aug-96	34,500,000.00	0.00	34,500,000.00	5,086.72	248.63	0.00	5,335.35	5.64465%	8.25000%	7,797.95	248.63	8,046.58	8.51304%	21-Aug-96
22-Aug-96	35,900,000.00	0.00	35,900,000.00	5,330.93	248.63	0.00	5,579.56	5.67281%	8.25000%	8,114.38	248.63	8,363.01	8.50279%	22-Aug-96
23-Aug-96	36,200,000.00	0.00	36,200,000.00	5,353.52	248.63	0.00	5,602.15	5.64858%	8.25000%	8,182.19	248.63	8,430.82	8.50069%	23-Aug-96
24-Aug-96	36,200,000.00	0.00	36,200,000.00	5,353.52	248.63	0.00	5,602.15	5.64858%	8.25000%	8,182.19	248.63	8,430.82	8.50069%	24-Aug-96
25-Aug-96	36,200,000.00	0.00	36,200,000.00	5,353.52	248.63	0.00	5,602.15	5.64858%	8.25000%	8,182.19	248.63	8,430.82	8.50069%	25-Aug-96
26-Aug-96	38,900,000.00	0.00	38,900,000.00	5,905.59	248.63	0.00	6,154.22	5.77453%	8.25000%	8,792.47	248.63	9,041.10	8.48329%	26-Aug-96
27-Aug-96	39,200,000.00	0.00	39,200,000.00	5,900.68	248.63	0.00	6,149.31	5.72576%	8.25000%	8,860.27	248.63	9,108.90	8.48151%	27-Aug-96
28-Aug-96	38,700,000.00	0.00	38,700,000.00	6,011.04	197.26	0.00	6,208.30	5.85537%	8.25000%	8,747.26	197.26	8,944.52	8.43605%	28-Aug-96
29-Aug-96	38,100,000.00	0.00	38,100,000.00	5,794.86	248.63	0.00	6,043.49	5.78970%	8.25000%	8,611.64	248.63	8,860.27	8.48819%	29-Aug-96
30-Aug-96	48,300,000.00	0.00	48,300,000.00	7,434.75	197.26	0.00	7,632.01	5.76746%	8.25000%	10,917.12	197.26	11,114.38	8.39907%	30-Aug-96
31-Aug-96	48,300,000.00	0.00	48,300,000.00	7,434.75	197.26	0.00	7,632.01	5.76746%	8.25000%	10,917.12	197.26	11,114.38	8.39907%	31-Aug-96
				156,019.18	7,075.34	0.00	163,094.52			231,406.85	7,075.34	238,482.19		

48,300,000.00		48,300,000.00	MAXIMUM OUTSTANDING DURING MONTH	
23,500,000.00		23,500,000.00	MINIMUM OUTSTANDING DURING MONTH	
33,025,806.45	0.00	33,025,806.45	MONTH-TO-DATE AVERAGE OUTSTANDING	33,025,806.45
		163,094.52	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	238,482.19
5.8146%	N.A.	5.8146%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5022% (5)
5.5623%		5.5623%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS — FROM: DARLA D. PRUDHOMME — 10

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: SEPTEMBER 30, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Sep-96	48,300,000.00	0.00	48,300,000.00	7,434.75	197.26	0.00	7,632.01	5.76746%	8.25000%	10,917.12	197.26	11,114.38	8.39907%	01-Sep-96
02-Sep-96	48,300,000.00	0.00	48,300,000.00	7,434.75	197.26	0.00	7,632.01	5.76746%	8.25000%	10,917.12	197.26	11,114.38	8.39907%	02-Sep-96
03-Sep-96	49,200,000.00	0.00	49,200,000.00	7,942.04	197.26	0.00	8,139.30	6.03830%	8.25000%	11,120.55	197.26	11,317.81	8.39634%	03-Sep-96
04-Sep-96	49,200,000.00	0.00	49,200,000.00	7,553.45	248.63	0.00	7,802.08	5.78813%	8.25000%	11,120.55	248.63	11,369.18	8.43445%	04-Sep-96
05-Sep-96	48,000,000.00	0.00	48,000,000.00	7,308.32	197.26	0.00	7,505.58	5.70737%	8.25000%	10,849.32	197.26	11,046.58	8.40000%	05-Sep-96
06-Sep-96	47,000,000.00	0.00	47,000,000.00	7,072.17	197.26	0.00	7,269.43	5.64541%	8.25000%	10,623.29	197.26	10,820.55	8.40319%	06-Sep-96
07-Sep-96	47,000,000.00	0.00	47,000,000.00	7,072.17	197.26	0.00	7,269.43	5.64541%	8.25000%	10,623.29	197.26	10,820.55	8.40319%	07-Sep-96
08-Sep-96	47,000,000.00	0.00	47,000,000.00	7,072.17	197.26	0.00	7,269.43	5.64541%	8.25000%	10,623.29	197.26	10,820.55	8.40319%	08-Sep-96
09-Sep-96	48,900,000.00	0.00	48,900,000.00	7,424.98	197.26	0.00	7,622.24	5.68940%	8.25000%	11,052.74	197.26	11,250.00	8.39724%	09-Sep-96
10-Sep-96	47,000,000.00	0.00	47,000,000.00	7,073.29	197.26	0.00	7,270.55	5.64628%	8.25000%	10,623.29	197.26	10,820.55	8.40319%	10-Sep-96
11-Sep-96	45,000,000.00	0.00	45,000,000.00	6,943.63	197.26	0.00	7,140.89	5.79206%	8.25000%	10,171.23	197.26	10,368.49	8.41000%	11-Sep-96
12-Sep-96	42,000,000.00	0.00	42,000,000.00	6,352.64	248.63	0.00	6,601.27	5.73682%	8.25000%	9,493.15	248.63	9,741.78	8.46607%	12-Sep-96
13-Sep-96	40,900,000.00	0.00	40,900,000.00	6,122.44	248.63	0.00	6,371.07	5.68567%	8.25000%	9,244.52	248.63	9,493.15	8.47188%	13-Sep-96
14-Sep-96	40,900,000.00	0.00	40,900,000.00	6,122.44	248.63	0.00	6,371.07	5.68567%	8.25000%	9,244.52	248.63	9,493.15	8.47188%	14-Sep-96
15-Sep-96	40,900,000.00	0.00	40,900,000.00	6,122.44	248.63	0.00	6,371.07	5.68567%	8.25000%	9,244.52	248.63	9,493.15	8.47188%	15-Sep-96
16-Sep-96	45,000,000.00	0.00	45,000,000.00	7,145.49	248.63	0.00	7,394.12	5.99745%	8.25000%	10,171.23	248.63	10,419.86	8.45167%	16-Sep-96
17-Sep-96	45,300,000.00	0.00	45,300,000.00	6,803.71	248.63	0.00	7,052.34	5.68235%	8.25000%	10,239.04	248.63	10,487.67	8.45033%	17-Sep-96
18-Sep-96	45,200,000.00	0.00	45,200,000.00	6,609.98	248.63	0.00	6,858.61	5.53848%	8.25000%	10,216.44	248.63	10,465.07	8.45077%	18-Sep-96
19-Sep-96	44,500,000.00	0.00	44,500,000.00	6,481.37	248.63	0.00	6,730.00	5.52011%	8.25000%	10,058.22	248.63	10,306.85	8.45393%	19-Sep-96
20-Sep-96	44,400,000.00	0.00	44,400,000.00	6,716.18	248.63	0.00	6,964.81	5.72558%	8.25000%	10,035.62	248.63	10,284.25	8.45439%	20-Sep-96
21-Sep-96	44,400,000.00	0.00	44,400,000.00	6,716.18	248.63	0.00	6,964.81	5.72558%	8.25000%	10,035.62	248.63	10,284.25	8.45439%	21-Sep-96
22-Sep-96	44,400,000.00	0.00	44,400,000.00	6,716.18	248.63	0.00	6,964.81	5.72558%	8.25000%	10,035.62	248.63	10,284.25	8.45439%	22-Sep-96
23-Sep-96	36,200,000.00	0.00	36,200,000.00	5,577.92	248.63	0.00	5,826.55	5.87484%	8.25000%	8,182.19	248.63	8,430.82	8.50069%	23-Sep-96
24-Sep-96	39,200,000.00	0.00	39,200,000.00	6,150.03	197.26	0.00	6,347.29	5.91010%	8.25000%	8,860.27	197.26	9,057.53	8.43367%	24-Sep-96
25-Sep-96	41,000,000.00	0.00	41,000,000.00	6,455.78	197.26	0.00	6,653.04	5.92283%	8.25000%	9,267.12	197.26	9,464.38	8.42561%	25-Sep-96
26-Sep-96	41,300,000.00	0.00	41,300,000.00	6,293.16	248.63	0.00	6,541.79	5.78149%	8.25000%	9,334.93	248.63	9,583.56	8.46973%	26-Sep-96
27-Sep-96	41,600,000.00	0.00	41,600,000.00	6,324.99	214.73	0.00	6,539.72	5.73798%	8.25000%	9,402.74	214.73	9,617.47	8.43841%	27-Sep-96
28-Sep-96	41,600,000.00	0.00	41,600,000.00	6,324.99	214.73	0.00	6,539.72	5.73798%	8.25000%	9,402.74	214.73	9,617.47	8.43841%	28-Sep-96
29-Sep-96	41,600,000.00	0.00	41,600,000.00	6,324.99	214.73	0.00	6,539.72	5.73798%	8.25000%	9,402.74	214.73	9,617.47	8.43841%	29-Sep-96
30-Sep-96	52,800,000.00	3,000,000.00	49,800,000.00	8,928.59	197.26	442.19	8,683.66	6.36453%	8.25000%	11,256.16	197.26	11,453.42	8.39458%	30-Sep-96
				204,621.22	6,689.40	442.19	210,868.43			301,769.18	6,689.40	308,458.58		

52,800,000.00		49,800,000.00	MAXIMUM OUTSTANDING DURING MONTH			
36,200,000.00		36,200,000.00	MINIMUM OUTSTANDING DURING MONTH			
44,603,333.33	100,000.00	44,503,333.33	MONTH-TO-DATE AVERAGE OUTSTANDING	44,503,333.33		
		210,868.43	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	308,458.58		
5.7640%	-5.3800%	5.7649%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.4329%	(5)	
5.5816%		5.5820%	ABOVE RATES NET OF COMMITMENT FEES			

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS GMJ
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: OCTOBER 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Oct-96	50,300,000.00	0.00	50,300,000.00	7,920.52	248.63	0.00	8,169.15	5.92791%	8.25000%	11,369.18	248.63	11,617.81	8.43042%	01-Oct-96
02-Oct-96	50,500,000.00	0.00	50,500,000.00	7,726.84	248.63	0.00	7,975.47	5.76445%	8.25000%	11,414.38	248.63	11,663.01	8.42970%	02-Oct-96
03-Oct-96	50,400,000.00	0.00	50,400,000.00	7,560.06	248.63	0.00	7,808.69	5.65510%	8.25000%	11,391.78	248.63	11,640.41	8.43006%	03-Oct-96
04-Oct-96	50,900,000.00	0.00	50,900,000.00	7,609.95	197.26	0.00	7,807.21	5.59849%	8.25000%	11,504.79	197.26	11,702.05	8.39145%	04-Oct-96
05-Oct-96	50,900,000.00	0.00	50,900,000.00	7,609.95	197.26	0.00	7,807.21	5.59849%	8.25000%	11,504.79	197.26	11,702.05	8.39145%	05-Oct-96
06-Oct-96	50,900,000.00	0.00	50,900,000.00	7,609.95	197.26	0.00	7,807.21	5.59849%	8.25000%	11,504.79	197.26	11,702.05	8.39145%	06-Oct-96
07-Oct-96	55,500,000.00	0.00	55,500,000.00	8,327.49	197.26	0.00	8,524.75	5.60637%	8.25000%	12,544.52	197.26	12,741.78	8.37973%	07-Oct-96
08-Oct-96	55,200,000.00	0.00	55,200,000.00	8,250.27	248.63	0.00	8,498.90	5.61974%	8.25000%	12,476.71	248.63	12,725.34	8.41440%	08-Oct-96
09-Oct-96	52,400,000.00	0.00	52,400,000.00	8,268.72	197.26	0.00	8,465.98	5.89710%	8.25000%	11,843.84	197.26	12,041.10	8.38740%	09-Oct-96
10-Oct-96	50,900,000.00	0.00	50,900,000.00	7,707.45	248.63	0.00	7,956.08	5.70524%	8.25000%	11,504.79	248.63	11,753.42	8.42829%	10-Oct-96
11-Oct-96	49,900,000.00	900,000.00	49,000,000.00	7,505.69	248.63	131.67	7,622.65	5.67810%	8.25000%	11,075.34	248.63	11,323.97	8.43520%	11-Oct-96
12-Oct-96	49,900,000.00	900,000.00	49,000,000.00	7,505.69	248.63	131.67	7,622.65	5.67810%	8.25000%	11,075.34	248.63	11,323.97	8.43520%	12-Oct-96
13-Oct-96	49,900,000.00	900,000.00	49,000,000.00	7,505.69	248.63	131.67	7,622.65	5.67810%	8.25000%	11,075.34	248.63	11,323.97	8.43520%	13-Oct-96
14-Oct-96	49,900,000.00	900,000.00	49,000,000.00	7,505.69	248.63	131.67	7,622.65	5.67810%	8.25000%	11,075.34	248.63	11,323.97	8.43520%	14-Oct-96
15-Oct-96	47,600,000.00	0.00	47,600,000.00	7,476.09	248.63	0.00	7,724.72	5.92337%	8.25000%	10,758.90	248.63	11,007.53	8.44065%	15-Oct-96
16-Oct-96	48,500,000.00	0.00	48,500,000.00	7,399.80	197.26	0.00	7,597.06	5.71738%	8.25000%	10,962.33	197.26	11,159.59	8.39845%	16-Oct-96
17-Oct-96	48,500,000.00	0.00	48,500,000.00	7,297.86	197.26	0.00	7,495.12	5.64066%	8.25000%	10,962.33	197.26	11,159.59	8.39845%	17-Oct-96
18-Oct-96	48,800,000.00	0.00	48,800,000.00	7,322.53	197.26	0.00	7,519.79	5.62443%	8.25000%	11,030.14	197.26	11,227.40	8.39754%	18-Oct-96
19-Oct-96	48,800,000.00	0.00	48,800,000.00	7,322.53	197.26	0.00	7,519.79	5.62443%	8.25000%	11,030.14	197.26	11,227.40	8.39754%	19-Oct-96
20-Oct-96	48,800,000.00	0.00	48,800,000.00	7,322.53	197.26	0.00	7,519.79	5.62443%	8.25000%	11,030.14	197.26	11,227.40	8.39754%	20-Oct-96
21-Oct-96	51,400,000.00	0.00	51,400,000.00	7,793.31	197.26	0.00	7,990.57	5.67424%	8.25000%	11,617.81	197.26	11,815.07	8.39008%	21-Oct-96
22-Oct-96	52,700,000.00	0.00	52,700,000.00	7,974.48	197.26	0.00	8,171.74	5.65974%	8.25000%	11,911.64	197.26	12,108.90	8.38662%	22-Oct-96
23-Oct-96	51,500,000.00	0.00	51,500,000.00	8,163.23	197.26	0.00	8,360.49	5.92540%	8.25000%	11,640.41	197.26	11,837.67	8.38981%	23-Oct-96
24-Oct-96	50,900,000.00	0.00	50,900,000.00	7,721.26	248.63	0.00	7,969.89	5.71515%	8.25000%	11,504.79	248.63	11,753.42	8.42829%	24-Oct-96
25-Oct-96	53,600,000.00	0.00	53,600,000.00	8,072.52	248.63	0.00	8,321.15	5.66645%	8.25000%	12,115.07	248.63	12,363.70	8.41931%	25-Oct-96
26-Oct-96	53,600,000.00	0.00	53,600,000.00	8,072.52	248.63	0.00	8,321.15	5.66645%	8.25000%	12,115.07	248.63	12,363.70	8.41931%	26-Oct-96
27-Oct-96	53,600,000.00	0.00	53,600,000.00	8,072.52	248.63	0.00	8,321.15	5.66645%	8.25000%	12,115.07	248.63	12,363.70	8.41931%	27-Oct-96
28-Oct-96	53,100,000.00	0.00	53,100,000.00	8,163.67	248.63	0.00	8,412.30	5.78247%	8.25000%	12,002.05	248.63	12,250.69	8.42090%	28-Oct-96
29-Oct-96	52,600,000.00	0.00	52,600,000.00	7,997.79	248.63	0.00	8,246.42	5.72233%	8.25000%	11,889.04	248.63	12,137.67	8.42253%	29-Oct-96
30-Oct-96	51,700,000.00	0.00	51,700,000.00	7,919.99	197.26	0.00	8,117.25	5.73075%	8.25000%	11,685.62	197.26	11,882.88	8.38926%	30-Oct-96
31-Oct-96	56,600,000.00	0.00	56,600,000.00	9,201.59	197.26	0.00	9,398.85	6.06110%	8.25000%	12,793.15	197.26	12,990.41	8.37721%	31-Oct-96
				241,908.18	6,936.99	526.68	248,318.49			358,524.66	6,936.99	365,461.65		

56,600,000.00		56,600,000.00	MAXIMUM OUTSTANDING DURING MONTH		
47,600,000.00		47,600,000.00	MINIMUM OUTSTANDING DURING MONTH		
51,283,870.97	116,129.03	51,167,741.94	MONTH-TO-DATE AVERAGE OUTSTANDING	51,167,741.94	
		248,318.49	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	365,461.65	
5.7132%	-5.3400%	5.7140%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.4096%	(5)
5.5539%		5.5544%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: NOVEMBER 29, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Nov-96	59,000,000.00	0.00	59,000,000.00	9,558.62	197.26	0.00	9,755.88	6.03542%	8.25000%	13,335.62	197.26	13,532.88	8.37203%	01-Nov-96
02-Nov-96	59,000,000.00	0.00	59,000,000.00	9,558.62	197.26	0.00	9,755.88	6.03542%	8.25000%	13,335.62	197.26	13,532.88	8.37203%	02-Nov-96
03-Nov-96	59,000,000.00	0.00	59,000,000.00	9,558.62	197.26	0.00	9,755.88	6.03542%	8.25000%	13,335.62	197.26	13,532.88	8.37203%	03-Nov-96
04-Nov-96	60,100,000.00	0.00	60,100,000.00	9,336.35	248.63	0.00	9,584.98	5.82116%	8.25000%	13,584.25	248.63	13,832.88	8.40100%	04-Nov-96
05-Nov-96	60,900,000.00	0.00	60,900,000.00	9,162.64	248.63	0.00	9,411.27	5.64058%	8.25000%	13,765.07	248.63	14,013.70	8.39901%	05-Nov-96
06-Nov-96	59,900,000.00	0.00	59,900,000.00	9,677.17	197.26	0.00	9,874.43	6.01697%	8.25000%	13,539.04	197.26	13,736.30	8.37020%	06-Nov-96
07-Nov-96	57,800,000.00	0.00	57,800,000.00	8,841.88	248.63	0.00	9,090.51	5.74055%	8.25000%	13,064.38	248.63	13,313.01	8.40701%	07-Nov-96
08-Nov-96	57,200,000.00	0.00	57,200,000.00	8,588.79	248.63	0.00	8,837.42	5.63926%	8.25000%	12,928.77	248.63	13,177.40	8.40865%	08-Nov-96
09-Nov-96	57,200,000.00	0.00	57,200,000.00	8,588.79	248.63	0.00	8,837.42	5.63926%	8.25000%	12,928.77	248.63	13,177.40	8.40865%	09-Nov-96
10-Nov-96	57,200,000.00	0.00	57,200,000.00	8,588.79	248.63	0.00	8,837.42	5.63926%	8.25000%	12,928.77	248.63	13,177.40	8.40865%	10-Nov-96
11-Nov-96	57,200,000.00	0.00	57,200,000.00	8,588.79	248.63	0.00	8,837.42	5.63926%	8.25000%	12,928.77	248.63	13,177.40	8.40865%	11-Nov-96
12-Nov-96	56,200,000.00	0.00	56,200,000.00	8,686.92	197.26	0.00	8,884.18	5.76997%	8.25000%	12,702.74	197.26	12,900.00	8.37811%	12-Nov-96
13-Nov-96	56,200,000.00	0.00	56,200,000.00	8,623.75	197.26	0.00	8,821.01	5.72895%	8.25000%	12,702.74	197.26	12,900.00	8.37811%	13-Nov-96
14-Nov-96	55,900,000.00	0.00	55,900,000.00	8,529.16	197.26	0.00	8,726.42	5.69793%	8.25000%	12,634.93	197.26	12,832.19	8.37880%	14-Nov-96
15-Nov-96	56,900,000.00	0.00	56,900,000.00	9,382.55	197.26	0.00	9,579.81	6.14522%	8.25000%	12,860.96	197.26	13,058.22	8.37654%	15-Nov-96
16-Nov-96	56,900,000.00	0.00	56,900,000.00	9,382.55	197.26	0.00	9,579.81	6.14522%	8.25000%	12,860.96	197.26	13,058.22	8.37654%	16-Nov-96
17-Nov-96	56,900,000.00	0.00	56,900,000.00	9,382.55	197.26	0.00	9,579.81	6.14522%	8.25000%	12,860.96	197.26	13,058.22	8.37654%	17-Nov-96
18-Nov-96	57,000,000.00	0.00	57,000,000.00	8,808.18	248.63	0.00	9,056.81	5.79954%	8.25000%	12,883.56	248.63	13,132.19	8.40921%	18-Nov-96
19-Nov-96	56,400,000.00	0.00	56,400,000.00	8,452.57	248.63	0.00	8,701.20	5.63110%	8.25000%	12,747.95	248.63	12,996.58	8.41090%	19-Nov-96
20-Nov-96	55,700,000.00	0.00	55,700,000.00	8,822.13	197.26	0.00	9,019.39	5.91037%	8.25000%	12,589.73	197.26	12,786.99	8.37926%	20-Nov-96
21-Nov-96	54,800,000.00	0.00	54,800,000.00	8,343.18	248.63	0.00	8,591.81	5.72265%	8.25000%	12,386.30	248.63	12,634.93	8.41560%	21-Nov-96
22-Nov-96	58,200,000.00	0.00	58,200,000.00	8,726.41	197.26	0.00	8,923.67	5.59646%	8.25000%	13,154.79	197.26	13,352.05	8.37371%	22-Nov-96
23-Nov-96	58,200,000.00	0.00	58,200,000.00	8,726.41	197.26	0.00	8,923.67	5.59646%	8.25000%	13,154.79	197.26	13,352.05	8.37371%	23-Nov-96
24-Nov-96	58,200,000.00	0.00	58,200,000.00	8,726.41	197.26	0.00	8,923.67	5.59646%	8.25000%	13,154.79	197.26	13,352.05	8.37371%	24-Nov-96
25-Nov-96	60,000,000.00	0.00	60,000,000.00	9,204.69	248.63	0.00	9,453.32	5.75077%	8.25000%	13,561.64	248.63	13,810.27	8.40125%	25-Nov-96
26-Nov-96	20,000,000.00	0.00	20,000,000.00	3,025.69	248.63	0.00	3,274.32	5.97563%	8.25000%	4,520.55	248.63	4,769.18	8.70375%	26-Nov-96
27-Nov-96	21,200,000.00	0.00	21,200,000.00	3,278.64	197.26	0.00	3,475.90	5.98445%	8.25000%	4,791.78	197.26	4,989.04	8.58962%	27-Nov-96
28-Nov-96	21,200,000.00	0.00	21,200,000.00	3,278.64	197.26	0.00	3,475.90	5.98445%	8.25000%	4,791.78	197.26	4,989.04	8.58962%	28-Nov-96
29-Nov-96	29,700,000.00	0.00	29,700,000.00	4,904.58	197.26	0.00	5,101.84	6.26994%	8.25000%	6,713.01	197.26	6,910.27	8.49242%	29-Nov-96
30-Nov-96	29,700,000.00	0.00	29,700,000.00	4,904.58	197.26	0.00	5,101.84	6.26994%	8.25000%	6,713.01	197.26	6,910.27	8.49242%	30-Nov-96
				243,238.65	6,534.25	0.00	249,772.90			353,461.64	6,534.25	359,995.89		

60,900,000.00		60,900,000.00	MAXIMUM OUTSTANDING DURING MONTH	
20,000,000.00		20,000,000.00	MINIMUM OUTSTANDING DURING MONTH	
52,126,666.67	0.00	52,126,666.67	MONTH-TO-DATE AVERAGE OUTSTANDING	52,126,666.67
		249,772.90	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	359,995.89
5.8298%	N.A.	5.8298%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.4025% (5)
5.6773%		5.6773%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS 3/17
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: DECEMBER 31, 1996

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Dec-96	29,700,000.00	0.00	29,700,000.00	4,904.58	197.26	0.00	5,101.84	6.26994%	8.25000%	6,713.01	197.26	6,910.27	8.49242%	01-Dec-96
02-Dec-96	29,400,000.00	0.00	29,400,000.00	4,820.09	197.26	0.00	5,017.35	6.22902%	8.25000%	6,645.21	197.26	6,842.47	8.49490%	02-Dec-96
03-Dec-96	27,400,000.00	0.00	27,400,000.00	4,409.78	197.26	0.00	4,607.04	6.13712%	8.25000%	6,193.15	197.26	6,390.41	8.51277%	03-Dec-96
04-Dec-96	24,300,000.00	0.00	24,300,000.00	3,803.04	197.26	0.00	4,000.30	6.00868%	8.25000%	5,492.47	197.26	5,689.73	8.54630%	04-Dec-96
05-Dec-96	21,900,000.00	0.00	21,900,000.00	3,361.81	197.26	0.00	3,559.07	5.93178%	8.25000%	4,950.00	197.26	5,147.26	8.57877%	05-Dec-96
06-Dec-96	19,700,000.00	0.00	19,700,000.00	2,955.10	248.63	0.00	3,203.73	5.93585%	8.25000%	4,452.74	248.63	4,701.37	8.71066%	06-Dec-96
07-Dec-96	19,700,000.00	0.00	19,700,000.00	2,955.10	248.63	0.00	3,203.73	5.93585%	8.25000%	4,452.74	248.63	4,701.37	8.71066%	07-Dec-96
08-Dec-96	19,700,000.00	0.00	19,700,000.00	2,955.10	248.63	0.00	3,203.73	5.93585%	8.25000%	4,452.74	248.63	4,701.37	8.71066%	08-Dec-96
09-Dec-96	22,200,000.00	0.00	22,200,000.00	3,342.85	248.63	0.00	3,591.48	5.90491%	8.25000%	5,017.81	248.63	5,266.44	8.65878%	09-Dec-96
10-Dec-96	20,000,000.00	0.00	20,000,000.00	2,991.67	248.63	0.00	3,240.30	5.91355%	8.25000%	4,520.55	248.63	4,769.18	8.70375%	10-Dec-96
11-Dec-96	18,000,000.00	0.00	18,000,000.00	2,691.67	248.63	0.00	2,940.30	5.96228%	8.25000%	4,068.49	248.63	4,317.12	8.75417%	11-Dec-96
12-Dec-96	16,500,000.00	0.00	16,500,000.00	2,497.83	215.24	0.00	2,713.07	6.00164%	8.25000%	3,729.45	215.24	3,944.69	8.72614%	12-Dec-96
13-Dec-96	14,900,000.00	0.00	14,900,000.00	2,230.93	248.63	0.00	2,479.56	6.07409%	8.25000%	3,367.81	248.63	3,616.44	8.85906%	13-Dec-96
14-Dec-96	14,900,000.00	0.00	14,900,000.00	2,230.93	248.63	0.00	2,479.56	6.07409%	8.25000%	3,367.81	248.63	3,616.44	8.85906%	14-Dec-96
15-Dec-96	14,900,000.00	0.00	14,900,000.00	2,230.93	248.63	0.00	2,479.56	6.07409%	8.25000%	3,367.81	248.63	3,616.44	8.85906%	15-Dec-96
16-Dec-96	15,800,000.00	0.00	15,800,000.00	2,541.22	197.26	0.00	2,738.48	6.32624%	8.25000%	3,571.23	197.26	3,768.49	8.70570%	16-Dec-96
17-Dec-96	16,700,000.00	0.00	16,700,000.00	2,549.53	248.63	0.00	2,798.16	6.11574%	8.25000%	3,774.66	248.63	4,023.29	8.79341%	17-Dec-96
18-Dec-96	15,500,000.00	0.00	15,500,000.00	2,446.54	197.26	0.00	2,643.80	6.22572%	8.25000%	3,503.42	197.26	3,700.68	8.71452%	18-Dec-96
19-Dec-96	12,000,000.00	0.00	12,000,000.00	1,830.21	248.63	0.00	2,078.84	6.32314%	8.25000%	2,712.33	248.63	2,960.96	9.00625%	19-Dec-96
20-Dec-96	13,700,000.00	0.00	13,700,000.00	2,043.13	248.63	0.00	2,291.76	6.10578%	8.25000%	3,096.58	248.63	3,345.21	8.91241%	20-Dec-96
21-Dec-96	13,700,000.00	0.00	13,700,000.00	2,043.13	248.63	0.00	2,291.76	6.10578%	8.25000%	3,096.58	248.63	3,345.21	8.91241%	21-Dec-96
22-Dec-96	13,700,000.00	0.00	13,700,000.00	2,043.13	248.63	0.00	2,291.76	6.10578%	8.25000%	3,096.58	248.63	3,345.21	8.91241%	22-Dec-96
23-Dec-96	15,500,000.00	0.00	15,500,000.00	2,386.70	197.26	0.00	2,583.96	6.08481%	8.25000%	3,503.42	197.26	3,700.68	8.71452%	23-Dec-96
24-Dec-96	17,700,000.00	0.00	17,700,000.00	2,683.11	248.63	0.00	2,931.74	6.04568%	8.25000%	4,000.68	248.63	4,249.32	8.76271%	24-Dec-96
25-Dec-96	17,700,000.00	0.00	17,700,000.00	2,683.11	248.63	0.00	2,931.74	6.04568%	8.25000%	4,000.68	248.63	4,249.32	8.76271%	25-Dec-96
26-Dec-96	23,200,000.00	0.00	23,200,000.00	3,566.49	197.26	0.00	3,763.75	5.92142%	8.25000%	5,243.84	197.26	5,441.10	8.56034%	26-Dec-96
27-Dec-96	21,200,000.00	0.00	21,200,000.00	3,296.85	197.26	0.00	3,494.11	6.01580%	8.25000%	4,791.78	197.26	4,989.04	8.58962%	27-Dec-96
28-Dec-96	21,200,000.00	0.00	21,200,000.00	3,296.85	197.26	0.00	3,494.11	6.01580%	8.25000%	4,791.78	197.26	4,989.04	8.58962%	28-Dec-96
29-Dec-96	21,200,000.00	0.00	21,200,000.00	3,296.85	197.26	0.00	3,494.11	6.01580%	8.25000%	4,791.78	197.26	4,989.04	8.58962%	29-Dec-96
30-Dec-96	26,200,000.00	0.00	26,200,000.00	4,202.80	197.26	0.00	4,400.06	6.12985%	8.25000%	5,921.92	197.26	6,119.18	8.52481%	30-Dec-96
31-Dec-96	42,300,000.00	3,000,000.00	39,300,000.00	7,917.27	197.26	445.48	7,669.05	7.12266%	8.25000%	8,882.88	197.26	9,080.14	8.43321%	31-Dec-96
				97,208.33	6,954.97	445.48	103,717.82			139,571.92	6,954.97	146,526.89		

42,300,000.00		39,300,000.00	MAXIMUM OUTSTANDING DURING MONTH			
12,000,000.00		12,000,000.00	MINIMUM OUTSTANDING DURING MONTH			
20,016,129.03	96,774.19	19,919,354.84	MONTH-TO-DATE AVERAGE OUTSTANDING		19,919,354.84	
		103,717.82	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)		146,526.89	
6.1273%	-5.4200%	6.1307%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)		8.6611%	(5)
		5.7196%	ABOVE RATES NET OF COMMITMENT FEES			

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JANUARY 31, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jan-97	42,300,000.00	3,000,000.00	39,300,000.00	7,917.27	197.26	445.48	7,669.05	7.12266%	8.25000%	8,882.88	197.26	9,080.14	8.43321%	01-Jan-97
02-Jan-97	38,500,000.00	0.00	38,500,000.00	6,324.31	248.63	0.00	6,572.94	6.23149%	8.25000%	8,702.05	248.63	8,950.69	8.48571%	02-Jan-97
03-Jan-97	37,700,000.00	0.00	37,700,000.00	5,782.26	248.63	0.00	6,030.89	5.83893%	8.25000%	8,521.23	248.63	8,769.86	8.49072%	03-Jan-97
04-Jan-97	37,700,000.00	0.00	37,700,000.00	5,782.26	248.63	0.00	6,030.89	5.83893%	8.25000%	8,521.23	248.63	8,769.86	8.49072%	04-Jan-97
05-Jan-97	37,700,000.00	0.00	37,700,000.00	5,782.26	248.63	0.00	6,030.89	5.83893%	8.25000%	8,521.23	248.63	8,769.86	8.49072%	05-Jan-97
06-Jan-97	33,200,000.00	0.00	33,200,000.00	5,028.61	248.63	0.00	5,277.24	5.80179%	8.25000%	7,504.11	248.63	7,752.74	8.52334%	06-Jan-97
07-Jan-97	31,400,000.00	0.00	31,400,000.00	4,692.99	248.63	0.00	4,941.62	5.74424%	8.25000%	7,097.26	248.63	7,345.89	8.53901%	07-Jan-97
08-Jan-97	28,500,000.00	0.00	28,500,000.00	4,322.00	197.26	0.00	4,519.26	5.78782%	8.25000%	6,441.78	197.26	6,639.04	8.50263%	08-Jan-97
09-Jan-97	25,500,000.00	0.00	25,500,000.00	3,869.20	197.26	0.00	4,066.46	5.82062%	8.25000%	5,763.70	197.26	5,960.96	8.53235%	09-Jan-97
10-Jan-97	22,900,000.00	0.00	22,900,000.00	3,426.67	248.63	0.00	3,675.30	5.85801%	8.25000%	5,176.03	248.63	5,424.66	8.64629%	10-Jan-97
11-Jan-97	22,900,000.00	0.00	22,900,000.00	3,426.67	248.63	0.00	3,675.30	5.85801%	8.25000%	5,176.03	248.63	5,424.66	8.64629%	11-Jan-97
12-Jan-97	22,900,000.00	0.00	22,900,000.00	3,426.67	248.63	0.00	3,675.30	5.85801%	8.25000%	5,176.03	248.63	5,424.66	8.64629%	12-Jan-97
13-Jan-97	20,900,000.00	0.00	20,900,000.00	3,177.19	197.26	0.00	3,374.45	5.89318%	8.25000%	4,723.97	197.26	4,921.23	8.59450%	13-Jan-97
14-Jan-97	18,400,000.00	0.00	18,400,000.00	2,751.67	248.63	0.00	3,000.30	5.95168%	8.25000%	4,158.90	248.63	4,407.53	8.74321%	14-Jan-97
15-Jan-97	14,500,000.00	0.00	14,500,000.00	2,266.72	197.26	0.00	2,463.98	6.20243%	8.25000%	3,277.40	197.26	3,474.66	8.74655%	15-Jan-97
16-Jan-97	14,900,000.00	0.00	14,900,000.00	2,251.84	248.63	0.00	2,500.47	6.12531%	8.25000%	3,367.81	248.63	3,616.44	8.85906%	16-Jan-97
17-Jan-97	14,500,000.00	0.00	14,500,000.00	2,136.74	248.63	0.00	2,385.37	6.00455%	8.25000%	3,277.40	248.63	3,526.03	8.87586%	17-Jan-97
18-Jan-97	14,500,000.00	0.00	14,500,000.00	2,136.74	248.63	0.00	2,385.37	6.00455%	8.25000%	3,277.40	248.63	3,526.03	8.87586%	18-Jan-97
19-Jan-97	14,500,000.00	0.00	14,500,000.00	2,136.74	248.63	0.00	2,385.37	6.00455%	8.25000%	3,277.40	248.63	3,526.03	8.87586%	19-Jan-97
20-Jan-97	14,500,000.00	0.00	14,500,000.00	2,136.74	248.63	0.00	2,385.37	6.00455%	8.25000%	3,277.40	248.63	3,526.03	8.87586%	20-Jan-97
21-Jan-97	16,000,000.00	0.00	16,000,000.00	2,423.96	248.63	0.00	2,672.59	6.09685%	8.25000%	3,616.44	248.63	3,865.07	8.81719%	21-Jan-97
22-Jan-97	14,600,000.00	0.00	14,600,000.00	2,202.33	248.63	0.00	2,450.96	6.12740%	8.25000%	3,300.00	248.63	3,548.63	8.87158%	22-Jan-97
23-Jan-97	11,800,000.00	0.00	11,800,000.00	1,770.00	248.63	0.00	2,018.63	6.24407%	8.25000%	2,667.12	248.63	2,915.75	9.01907%	23-Jan-97
24-Jan-97	14,000,000.00	0.00	14,000,000.00	2,087.87	248.63	0.00	2,336.50	6.09159%	8.25000%	3,164.38	248.63	3,413.01	8.89821%	24-Jan-97
25-Jan-97	14,000,000.00	0.00	14,000,000.00	2,087.87	248.63	0.00	2,336.50	6.09159%	8.25000%	3,164.38	248.63	3,413.01	8.89821%	25-Jan-97
26-Jan-97	14,000,000.00	0.00	14,000,000.00	2,087.87	248.63	0.00	2,336.50	6.09159%	8.25000%	3,164.38	248.63	3,413.01	8.89821%	26-Jan-97
27-Jan-97	15,800,000.00	0.00	15,800,000.00	2,416.62	197.26	0.00	2,613.88	6.03839%	8.25000%	3,571.23	197.26	3,768.49	8.70570%	27-Jan-97
28-Jan-97	18,000,000.00	0.00	18,000,000.00	2,745.84	248.63	0.00	2,994.47	6.07212%	8.25000%	4,068.49	248.63	4,317.12	8.75417%	28-Jan-97
29-Jan-97	15,000,000.00	0.00	15,000,000.00	2,372.45	197.26	0.00	2,569.71	6.25296%	8.25000%	3,390.41	197.26	3,587.67	8.73000%	29-Jan-97
30-Jan-97	12,900,000.00	0.00	12,900,000.00	1,994.54	248.63	0.00	2,243.17	6.34695%	8.25000%	2,915.75	248.63	3,164.38	8.95349%	30-Jan-97
31-Jan-97	38,500,000.00	0.00	38,500,000.00	6,154.90	197.26	0.00	6,352.16	6.02218%	8.25000%	8,702.05	197.26	8,899.32	8.43701%	31-Jan-97
				107,119.80	7,296.58	445.48	113,970.90			155,845.89	7,296.58	163,142.47		

42,300,000.00		39,300,000.00	MAXIMUM OUTSTANDING DURING MONTH		
11,800,000.00		11,800,000.00	MINIMUM OUTSTANDING DURING MONTH		
22,338,709.68	96,774.19	22,241,935.48	MONTH-TO-DATE AVERAGE OUTSTANDING	22,241,935.48	
		113,970.90	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	163,142.47	
6.0306%	-5.4200%	6.0333%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.6363%	(5)
5.6460%		5.6470%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

FROM: DARLA D. PRUDHOMME /

WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: FEBRUARY 28, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Feb-97	38,500,000.00	0.00	38,500,000.00	6,154.90	197.26	0.00	6,352.16	6.02218%	8.25000%	8,702.05	197.26	8,899.32	8.43701%	01-Feb-97
02-Feb-97	38,500,000.00	0.00	38,500,000.00	6,154.90	197.26	0.00	6,352.16	6.02218%	8.25000%	8,702.05	197.26	8,899.32	8.43701%	02-Feb-97
03-Feb-97	38,500,000.00	0.00	38,500,000.00	5,905.90	248.63	0.00	6,154.53	5.83481%	8.25000%	8,702.05	248.63	8,950.69	8.48571%	03-Feb-97
04-Feb-97	37,600,000.00	0.00	37,600,000.00	5,663.27	248.63	0.00	5,911.90	5.73895%	8.25000%	8,498.63	248.63	8,747.26	8.49136%	04-Feb-97
05-Feb-97	33,200,000.00	0.00	33,200,000.00	4,938.45	248.63	0.00	5,187.08	5.70266%	8.25000%	7,504.11	248.63	7,752.74	8.52334%	05-Feb-97
06-Feb-97	29,200,000.00	0.00	29,200,000.00	4,388.35	248.63	0.00	4,636.98	5.79623%	8.25000%	6,600.00	248.63	6,848.63	8.56079%	06-Feb-97
07-Feb-97	26,300,000.00	0.00	26,300,000.00	3,900.19	248.63	0.00	4,148.82	5.75787%	8.25000%	5,944.52	248.63	6,193.15	8.59506%	07-Feb-97
08-Feb-97	26,300,000.00	0.00	26,300,000.00	3,900.19	248.63	0.00	4,148.82	5.75787%	8.25000%	5,944.52	248.63	6,193.15	8.59506%	08-Feb-97
09-Feb-97	26,300,000.00	0.00	26,300,000.00	3,900.19	248.63	0.00	4,148.82	5.75787%	8.25000%	5,944.52	248.63	6,193.15	8.59506%	09-Feb-97
10-Feb-97	22,100,000.00	0.00	22,100,000.00	3,357.03	197.26	0.00	3,554.29	5.87021%	8.25000%	4,995.21	197.26	5,192.47	8.57579%	10-Feb-97
11-Feb-97	18,300,000.00	0.00	18,300,000.00	2,730.85	248.63	0.00	2,979.48	5.94268%	8.25000%	4,136.30	248.63	4,384.93	8.74590%	11-Feb-97
12-Feb-97	11,300,000.00	0.00	11,300,000.00	1,739.24	197.26	0.00	1,936.50	6.25507%	8.25000%	2,554.11	197.26	2,751.37	8.88717%	12-Feb-97
13-Feb-97	8,100,000.00	0.00	8,100,000.00	1,215.00	248.63	0.00	1,463.63	6.59537%	8.25000%	1,830.82	248.63	2,079.45	9.37037%	13-Feb-97
14-Feb-97	7,400,000.00	0.00	7,400,000.00	1,090.74	248.63	0.00	1,339.37	6.60635%	8.25000%	1,672.60	248.63	1,921.23	9.47635%	14-Feb-97
15-Feb-97	7,400,000.00	0.00	7,400,000.00	1,090.74	248.63	0.00	1,339.37	6.60635%	8.25000%	1,672.60	248.63	1,921.23	9.47635%	15-Feb-97
16-Feb-97	7,400,000.00	0.00	7,400,000.00	1,090.74	248.63	0.00	1,339.37	6.60635%	8.25000%	1,672.60	248.63	1,921.23	9.47635%	16-Feb-97
17-Feb-97	7,400,000.00	0.00	7,400,000.00	1,090.74	248.63	0.00	1,339.37	6.60635%	8.25000%	1,672.60	248.63	1,921.23	9.47635%	17-Feb-97
18-Feb-97	4,000,000.00	0.00	4,000,000.00	633.42	228.08	0.00	861.50	7.86119%	8.25000%	904.11	228.08	1,132.19	10.33123%	18-Feb-97
19-Feb-97	0.00	0.00	0.00	0.00	248.63	0.00	248.63	N.A.	8.25000%	0.00	248.63	248.63	N/A	19-Feb-97
20-Feb-97	5,200,000.00	0.00	5,200,000.00	775.67	248.63	0.00	1,024.30	7.18980%	8.25000%	1,175.34	248.63	1,423.97	9.99519%	20-Feb-97
21-Feb-97	4,900,000.00	0.00	4,900,000.00	722.75	248.63	0.00	971.38	7.23579%	8.25000%	1,107.53	248.63	1,356.16	10.10204%	21-Feb-97
22-Feb-97	4,900,000.00	0.00	4,900,000.00	722.75	248.63	0.00	971.38	7.23579%	8.25000%	1,107.53	248.63	1,356.16	10.10204%	22-Feb-97
23-Feb-97	4,900,000.00	0.00	4,900,000.00	722.75	248.63	0.00	971.38	7.23579%	8.25000%	1,107.53	248.63	1,356.16	10.10204%	23-Feb-97
24-Feb-97	5,600,000.00	0.00	5,600,000.00	848.44	219.86	0.00	1,068.30	6.96303%	8.25000%	1,265.75	219.86	1,485.61	9.68302%	24-Feb-97
25-Feb-97	16,000,000.00	0.00	16,000,000.00	2,420.44	217.81	0.00	2,638.25	6.01851%	8.25000%	3,616.44	217.81	3,834.25	8.74688%	25-Feb-97
26-Feb-97	13,900,000.00	0.00	13,900,000.00	2,173.21	197.26	0.00	2,370.47	6.22462%	8.25000%	3,141.78	197.26	3,339.04	8.76799%	26-Feb-97
27-Feb-97	11,300,000.00	0.00	11,300,000.00	1,705.59	248.63	0.00	1,954.22	6.31230%	8.25000%	2,554.11	248.63	2,802.74	9.05310%	27-Feb-97
28-Feb-97	20,000,000.00	0.00	20,000,000.00	3,161.11	197.26	0.00	3,358.37	6.12903%	8.25000%	4,520.55	197.26	4,717.81	8.61000%	28-Feb-97
				72,197.55	6,573.29	0.00	78,770.84			107,250.00	6,573.29	113,823.29		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
38,500,000.00		38,500,000.00	MAXIMUM OUTSTANDING DURING MONTH		
0.00		0.00	MINIMUM OUTSTANDING DURING MONTH		
16,946,428.57	0.00	16,946,428.57	MONTH-TO-DATE AVERAGE OUTSTANDING	16,946,428.57	
		78,770.84	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	113,823.29	
6.0593%	N.A.	6.0593%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.7556%	(5)
5.5537%		5.5537%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: MARCH 31, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Mar-97	20,000,000.00	0.00	20,000,000.00	3,161.11	197.26	0.00	3,358.37	6.12903%	8.25000%	4,520.55	197.26	4,717.81	8.61000%	01-Mar-97
02-Mar-97	20,000,000.00	0.00	20,000,000.00	3,161.11	197.26	0.00	3,358.37	6.12903%	8.25000%	4,520.55	197.26	4,717.81	8.61000%	02-Mar-97
03-Mar-97	17,700,000.00	0.00	17,700,000.00	2,750.01	197.26	0.00	2,947.27	6.07770%	8.25000%	4,000.68	197.26	4,197.95	8.65678%	03-Mar-97
04-Mar-97	15,000,000.00	0.00	15,000,000.00	2,263.04	248.63	0.00	2,511.67	6.11173%	8.25000%	3,390.41	248.63	3,639.04	8.85500%	04-Mar-97
05-Mar-97	29,300,000.00	0.00	29,300,000.00	4,359.14	248.63	0.00	4,607.77	5.74006%	8.25000%	6,622.60	248.63	6,871.23	8.55973%	05-Mar-97
06-Mar-97	26,000,000.00	0.00	26,000,000.00	3,923.18	197.26	0.00	4,120.44	5.78446%	8.25000%	5,876.71	197.26	6,073.97	8.52692%	06-Mar-97
07-Mar-97	27,100,000.00	0.00	27,100,000.00	4,036.36	248.63	0.00	4,284.99	5.77130%	8.25000%	6,125.34	248.63	6,373.97	8.58487%	07-Mar-97
08-Mar-97	27,100,000.00	0.00	27,100,000.00	4,036.36	248.63	0.00	4,284.99	5.77130%	8.25000%	6,125.34	248.63	6,373.97	8.58487%	08-Mar-97
09-Mar-97	27,100,000.00	0.00	27,100,000.00	4,036.36	248.63	0.00	4,284.99	5.77130%	8.25000%	6,125.34	248.63	6,373.97	8.58487%	09-Mar-97
10-Mar-97	25,400,000.00	0.00	25,400,000.00	3,855.54	248.63	0.00	4,104.17	5.89773%	8.25000%	5,741.10	248.63	5,989.73	8.60728%	10-Mar-97
11-Mar-97	23,800,000.00	0.00	23,800,000.00	3,639.70	203.42	0.00	3,843.12	5.89386%	8.25000%	5,379.45	203.42	5,582.87	8.56197%	11-Mar-97
12-Mar-97	19,200,000.00	0.00	19,200,000.00	2,935.62	197.26	0.00	3,132.88	5.95574%	8.25000%	4,339.73	197.26	4,536.99	8.62500%	12-Mar-97
13-Mar-97	17,700,000.00	0.00	17,700,000.00	2,657.25	248.63	0.00	2,905.88	5.99235%	8.25000%	4,000.68	248.63	4,249.32	8.76271%	13-Mar-97
14-Mar-97	16,800,000.00	0.00	16,800,000.00	2,483.19	248.63	0.00	2,731.82	5.93520%	8.25000%	3,797.26	248.63	4,045.89	8.79018%	14-Mar-97
15-Mar-97	16,800,000.00	0.00	16,800,000.00	2,483.19	248.63	0.00	2,731.82	5.93520%	8.25000%	3,797.26	248.63	4,045.89	8.79018%	15-Mar-97
16-Mar-97	16,800,000.00	0.00	16,800,000.00	2,483.19	248.63	0.00	2,731.82	5.93520%	8.25000%	3,797.26	248.63	4,045.89	8.79018%	16-Mar-97
17-Mar-97	16,900,000.00	0.00	16,900,000.00	2,602.45	197.26	0.00	2,799.71	6.04671%	8.25000%	3,819.86	197.26	4,017.12	8.67604%	17-Mar-97
18-Mar-97	15,000,000.00	0.00	15,000,000.00	2,301.99	197.26	0.00	2,499.25	6.08151%	8.25000%	3,390.41	197.26	3,587.67	8.73000%	18-Mar-97
19-Mar-97	10,900,000.00	0.00	10,900,000.00	1,644.48	248.63	0.00	1,893.11	6.33931%	8.25000%	2,463.70	248.63	2,712.33	9.08257%	19-Mar-97
20-Mar-97	12,200,000.00	0.00	12,200,000.00	1,887.99	197.26	0.00	2,085.25	6.23866%	8.25000%	2,757.53	197.26	2,954.79	8.84016%	20-Mar-97
21-Mar-97	10,200,000.00	0.00	10,200,000.00	1,539.58	248.63	0.00	1,788.21	6.39899%	8.25000%	2,305.48	248.63	2,554.11	9.13971%	21-Mar-97
22-Mar-97	10,200,000.00	0.00	10,200,000.00	1,539.58	248.63	0.00	1,788.21	6.39899%	8.25000%	2,305.48	248.63	2,554.11	9.13971%	22-Mar-97
23-Mar-97	10,200,000.00	0.00	10,200,000.00	1,539.58	248.63	0.00	1,788.21	6.39899%	8.25000%	2,305.48	248.63	2,554.11	9.13971%	23-Mar-97
24-Mar-97	11,100,000.00	0.00	11,100,000.00	1,736.10	197.26	0.00	1,933.36	6.35745%	8.25000%	2,508.90	197.26	2,706.16	8.89865%	24-Mar-97
25-Mar-97	16,700,000.00	0.00	16,700,000.00	2,698.42	197.26	0.00	2,895.68	6.32888%	8.25000%	3,774.66	197.26	3,971.92	8.68114%	25-Mar-97
26-Mar-97	15,100,000.00	0.00	15,100,000.00	2,491.91	248.63	0.00	2,740.54	6.62448%	8.50000%	3,516.44	248.63	3,765.07	9.10099%	26-Mar-97
27-Mar-97	14,500,000.00	0.00	14,500,000.00	2,324.13	248.63	0.00	2,572.76	6.47626%	8.50000%	3,376.71	248.63	3,625.34	9.12586%	27-Mar-97
28-Mar-97	14,800,000.00	0.00	14,800,000.00	2,426.51	197.26	0.00	2,623.77	6.47078%	8.50000%	3,446.58	197.26	3,643.84	8.98649%	28-Mar-97
29-Mar-97	14,800,000.00	0.00	14,800,000.00	2,426.51	197.26	0.00	2,623.77	6.47078%	8.50000%	3,446.58	197.26	3,643.84	8.98649%	29-Mar-97
30-Mar-97	14,800,000.00	0.00	14,800,000.00	2,426.51	197.26	0.00	2,623.77	6.47078%	8.50000%	3,446.58	197.26	3,643.84	8.98649%	30-Mar-97
31-Mar-97	35,700,000.00	3,000,000.00	32,700,000.00	6,572.90	197.26	467.67	6,302.49	7.03489%	8.50000%	7,615.07	197.26	7,812.33	8.72018%	31-Mar-97
				88,422.99	6,943.15	467.67	94,898.47			128,639.73	6,943.15	135,582.87		

35,700,000.00		32,700,000.00	MAXIMUM OUTSTANDING DURING MONTH		
10,200,000.00		10,200,000.00	MINIMUM OUTSTANDING DURING MONTH		
18,351,612.90	96,774.19	18,254,838.71	MONTH-TO-DATE AVERAGE OUTSTANDING	18,254,838.71	
		94,898.47	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	135,582.87	
6.1186%	-5.6900%	6.1209%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.7450%	(5)
5.6731%		5.6730%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: APRIL 30, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Apr-97	32,700,000.00	0.00	32,700,000.00	5,475.31	248.63	0.00	5,723.94	6.38911%	8.50000%	7,615.07	248.63	7,863.70	8.77752%	01-Apr-97
02-Apr-97	33,500,000.00	0.00	33,500,000.00	5,418.99	248.63	0.00	5,667.62	6.17517%	8.50000%	7,801.37	248.63	8,050.00	8.77090%	02-Apr-97
03-Apr-97	29,900,000.00	0.00	29,900,000.00	4,790.99	248.63	0.00	5,039.62	6.15204%	8.50000%	6,963.01	248.63	7,211.64	8.80351%	03-Apr-97
04-Apr-97	27,500,000.00	0.00	27,500,000.00	4,245.42	248.63	0.00	4,494.05	5.96483%	8.50000%	6,404.11	248.63	6,652.74	8.83000%	04-Apr-97
05-Apr-97	27,500,000.00	0.00	27,500,000.00	4,245.42	248.63	0.00	4,494.05	5.96483%	8.50000%	6,404.11	248.63	6,652.74	8.83000%	05-Apr-97
06-Apr-97	27,500,000.00	0.00	27,500,000.00	4,245.42	248.63	0.00	4,494.05	5.96483%	8.50000%	6,404.11	248.63	6,652.74	8.83000%	06-Apr-97
07-Apr-97	25,100,000.00	0.00	25,100,000.00	3,963.23	205.82	0.00	4,169.05	6.06256%	8.50000%	5,845.21	205.82	6,051.03	8.79930%	07-Apr-97
08-Apr-97	23,500,000.00	0.00	23,500,000.00	3,627.91	248.63	0.00	3,876.54	6.02101%	8.50000%	5,472.60	248.63	5,721.23	8.88617%	08-Apr-97
09-Apr-97	21,000,000.00	0.00	21,000,000.00	3,323.56	197.26	0.00	3,520.82	6.11952%	8.50000%	4,890.41	197.26	5,087.67	8.84286%	09-Apr-97
10-Apr-97	19,300,000.00	0.00	19,300,000.00	3,033.29	197.26	0.00	3,230.55	6.10959%	8.50000%	4,494.52	197.26	4,691.78	8.87306%	10-Apr-97
11-Apr-97	19,000,000.00	0.00	19,000,000.00	2,949.14	248.63	0.00	3,197.77	6.14309%	8.50000%	4,424.66	248.63	4,673.29	8.97763%	11-Apr-97
12-Apr-97	19,000,000.00	0.00	19,000,000.00	2,949.14	248.63	0.00	3,197.77	6.14309%	8.50000%	4,424.66	248.63	4,673.29	8.97763%	12-Apr-97
13-Apr-97	19,000,000.00	0.00	19,000,000.00	2,949.14	248.63	0.00	3,197.77	6.14309%	8.50000%	4,424.66	248.63	4,673.29	8.97763%	13-Apr-97
14-Apr-97	16,300,000.00	0.00	16,300,000.00	2,635.21	197.26	0.00	2,832.47	6.34265%	8.50000%	3,795.89	197.26	3,993.15	8.94172%	14-Apr-97
15-Apr-97	14,900,000.00	0.00	14,900,000.00	2,402.12	197.26	0.00	2,599.38	6.36761%	8.50000%	3,469.86	197.26	3,667.12	8.98322%	15-Apr-97
16-Apr-97	14,500,000.00	0.00	14,500,000.00	2,288.30	248.63	0.00	2,536.93	6.38607%	8.50000%	3,376.71	248.63	3,625.34	9.12586%	16-Apr-97
17-Apr-97	14,300,000.00	0.00	14,300,000.00	2,244.31	248.63	0.00	2,492.94	6.36310%	8.50000%	3,330.14	248.63	3,578.77	9.13462%	17-Apr-97
18-Apr-97	13,700,000.00	0.00	13,700,000.00	2,126.35	248.63	0.00	2,374.98	6.32750%	8.50000%	3,190.41	248.63	3,439.04	9.16241%	18-Apr-97
19-Apr-97	13,700,000.00	0.00	13,700,000.00	2,126.35	248.63	0.00	2,374.98	6.32750%	8.50000%	3,190.41	248.63	3,439.04	9.16241%	19-Apr-97
20-Apr-97	13,700,000.00	0.00	13,700,000.00	2,126.35	248.63	0.00	2,374.98	6.32750%	8.50000%	3,190.41	248.63	3,439.04	9.16241%	20-Apr-97
21-Apr-97	13,600,000.00	0.00	13,600,000.00	2,169.78	197.26	0.00	2,367.04	6.35272%	8.50000%	3,167.12	197.26	3,364.38	9.02941%	21-Apr-97
22-Apr-97	14,400,000.00	0.00	14,400,000.00	2,210.00	248.63	0.00	2,458.63	6.23194%	8.50000%	3,353.42	248.63	3,602.05	9.13021%	22-Apr-97
23-Apr-97	12,900,000.00	0.00	12,900,000.00	2,024.58	248.63	0.00	2,273.21	6.43195%	8.50000%	3,004.11	248.63	3,252.74	9.20349%	23-Apr-97
24-Apr-97	11,900,000.00	0.00	11,900,000.00	1,926.82	197.69	0.00	2,124.51	6.51636%	8.50000%	2,771.23	197.69	2,968.92	9.10636%	24-Apr-97
25-Apr-97	14,500,000.00	0.00	14,500,000.00	2,267.36	248.63	0.00	2,515.99	6.33335%	8.50000%	3,376.71	248.63	3,625.34	9.12586%	25-Apr-97
26-Apr-97	14,500,000.00	0.00	14,500,000.00	2,267.36	248.63	0.00	2,515.99	6.33335%	8.50000%	3,376.71	248.63	3,625.34	9.12586%	26-Apr-97
27-Apr-97	14,500,000.00	0.00	14,500,000.00	2,267.36	248.63	0.00	2,515.99	6.33335%	8.50000%	3,376.71	248.63	3,625.34	9.12586%	27-Apr-97
28-Apr-97	17,000,000.00	0.00	17,000,000.00	2,717.36	248.63	0.00	2,965.99	6.36816%	8.50000%	3,958.90	248.63	4,207.53	9.03382%	28-Apr-97
29-Apr-97	17,500,000.00	0.00	17,500,000.00	2,833.10	197.26	0.00	3,030.36	6.32047%	8.50000%	4,075.34	197.26	4,272.60	8.91143%	29-Apr-97
30-Apr-97	22,400,000.00	0.00	22,400,000.00	3,681.95	197.26	0.00	3,879.21	6.32103%	8.50000%	5,216.44	197.26	5,413.70	8.82143%	30-Apr-97
				91,531.62	7,005.57	0.00	98,537.19			134,789.04	7,005.57	141,794.61		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
33,500,000.00		33,500,000.00	MAXIMUM OUTSTANDING DURING MONTH		
11,900,000.00		11,900,000.00	MINIMUM OUTSTANDING DURING MONTH		
19,293,333.33	0.00	19,293,333.33	MONTH-TO-DATE AVERAGE OUTSTANDING	19,293,333.33	
		98,537.19	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	141,794.61	
6.2139%	N.A.	6.2139%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.9418%	(5)
5.7721%		5.7721%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: MAY 30, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-May-97	23,700,000.00	0.00	23,700,000.00	3,846.20	197.26	0.00	4,043.46	6.22727%	8.50000%	5,519.18	197.26	5,716.44	8.80380%	01-May-97
02-May-97	32,200,000.00	0.00	32,200,000.00	5,129.24	197.26	0.00	5,326.50	6.03780%	8.50000%	7,498.63	197.26	7,695.89	8.72360%	02-May-97
03-May-97	32,200,000.00	0.00	32,200,000.00	5,129.24	197.26	0.00	5,326.50	6.03780%	8.50000%	7,498.63	197.26	7,695.89	8.72360%	03-May-97
04-May-97	32,200,000.00	0.00	32,200,000.00	5,129.24	197.26	0.00	5,326.50	6.03780%	8.50000%	7,498.63	197.26	7,695.89	8.72360%	04-May-97
05-May-97	30,700,000.00	0.00	30,700,000.00	4,850.80	197.26	0.00	5,048.06	6.00177%	8.50000%	7,149.32	197.26	7,346.58	8.73453%	05-May-97
06-May-97	29,500,000.00	0.00	29,500,000.00	4,625.44	248.63	0.00	4,874.07	6.03063%	8.50000%	6,869.86	248.63	7,118.49	8.80763%	06-May-97
07-May-97	26,900,000.00	0.00	26,900,000.00	4,356.21	197.26	0.00	4,553.47	6.17850%	8.50000%	6,264.38	197.26	6,461.64	8.76766%	07-May-97
08-May-97	25,800,000.00	0.00	25,800,000.00	4,116.02	248.63	0.00	4,364.65	6.17480%	8.50000%	6,008.22	248.63	6,256.85	8.85174%	08-May-97
09-May-97	23,800,000.00	0.00	23,800,000.00	3,755.61	248.63	0.00	4,004.24	6.14096%	8.50000%	5,542.47	248.63	5,791.10	8.88130%	09-May-97
10-May-97	23,800,000.00	0.00	23,800,000.00	3,755.61	248.63	0.00	4,004.24	6.14096%	8.50000%	5,542.47	248.63	5,791.10	8.88130%	10-May-97
11-May-97	23,800,000.00	0.00	23,800,000.00	3,755.61	248.63	0.00	4,004.24	6.14096%	8.50000%	5,542.47	248.63	5,791.10	8.88130%	11-May-97
12-May-97	21,600,000.00	0.00	21,600,000.00	3,454.40	197.26	0.00	3,651.66	6.17063%	8.50000%	5,030.14	197.26	5,227.40	8.83333%	12-May-97
13-May-97	18,500,000.00	0.00	18,500,000.00	2,906.39	248.63	0.00	3,155.02	6.22477%	8.50000%	4,308.22	248.63	4,556.85	8.99054%	13-May-97
14-May-97	15,300,000.00	0.00	15,300,000.00	2,392.92	248.63	0.00	2,641.55	6.30174%	8.50000%	3,563.01	248.63	3,811.64	9.09314%	14-May-97
15-May-97	14,200,000.00	0.00	14,200,000.00	2,294.79	197.26	0.00	2,492.05	6.40562%	8.50000%	3,306.85	197.26	3,504.11	9.00704%	15-May-97
16-May-97	15,100,000.00	0.00	15,100,000.00	2,361.53	248.63	0.00	2,610.16	6.30933%	8.50000%	3,516.44	248.63	3,765.07	9.10099%	16-May-97
17-May-97	15,100,000.00	0.00	15,100,000.00	2,361.53	248.63	0.00	2,610.16	6.30933%	8.50000%	3,516.44	248.63	3,765.07	9.10099%	17-May-97
[illegible]-May-97	15,100,000.00	0.00	15,100,000.00	2,361.53	248.63	0.00	2,610.16	6.30933%	8.50000%	3,516.44	248.63	3,765.07	9.10099%	18-May-97
[illegible]-May-97	14,700,000.00	0.00	14,700,000.00	2,370.23	197.26	0.00	2,567.49	6.37506%	8.50000%	3,423.29	197.26	3,620.55	8.98980%	19-May-97
20-May-97	14,700,000.00	0.00	14,700,000.00	2,395.20	197.26	0.00	2,592.46	6.43706%	8.50000%	3,423.29	197.26	3,620.55	8.98980%	20-May-97
21-May-97	13,200,000.00	0.00	13,200,000.00	2,157.36	197.26	0.00	2,354.62	6.51088%	8.50000%	3,073.97	197.26	3,271.23	9.04545%	21-May-97
22-May-97	12,900,000.00	0.00	12,900,000.00	2,035.44	248.63	0.00	2,284.07	6.46268%	8.50000%	3,004.11	248.63	3,252.74	9.20349%	22-May-97
23-May-97	12,700,000.00	0.00	12,700,000.00	1,960.14	248.63	0.00	2,208.77	6.34804%	8.50000%	2,957.53	248.63	3,206.16	9.21457%	23-May-97
24-May-97	12,700,000.00	0.00	12,700,000.00	1,960.14	248.63	0.00	2,208.77	6.34804%	8.50000%	2,957.53	248.63	3,206.16	9.21457%	24-May-97
25-May-97	12,700,000.00	0.00	12,700,000.00	1,960.14	248.63	0.00	2,208.77	6.34804%	8.50000%	2,957.53	248.63	3,206.16	9.21457%	25-May-97
26-May-97	12,700,000.00	0.00	12,700,000.00	1,960.14	248.63	0.00	2,208.77	6.34804%	8.50000%	2,957.53	248.63	3,206.16	9.21457%	26-May-97
27-May-97	18,200,000.00	0.00	18,200,000.00	2,856.44	213.53	0.00	3,069.97	6.15681%	8.50000%	4,238.36	213.53	4,451.89	8.92823%	27-May-97
28-May-97	17,900,000.00	0.00	17,900,000.00	2,867.33	197.26	0.00	3,064.59	6.24902%	8.50000%	4,168.49	197.26	4,365.75	8.90223%	28-May-97
29-May-97	16,300,000.00	0.00	16,300,000.00	2,618.77	197.26	0.00	2,816.03	6.30583%	8.50000%	3,795.89	197.26	3,993.15	8.94172%	29-May-97
30-May-97	29,500,000.00	0.00	29,500,000.00	4,779.50	197.26	0.00	4,976.76	6.15769%	8.50000%	6,869.86	197.26	7,067.12	8.74407%	30-May-97
31-May-97	29,500,000.00	0.00	29,500,000.00	4,779.50	197.26	0.00	4,976.76	6.15769%	8.50000%	6,869.86	197.26	7,067.12	8.74407%	31-May-97
				101,282.64	6,901.89	0.00	108,184.53			148,389.04	6,901.89	155,290.93		

32,200,000.00		32,200,000.00	MAXIMUM OUTSTANDING DURING MONTH	20,554,838.71	
12,700,000.00		12,700,000.00	MINIMUM OUTSTANDING DURING MONTH	155,290.93	
20,554,838.71	0.00	20,554,838.71	MONTH-TO-DATE AVERAGE OUTSTANDING	8.8954%	(5)
		108,184.53	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)		
6.1970%	N.A.	6.1970%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)		
5.8017%		5.8017%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JUNE 30, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O. INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jun-97	29,500,000.00	0.00	29,500,000.00	4,779.50	197.26	0.00	4,976.76	6.15769%	8.50000%	6,869.86	197.26	7,067.12	8.74407%	01-Jun-97
02-Jun-97	30,700,000.00	0.00	30,700,000.00	4,988.34	197.26	0.00	5,185.60	6.16529%	8.50000%	7,149.32	197.26	7,346.58	8.73453%	02-Jun-97
03-Jun-97	30,100,000.00	0.00	30,100,000.00	4,893.36	197.26	0.00	5,090.62	6.17301%	8.50000%	7,009.59	197.26	7,206.85	8.73920%	03-Jun-97
04-Jun-97	28,500,000.00	5,100,000.00	23,400,000.00	4,581.44	197.26	782.47	3,996.23	6.23344%	8.50000%	5,449.32	197.26	5,646.58	8.80769%	04-Jun-97
05-Jun-97	17,100,000.00	0.00	17,100,000.00	2,698.54	248.63	0.00	2,947.17	6.29074%	8.50000%	3,982.19	248.63	4,230.82	9.03070%	05-Jun-97
06-Jun-97	20,100,000.00	0.00	20,100,000.00	3,137.34	248.63	0.00	3,385.97	6.14865%	8.50000%	4,680.82	248.63	4,929.45	8.95149%	06-Jun-97
07-Jun-97	20,100,000.00	0.00	20,100,000.00	3,137.34	248.63	0.00	3,385.97	6.14865%	8.50000%	4,680.82	248.63	4,929.45	8.95149%	07-Jun-97
08-Jun-97	20,100,000.00	0.00	20,100,000.00	3,137.34	248.63	0.00	3,385.97	6.14865%	8.50000%	4,680.82	248.63	4,929.45	8.95149%	08-Jun-97
09-Jun-97	18,500,000.00	0.00	18,500,000.00	2,945.56	197.26	0.00	3,142.82	6.20070%	8.50000%	4,308.22	197.26	4,505.48	8.88919%	09-Jun-97
10-Jun-97	17,600,000.00	0.00	17,600,000.00	2,753.89	248.63	0.00	3,002.52	6.22682%	8.50000%	4,098.63	248.63	4,347.26	9.01563%	10-Jun-97
11-Jun-97	25,200,000.00	0.00	25,200,000.00	4,029.08	197.26	0.00	4,226.34	6.12148%	8.50000%	5,868.49	197.26	6,065.75	8.78571%	11-Jun-97
12-Jun-97	22,800,000.00	0.00	22,800,000.00	3,657.60	197.26	0.00	3,854.86	6.17116%	8.50000%	5,309.59	197.26	5,506.85	8.81579%	12-Jun-97
13-Jun-97	22,800,000.00	0.00	22,800,000.00	3,595.02	248.63	0.00	3,843.65	6.15321%	8.50000%	5,309.59	248.63	5,558.22	8.89803%	13-Jun-97
14-Jun-97	22,800,000.00	0.00	22,800,000.00	3,595.02	248.63	0.00	3,843.65	6.15321%	8.50000%	5,309.59	248.63	5,558.22	8.89803%	14-Jun-97
15-Jun-97	22,800,000.00	0.00	22,800,000.00	3,595.02	248.63	0.00	3,843.65	6.15321%	8.50000%	5,309.59	248.63	5,558.22	8.89803%	15-Jun-97
16-Jun-97	23,400,000.00	0.00	23,400,000.00	3,829.32	197.26	0.00	4,026.58	6.28078%	8.50000%	5,449.32	197.26	5,646.58	8.80769%	16-Jun-97
17-Jun-97	23,400,000.00	0.00	23,400,000.00	3,813.50	197.26	0.00	4,010.76	6.25610%	8.50000%	5,449.32	197.26	5,646.58	8.80769%	17-Jun-97
18-Jun-97	21,700,000.00	0.00	21,700,000.00	3,506.06	197.26	0.00	3,703.32	6.22909%	8.50000%	5,053.42	197.26	5,250.68	8.83180%	18-Jun-97
19-Jun-97	21,100,000.00	0.00	21,100,000.00	3,316.61	248.63	0.00	3,565.24	6.16736%	8.50000%	4,913.70	248.63	5,162.33	8.93010%	19-Jun-97
20-Jun-97	23,900,000.00	0.00	23,900,000.00	3,717.52	248.63	0.00	3,966.15	6.05709%	8.50000%	5,565.75	248.63	5,814.38	8.87971%	20-Jun-97
21-Jun-97	23,900,000.00	0.00	23,900,000.00	3,717.52	248.63	0.00	3,966.15	6.05709%	8.50000%	5,565.75	248.63	5,814.38	8.87971%	21-Jun-97
22-Jun-97	23,900,000.00	0.00	23,900,000.00	3,717.52	248.63	0.00	3,966.15	6.05709%	8.50000%	5,565.75	248.63	5,814.38	8.87971%	22-Jun-97
23-Jun-97	23,000,000.00	0.00	23,000,000.00	3,646.39	197.26	0.00	3,843.65	6.09971%	8.50000%	5,356.16	197.26	5,553.42	8.81304%	23-Jun-97
24-Jun-97	22,700,000.00	0.00	22,700,000.00	3,523.23	248.63	0.00	3,771.86	6.06489%	8.50000%	5,286.30	248.63	5,534.93	8.89978%	24-Jun-97
25-Jun-97	31,200,000.00	0.00	31,200,000.00	4,821.86	248.63	0.00	5,070.49	5.93182%	8.50000%	7,265.75	248.63	7,514.38	8.79087%	25-Jun-97
26-Jun-97	31,100,000.00	0.00	31,100,000.00	4,917.22	197.26	0.00	5,114.48	6.00253%	8.50000%	7,242.47	197.26	7,439.73	8.73151%	26-Jun-97
27-Jun-97	31,200,000.00	0.00	31,200,000.00	4,986.76	197.26	0.00	5,184.02	6.06464%	8.50000%	7,265.75	197.26	7,463.01	8.73077%	27-Jun-97
28-Jun-97	31,200,000.00	0.00	31,200,000.00	4,986.76	197.26	0.00	5,184.02	6.06464%	8.50000%	7,265.75	197.26	7,463.01	8.73077%	28-Jun-97
29-Jun-97	31,200,000.00	0.00	31,200,000.00	4,986.76	197.26	0.00	5,184.02	6.06464%	8.50000%	7,265.75	197.26	7,463.01	8.73077%	29-Jun-97
30-Jun-97	38,700,000.00	2,000,000.00	36,700,000.00	6,734.67	197.26	309.59	6,622.34	6.58625%	8.50000%	8,546.58	197.26	8,743.84	8.69619%	30-Jun-97
				119,746.09	6,636.99	1,092.05	125,291.02			173,073.97	6,636.99	179,710.96		

	38,700,000.00		36,700,000.00	MAXIMUM OUTSTANDING DURING MONTH		
	17,100,000.00		17,100,000.00	MINIMUM OUTSTANDING DURING MONTH	
	25,010,000.00	236,666.67	24,773,333.33	MONTH-TO-DATE AVERAGE OUTSTANDING	24,773,333.33
			125,291.02	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	179,710.96
6.1482%		-5.6141%	6.1533%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.8260% (5)
5.8253%			5.8273%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JULY 31, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jul-97	38,700,000.00	0.00	38,700,000.00	6,529.05	197.26	0.00	6,726.31	6.34394%	8.50000%	9,012.33	197.26	9,209.59	8.68605%	01-Jul-97
02-Jul-97	38,600,000.00	0.00	38,600,000.00	6,577.64	197.26	0.00	6,774.90	6.40632%	8.50000%	8,989.04	197.26	9,186.30	8.68653%	02-Jul-97
03-Jul-97	39,200,000.00	0.00	39,200,000.00	6,193.32	248.63	0.00	6,441.95	5.99824%	8.50000%	9,128.77	248.63	9,377.40	8.73151%	03-Jul-97
04-Jul-97	39,200,000.00	0.00	39,200,000.00	6,193.32	248.63	0.00	6,441.95	5.99824%	8.50000%	9,128.77	248.63	9,377.40	8.73151%	04-Jul-97
05-Jul-97	39,200,000.00	0.00	39,200,000.00	6,193.32	248.63	0.00	6,441.95	5.99824%	8.50000%	9,128.77	248.63	9,377.40	8.73151%	05-Jul-97
06-Jul-97	39,200,000.00	0.00	39,200,000.00	6,193.32	248.63	0.00	6,441.95	5.99824%	8.50000%	9,128.77	248.63	9,377.40	8.73151%	06-Jul-97
07-Jul-97	39,200,000.00	0.00	39,200,000.00	6,226.85	197.26	0.00	6,424.11	5.98163%	8.50000%	9,128.77	197.26	9,326.03	8.68367%	07-Jul-97
08-Jul-97	38,400,000.00	0.00	38,400,000.00	6,134.97	197.26	0.00	6,332.23	6.01892%	8.50000%	8,942.47	197.26	9,139.73	8.68750%	08-Jul-97
09-Jul-97	36,900,000.00	0.00	36,900,000.00	5,789.12	248.63	0.00	6,037.75	5.97230%	8.50000%	8,593.15	248.63	8,841.78	8.74594%	09-Jul-97
10-Jul-97	36,000,000.00	0.00	36,000,000.00	5,693.36	201.54	0.00	5,894.90	5.97677%	8.50000%	8,383.56	201.54	8,585.10	8.70434%	10-Jul-97
11-Jul-97	35,700,000.00	0.00	35,700,000.00	5,548.16	248.63	0.00	5,796.79	5.92669%	8.50000%	8,313.70	248.63	8,562.33	8.75420%	11-Jul-97
12-Jul-97	35,700,000.00	0.00	35,700,000.00	5,548.16	248.63	0.00	5,796.79	5.92669%	8.50000%	8,313.70	248.63	8,562.33	8.75420%	12-Jul-97
13-Jul-97	35,700,000.00	0.00	35,700,000.00	5,548.16	248.63	0.00	5,796.79	5.92669%	8.50000%	8,313.70	248.63	8,562.33	8.75420%	13-Jul-97
14-Jul-97	34,500,000.00	0.00	34,500,000.00	5,437.77	197.26	0.00	5,635.03	5.96170%	8.50000%	8,034.25	197.26	8,231.51	8.70870%	14-Jul-97
15-Jul-97	34,300,000.00	0.00	34,300,000.00	5,527.02	197.26	0.00	5,724.28	6.09144%	8.50000%	7,987.67	197.26	8,184.93	8.70991%	15-Jul-97
16-Jul-97	34,700,000.00	0.00	34,700,000.00	5,595.65	197.26	0.00	5,792.91	6.09341%	8.50000%	8,080.82	197.26	8,278.08	8.70749%	16-Jul-97
17-Jul-97	35,300,000.00	0.00	35,300,000.00	5,594.77	197.26	0.00	5,792.03	5.98893%	8.50000%	8,220.55	197.26	8,417.81	8.70397%	17-Jul-97
18-Jul-97	35,800,000.00	0.00	35,800,000.00	5,580.49	248.63	0.00	5,829.12	5.94310%	8.50000%	8,336.99	248.63	8,585.62	8.75349%	18-Jul-97
19-Jul-97	35,800,000.00	0.00	35,800,000.00	5,580.49	248.63	0.00	5,829.12	5.94310%	8.50000%	8,336.99	248.63	8,585.62	8.75349%	19-Jul-97
20-Jul-97	35,800,000.00	0.00	35,800,000.00	5,580.49	248.63	0.00	5,829.12	5.94310%	8.50000%	8,336.99	248.63	8,585.62	8.75349%	20-Jul-97
21-Jul-97	36,600,000.00	0.00	36,600,000.00	5,752.77	197.26	0.00	5,950.03	5.93377%	8.50000%	8,523.29	197.26	8,720.55	8.69672%	21-Jul-97
22-Jul-97	41,800,000.00	0.00	41,800,000.00	6,581.40	197.26	0.00	6,778.66	5.91917%	8.50000%	9,734.25	197.26	9,931.51	8.67225%	22-Jul-97
23-Jul-97	40,900,000.00	0.00	40,900,000.00	6,472.51	197.26	0.00	6,669.77	5.95224%	8.50000%	9,524.66	197.26	9,721.92	8.67604%	23-Jul-97
24-Jul-97	41,000,000.00	0.00	41,000,000.00	6,538.00	197.26	0.00	6,735.26	5.99602%	8.50000%	9,547.95	197.26	9,745.21	8.67561%	24-Jul-97
25-Jul-97	44,500,000.00	0.00	44,500,000.00	7,050.52	197.26	0.00	7,247.78	5.94481%	8.50000%	10,363.01	197.26	10,560.27	8.66180%	25-Jul-97
26-Jul-97	44,500,000.00	0.00	44,500,000.00	7,050.52	197.26	0.00	7,247.78	5.94481%	8.50000%	10,363.01	197.26	10,560.27	8.66180%	26-Jul-97
27-Jul-97	44,500,000.00	0.00	44,500,000.00	7,050.52	197.26	0.00	7,247.78	5.94481%	8.50000%	10,363.01	197.26	10,560.27	8.66180%	27-Jul-97
28-Jul-97	45,100,000.00	0.00	45,100,000.00	7,230.90	197.26	0.00	7,428.16	6.01170%	8.50000%	10,502.74	197.26	10,700.00	8.65965%	28-Jul-97
29-Jul-97	44,900,000.00	0.00	44,900,000.00	7,233.08	197.26	0.00	7,430.34	6.04025%	8.50000%	10,456.16	197.26	10,653.42	8.66036%	29-Jul-97
30-Jul-97	44,200,000.00	0.00	44,200,000.00	7,310.18	197.26	0.00	7,507.44	6.19958%	8.50000%	10,293.15	197.26	10,490.41	8.66290%	30-Jul-97
31-Jul-97	49,800,000.00	0.00	49,800,000.00	8,375.05	197.26	0.00	8,572.31	6.28292%	8.50000%	11,597.26	197.26	11,794.52	8.64458%	31-Jul-97
				193,910.88	6,684.42	0.00	200,595.30			283,108.22	6,684.42	289,792.64		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NBANK PRIME	
49,800,000.00		49,800,000.00	MAXIMUM OUTSTANDING DURING MONTH		
34,300,000.00		34,300,000.00	MINIMUM OUTSTANDING DURING MONTH		
39,216,129.03	0.00	39,216,129.03	MONTH-TO-DATE AVERAGE OUTSTANDING	39,216,129.03	
		200,595.30	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	289,792.64	
6.0226%	N.A.	6.0226%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.7007%	(5)
5.8220%		5.8220%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS 8/17
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: AUGUST 29, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Aug-97	82,500,000.00	0.00	82,500,000.00	13,623.46	248.63	0.00	13,872.09	6.13735%	8.50000%	19,212.33	248.63	19,460.96	8.61000%	01-Aug-97
02-Aug-97	82,500,000.00	0.00	82,500,000.00	13,623.46	248.63	0.00	13,872.09	6.13735%	8.50000%	19,212.33	248.63	19,460.96	8.61000%	02-Aug-97
03-Aug-97	82,500,000.00	0.00	82,500,000.00	13,623.46	248.63	0.00	13,872.09	6.13735%	8.50000%	19,212.33	248.63	19,460.96	8.61000%	03-Aug-97
04-Aug-97	88,300,000.00	0.00	88,300,000.00	14,165.57	248.63	0.00	14,414.20	5.95830%	8.50000%	20,563.01	248.63	20,811.64	8.60277%	04-Aug-97
05-Aug-97	87,600,000.00	0.00	87,600,000.00	13,947.71	197.26	0.00	14,144.97	5.89374%	8.50000%	20,400.00	197.26	20,597.26	8.58219%	05-Aug-97
06-Aug-97	86,800,000.00	0.00	86,800,000.00	13,761.19	197.26	0.00	13,958.45	5.86962%	8.50000%	20,213.70	197.26	20,410.96	8.58295%	06-Aug-97
07-Aug-97	85,100,000.00	0.00	85,100,000.00	13,561.33	197.26	0.00	13,758.59	5.90116%	8.50000%	19,817.81	197.26	20,015.07	8.58461%	07-Aug-97
08-Aug-97	85,300,000.00	0.00	85,300,000.00	13,438.33	287.67	0.00	13,726.00	5.87338%	8.50000%	19,864.38	287.67	20,152.05	8.62309%	08-Aug-97
09-Aug-97	85,300,000.00	0.00	85,300,000.00	13,438.33	287.67	0.00	13,726.00	5.87338%	8.50000%	19,864.38	287.67	20,152.05	8.62309%	09-Aug-97
10-Aug-97	85,300,000.00	0.00	85,300,000.00	13,438.33	287.67	0.00	13,726.00	5.87338%	8.50000%	19,864.38	287.67	20,152.05	8.62309%	10-Aug-97
11-Aug-97	83,000,000.00	0.00	83,000,000.00	13,314.77	287.67	0.00	13,602.44	5.98180%	8.50000%	19,328.77	287.67	19,616.44	8.62651%	11-Aug-97
12-Aug-97	82,500,000.00	0.00	82,500,000.00	13,213.23	287.67	0.00	13,500.90	5.97313%	8.50000%	19,212.33	287.67	19,500.00	8.62727%	12-Aug-97
13-Aug-97	83,900,000.00	0.00	83,900,000.00	13,719.05	287.67	0.00	14,006.72	6.09351%	8.50000%	19,538.36	287.67	19,826.03	8.62515%	13-Aug-97
14-Aug-97	81,600,000.00	0.00	81,600,000.00	13,172.87	287.67	0.00	13,460.54	6.02095%	8.50000%	19,002.74	287.67	19,290.41	8.62868%	14-Aug-97
15-Aug-97	85,100,000.00	0.00	85,100,000.00	14,012.91	287.67	0.00	14,300.58	6.13362%	8.50000%	19,817.81	287.67	20,105.48	8.62338%	15-Aug-97
16-Aug-97	85,100,000.00	0.00	85,100,000.00	14,012.91	287.67	0.00	14,300.58	6.13362%	8.50000%	19,817.81	287.67	20,105.48	8.62338%	16-Aug-97
17-Aug-97	85,100,000.00	0.00	85,100,000.00	14,012.91	287.67	0.00	14,300.58	6.13362%	8.50000%	19,817.81	287.67	20,105.48	8.62338%	17-Aug-97
18-Aug-97	87,400,000.00	0.00	87,400,000.00	13,949.79	339.04	0.00	14,288.83	5.96730%	8.50000%	20,353.42	339.04	20,692.47	8.64159%	18-Aug-97
19-Aug-97	86,800,000.00	0.00	86,800,000.00	13,705.53	287.67	0.00	13,993.20	5.88424%	8.50000%	20,213.70	287.67	20,501.37	8.62097%	19-Aug-97
20-Aug-97	87,300,000.00	0.00	87,300,000.00	13,762.54	287.67	0.00	14,050.21	5.87437%	8.50000%	20,330.14	287.67	20,617.81	8.62027%	20-Aug-97
21-Aug-97	91,700,000.00	0.00	91,700,000.00	14,551.91	287.67	0.00	14,839.58	5.90670%	8.50000%	21,354.79	287.67	21,642.47	8.61450%	21-Aug-97
22-Aug-97	91,700,000.00	0.00	91,700,000.00	14,444.43	339.04	0.00	14,783.47	5.88437%	8.50000%	21,354.79	339.04	21,693.84	8.63495%	22-Aug-97
23-Aug-97	91,700,000.00	0.00	91,700,000.00	14,444.43	339.04	0.00	14,783.47	5.88437%	8.50000%	21,354.79	339.04	21,693.84	8.63495%	23-Aug-97
24-Aug-97	91,700,000.00	0.00	91,700,000.00	14,444.43	339.04	0.00	14,783.47	5.88437%	8.50000%	21,354.79	339.04	21,693.84	8.63495%	24-Aug-97
25-Aug-97	100,600,000.00	0.00	100,600,000.00	16,270.95	287.67	0.00	16,558.62	6.00785%	8.50000%	23,427.40	287.67	23,715.07	8.60437%	25-Aug-97
26-Aug-97	103,000,000.00	0.00	103,000,000.00	16,650.36	339.04	0.00	16,989.40	6.02052%	8.50000%	23,986.30	339.04	24,325.34	8.62015%	26-Aug-97
27-Aug-97	102,700,000.00	0.00	102,700,000.00	16,896.49	287.67	0.00	17,184.16	6.10732%	8.50000%	23,916.44	287.67	24,204.11	8.60224%	27-Aug-97
28-Aug-97	102,400,000.00	0.00	102,400,000.00	16,593.22	339.04	0.00	16,932.26	6.03543%	8.50000%	23,846.58	339.04	24,185.62	8.62085%	28-Aug-97
29-Aug-97	116,200,000.00	0.00	116,200,000.00	18,913.20	287.67	0.00	19,200.87	6.03125%	8.50000%	27,060.27	287.67	27,347.95	8.59036%	29-Aug-97
30-Aug-97	116,200,000.00	0.00	116,200,000.00	18,913.20	287.67	0.00	19,200.87	6.03125%	8.50000%	27,060.27	287.67	27,347.95	8.59036%	30-Aug-97
31-Aug-97	116,200,000.00	0.00	116,200,000.00	18,913.20	287.67	0.00	19,200.87	6.03125%	8.50000%	27,060.27	287.67	27,347.95	8.59036%	31-Aug-97
				454,533.50	8,798.63	0.00	463,332.13			657,434.25	8,798.63	666,232.88		

116,200,000.00		116,200,000.00	MAXIMUM OUTSTANDING DURING MONTH		
81,600,000.00		81,600,000.00	MINIMUM OUTSTANDING DURING MONTH		
91,067,741.94	0.00	91,067,741.94	MONTH-TO-DATE AVERAGE OUTSTANDING	91,067,741.94	
		463,332.13	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	666,232.88	
5.9904%	N.A.	5.9904%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.6138%	(5)
5.8767%		5.8767%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

FROM: DARLA D. PRUDHOMME

SUBJ: WEIG[illegible]ED AVERAGE COST OF SHORT TERM DEBT
DATE: SE[illegible]BER 30, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET [illegible]TEREST [illegible]PENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Sep-97	116,200,000.00	0.00	116,200,000.00	18,913.20	291.67	0.00	19,204.87	6.03251%	8.50000%	27,060.27	291.67	27,351.94	8.59162%	01-Sep-97
02-Sep-97	118,700,000.00	0.00	118,700,000.00	19,748.77	291.67	0.00	20,040.44	6.16239%	8.50000%	27,642.47	291.67	27,934.13	8.58969%	02-Sep-97
03-Sep-97	118,400,000.00	0.00	118,400,000.00	19,269.12	291.67	0.00	19,560.79	6.03014%	8.50000%	27,572.60	291.67	27,864.27	8.58991%	03-Sep-97
04-Sep-97	116,800,000.00	0.00	116,800,000.00	18,594.99	291.67	0.00	18,886.66	5.90208%	8.50000%	27,200.00	291.67	27,491.67	8.59115%	04-Sep-97
05-Sep-97	115,400,000.00	0.00	115,400,000.00	18,137.81	291.67	0.00	18,429.48	5.82908%	8.50000%	26,873.97	291.67	27,165.64	8.59225%	05-Sep-97
06-Sep-97	115,400,000.00	0.00	115,400,000.00	18,137.81	291.67	0.00	18,429.48	5.82908%	8.50000%	26,873.97	291.67	27,165.64	8.59225%	06-Sep-97
07-Sep-97	115,400,000.00	0.00	115,400,000.00	18,137.81	291.67	0.00	18,429.48	5.82908%	8.50000%	26,873.97	291.67	27,165.64	8.59225%	07-Sep-97
08-Sep-97	115,500,000.00	0.00	115,500,000.00	18,334.88	291.67	0.00	18,626.55	5.88631%	8.50000%	26,897.26	291.67	27,188.93	8.59217%	08-Sep-97
09-Sep-97	120,200,000.00	0.00	120,200,000.00	19,136.85	291.67	0.00	19,428.52	5.89967%	8.50000%	27,991.78	291.67	28,283.45	8.58857%	09-Sep-97
10-Sep-97	118,300,000.00	0.00	118,300,000.00	19,180.47	291.67	0.00	19,472.14	6.00789%	8.50000%	27,549.32	291.67	27,840.98	8.58999%	10-Sep-97
11-Sep-97	115,200,000.00	0.00	115,200,000.00	18,316.23	291.67	0.00	18,607.90	5.89573%	8.50000%	26,827.40	291.67	27,119.06	8.59241%	11-Sep-97
12-Sep-97	115,600,000.00	0.00	115,600,000.00	18,241.65	291.67	0.00	18,533.32	5.85178%	8.50000%	26,920.55	291.67	27,212.21	8.59209%	12-Sep-97
13-Sep-97	115,600,000.00	0.00	115,600,000.00	18,241.65	291.67	0.00	18,533.32	5.85178%	8.50000%	26,920.55	291.67	27,212.21	8.59209%	13-Sep-97
14-Sep-97	115,600,000.00	0.00	115,600,000.00	18,241.65	291.67	0.00	18,533.32	5.85178%	8.50000%	26,920.55	291.67	27,212.21	8.59209%	14-Sep-97
15-Sep-97	114,300,000.00	0.00	114,300,000.00	18,808.03	291.67	0.00	19,099.70	6.09920%	8.50000%	26,617.81	291.67	25,909.47	8.59314%	15-Sep-97
16-Sep-97	115,600,000.00	0.00	115,600,000.00	18,557.35	343.04	0.00	18,900.39	5.96768%	8.50000%	26,920.55	343.04	27,263.58	8.60831%	16-Sep-97
17-Sep-97	114,800,000.00	0.00	114,800,000.00	18,180.70	343.04	0.00	18,523.74	5.88952%	8.50000%	26,734.25	343.04	27,077.28	8.60907%	17-Sep-97
18-Sep-97	113,900,000.00	0.00	113,900,000.00	18,092.10	343.04	0.00	18,435.14	5.90766%	8.50000%	26,524.66	343.04	26,867.69	8.60993%	18-Sep-97
19-Sep-97	114,100,000.00	0.00	114,100,000.00	17,965.23	291.67	0.00	18,256.90	5.84029%	8.50000%	26,571.23	291.67	26,862.90	8.59330%	19-Sep-97
20-Sep-97	114,100,000.00	0.00	114,100,000.00	17,965.23	291.67	0.00	18,256.90	5.84029%	8.50000%	26,571.23	291.67	26,862.90	8.59330%	20-Sep-97
21-Sep-97	114,100,000.00	0.00	114,100,000.00	17,965.23	291.67	0.00	18,256.90	5.84029%	8.50000%	26,571.23	291.67	26,862.90	8.59330%	21-Sep-97
22-Sep-97	122,800,000.00	0.00	122,800,000.00	19,554.73	291.67	0.00	19,846.40	5.89897%	8.50000%	28,597.26	291.67	28,888.93	8.58669%	22-Sep-97
23-Sep-97	124,200,000.00	0.00	124,200,000.00	19,732.96	291.67	0.00	20,024.63	5.88485%	8.50000%	28,923.29	291.67	29,214.95	8.58572%	23-Sep-97
24-Sep-97	122,600,000.00	0.00	122,600,000.00	19,853.65	291.67	0.00	20,145.32	5.99759%	8.50000%	28,550.68	291.67	28,842.35	8.58683%	24-Sep-97
25-Sep-97	129,000,000.00	0.00	129,000,000.00	20,605.89	343.04	0.00	20,948.93	5.92741%	8.50000%	30,041.10	343.04	30,384.13	8.59706%	25-Sep-97
26-Sep-97	132,700,000.00	0.00	132,700,000.00	21,244.10	291.67	0.00	21,535.77	5.92355%	8.50000%	30,902.74	291.67	31,194.41	8.58022%	26-Sep-97
27-Sep-97	132,700,000.00	0.00	132,700,000.00	21,244.10	291.67	0.00	21,535.77	5.92355%	8.50000%	30,902.74	291.67	31,194.41	8.58022%	27-Sep-97
28-Sep-97	132,700,000.00	0.00	132,700,000.00	21,244.10	291.67	0.00	21,535.77	5.92355%	8.50000%	30,902.74	291.67	31,194.41	8.58022%	28-Sep-97
29-Sep-97	133,800,000.00	0.00	133,800,000.00	22,032.49	291.67	0.00	22,324.16	6.08992%	8.50000%	31,158.90	291.67	31,450.57	8.57957%	29-Sep-97
30-Sep-97	160,400,000.00	3,000,000.00	157,400,000.00	26,753.81	58.33	458.63	26,353.51	6.11120%	8.50000%	36,654.79	58.33	36,713.13	8.51353%	30-Sep-97
				580,432.59	8,722.15	458.63	588,696.11			843,269.86	8,722.15	51,992.01		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T.		NET INTEREST EXPENSE	
160,400,000.00		157,400,000.00	MAXIMUM OUTSTANDING DURING MONTH		
113,900,000.00		113,900,000.00	MINIMUM OUTSTANDING DURING MONTH		
120,803,333.33	100,000.00	120,703,333.33	MONTH-TO-DATE AVERAGE OUTSTANDING	12[illegible]03,333.33	
		588,696.11	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	51,992.01	
5.9337%	-5.5800%	5.9339%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5879%	(5)
5.8458%		5.8460%	ABOVE RATES NET OF COMMITMENT FEES		

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(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED [illegible]365 DAYS DIVIDED BY THE NUMBER OF DAYS

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(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY [illegible] DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET [illegible]T POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

DATE	SHORT TERM DEBT OUTSTANDING	SHO..RM INV..MENTS OUT..NDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Oct-97	158,700,000.00	0.00	158,700,000.00	26,268.37	109.70	0.00	26,378.07	6.06679%	8.50000%	36,957.53	109.70	37,067.24	8.52523%	01-Oct-97
02-Oct-97	159,500,000.00	0.00	159,500,000.00	26,369.10	58.33	0.00	26,427.43	6.04766%	8.50000%	37,143.84	58.33	37,202.17	8.51335%	02-Oct-97
03-Oct-97	159,900,000.00	0.00	159,900,000.00	26,342.06	109.70	0.00	26,451.76	6.03808%	8.50000%	37,236.99	109.70	37,346.69	8.52504%	03-Oct-97
04-Oct-97	159,900,000.00	0.00	159,900,000.00	26,342.06	109.70	0.00	26,451.76	6.03808%	8.50000%	37,236.99	109.70	37,346.69	8.52504%	04-Oct-97
05-Oct-97	159,900,000.00	0.00	159,900,000.00	26,342.06	109.70	0.00	26,451.76	6.03808%	8.50000%	37,236.99	109.70	37,346.69	8.52504%	05-Oct-97
06-Oct-97	160,200,000.00	0.00	160,200,000.00	26,463.87	58.33	0.00	26,522.20	6.04282%	8.50000%	37,306.85	58.33	37,365.18	8.51329%	06-Oct-97
07-Oct-97	160,000,000.00	0.00	160,000,000.00	25,410.14	291.67	0.00	25,701.81	5.86322%	8.50000%	37,260.27	291.67	37,551.94	8.56654%	07-Oct-97
08-Oct-97	159,000,000.00	0.00	159,000,000.00	25,604.87	291.67	0.00	25,896.54	5.94480%	8.50000%	37,027.40	291.67	37,319.06	8.56695%	08-Oct-97
09-Oct-97	158,100,000.00	0.00	158,100,000.00	25,186.24	291.67	0.00	25,477.91	5.88200%	8.50000%	36,817.81	291.67	37,109.47	8.56734%	09-Oct-97
10-Oct-97	158,500,000.00	0.00	158,500,000.00	24,893.29	291.67	0.00	25,184.96	5.79969%	8.50000%	36,910.96	291.67	37,202.63	8.56717%	10-Oct-97
11-Oct-97	158,500,000.00	0.00	158,500,000.00	24,893.29	291.67	0.00	25,184.96	5.79969%	8.50000%	36,910.96	291.67	37,202.63	8.56717%	11-Oct-97
12-Oct-97	158,500,000.00	0.00	158,500,000.00	24,893.29	291.67	0.00	25,184.96	5.79969%	8.50000%	36,910.96	291.67	37,202.63	8.56717%	12-Oct-97
13-Oct-97	158,500,000.00	0.00	158,500,000.00	24,893.29	291.67	0.00	25,184.96	5.79969%	8.50000%	36,910.96	291.67	37,202.63	8.56717%	13-Oct-97
14-Oct-97	156,500,000.00	0.00	156,500,000.00	25,033.12	291.67	0.00	25,324.79	5.90642%	8.50000%	36,445.21	291.67	36,736.87	8.56802%	14-Oct-97
15-Oct-97	155,300,000.00	0.00	155,300,000.00	25,362.88	291.67	0.00	25,654.55	6.02956%	8.50000%	36,165.75	291.67	36,457.42	8.56855%	15-Oct-97
16-Oct-97	156,800,000.00	0.00	156,800,000.00	25,162.99	291.67	0.00	25,454.66	5.92535%	8.50000%	36,515.07	291.67	36,806.74	8.56789%	16-Oct-97
17-Oct-97	156,300,000.00	0.00	156,300,000.00	24,746.87	291.67	0.00	25,038.54	5.84713%	8.50000%	36,398.63	291.67	36,690.30	8.56811%	17-Oct-97
18-Oct-97	156,300,000.00	0.00	156,300,000.00	24,746.87	291.67	0.00	25,038.54	5.84713%	8.50000%	36,398.63	291.67	36,690.30	8.56811%	18-Oct-97
19-Oct-97	156,300,000.00	0.00	156,300,000.00	24,746.87	291.67	0.00	25,038.54	5.84713%	8.50000%	36,398.63	291.67	36,690.30	8.56811%	19-Oct-97
20-Oct-97	156,600,000.00	0.00	156,600,000.00	25,313.35	291.67	0.00	25,605.02	5.96796%	8.50000%	36,468.49	291.67	36,760.16	8.56798%	20-Oct-97
21-Oct-97	156,400,000.00	0.00	156,400,000.00	25,194.49	291.67	0.00	25,486.16	5.94786%	8.50000%	36,421.92	291.67	36,713.58	8.56807%	21-Oct-97
22-Oct-97	156,000,000.00	0.00	156,000,000.00	25,669.30	291.67	0.00	25,960.97	6.07420%	8.50000%	36,328.77	291.67	36,620.43	8.56824%	22-Oct-97
23-Oct-97	154,200,000.00	0.00	154,200,000.00	24,946.86	291.67	0.00	25,238.53	5.97410%	8.50000%	35,909.59	291.67	36,201.26	8.56904%	23-Oct-97
24-Oct-97	155,000,000.00	0.00	155,000,000.00	25,045.17	176.37	0.00	25,221.54	5.93927%	8.50000%	36,095.89	176.37	36,272.26	8.54153%	24-Oct-97
25-Oct-97	155,000,000.00	0.00	155,000,000.00	25,045.17	176.37	0.00	25,221.54	5.93927%	8.50000%	36,095.89	176.37	36,272.26	8.54153%	25-Oct-97
26-Oct-97	155,000,000.00	0.00	155,000,000.00	25,045.17	176.37	0.00	25,221.54	5.93927%	8.50000%	36,095.89	176.37	36,272.26	8.54153%	26-Oct-97
27-Oct-97	165,900,000.00	0.00	165,900,000.00	26,892.09	125.00	0.00	27,017.09	5.94409%	8.50000%	38,634.25	125.00	38,759.25	8.52750%	27-Oct-97
28-Oct-97	166,600,000.00	0.00	166,600,000.00	27,092.81	125.00	0.00	27,217.81	5.96309%	8.50000%	38,797.26	125.00	38,922.26	8.52739%	28-Oct-97
29-Oct-97	165,900,000.00	0.00	165,900,000.00	26,898.39	125.00	0.00	27,023.39	5.94547%	8.50000%	38,634.25	125.00	38,759.25	8.52750%	29-Oct-97
30-Oct-97	168,000,000.00	0.00	168,000,000.00	27,307.35	125.00	0.00	27,432.35	5.96000%	8.50000%	39,123.29	125.00	39,248.29	8.52716%	30-Oct-97
31-Oct-97	179,000,000.00	0.00	179,000,000.00	29,333.34	125.00	0.00	29,458.34	6.00687%	8.50000%	41,684.93	125.00	41,809.93	8.52549%	31-Oct-97
				797,485.02	6,667.92	0.00	804,152.94			1,150,480.82	6,667.92	1,157,148.75		

179,000,000.00			179,000,000.00	MAXIMUM OUTSTANDING DURING MONTH		
154,200,000.00			154,200,000.00	MINIMUM OUTSTANDING DURING MONTH		
149,706,060.61		0.00	149,706,060.61	MONTH-TO-DATE AVERAGE OUTSTANDING	149,706,060.61	
			804,152.94	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	1,157,148.75	
	5.9413%	.A.	5.9413%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5493%	(5)
	5.8920%		5.8920%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TE M DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TI ES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF ET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NT INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER O F DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: NOVEMBER 28, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Nov-97	179,000,000.00	0.00	179,000,000.00	29,333.34	125.00	0.00	29,458.34	6.00687%	8.50000%	41,684.93	125.00	41,809.93	8.52549%	01-Nov-97
02-Nov-97	179,000,000.00	0.00	179,000,000.00	29,333.34	125.00	0.00	29,458.34	6.00687%	8.50000%	41,684.93	125.00	41,809.93	8.52549%	02-Nov-97
03-Nov-97	183,900,000.00	0.00	183,900,000.00	30,179.33	125.00	0.00	30,304.33	6.01473%	8.50000%	42,826.03	125.00	42,951.03	8.52481%	03-Nov-97
04-Nov-97	183,700,000.00	0.00	183,700,000.00	29,848.31	176.37	0.00	30,024.68	5.96571%	8.50000%	42,779.45	176.37	42,955.82	8.53504%	04-Nov-97
05-Nov-97	183,500,000.00	0.00	183,500,000.00	30,138.67	125.00	0.00	30,263.67	6.01975%	8.50000%	42,732.88	125.00	42,857.88	8.52486%	05-Nov-97
06-Nov-97	182,100,000.00	0.00	182,100,000.00	29,643.70	176.37	0.00	29,820.07	5.97711%	8.50000%	42,406.85	176.37	42,583.22	8.53535%	06-Nov-97
07-Nov-97	184,000,000.00	0.00	184,000,000.00	29,705.17	176.37	0.00	29,881.54	5.92759%	8.50000%	42,849.32	176.37	43,025.69	8.53499%	07-Nov-97
08-Nov-97	184,000,000.00	0.00	184,000,000.00	29,705.17	176.37	0.00	29,881.54	5.92759%	8.50000%	42,849.32	176.37	43,025.69	8.53499%	08-Nov-97
09-Nov-97	184,000,000.00	0.00	184,000,000.00	29,705.17	176.37	0.00	29,881.54	5.92759%	8.50000%	42,849.32	176.37	43,025.69	8.53499%	09-Nov-97
10-Nov-97	184,200,000.00	0.00	184,200,000.00	29,915.83	125.00	0.00	30,040.83	5.95272%	8.50000%	42,895.89	125.00	43,020.89	8.52477%	10-Nov-97
11-Nov-97	184,200,000.00	0.00	184,200,000.00	29,915.83	125.00	0.00	30,040.83	5.95272%	8.50000%	42,895.89	125.00	43,020.89	8.52477%	11-Nov-97
12-Nov-97	185,200,000.00	0.00	185,200,000.00	30,194.65	125.00	0.00	30,319.65	5.97552%	8.50000%	43,128.77	125.00	43,253.77	8.52464%	12-Nov-97
13-Nov-97	181,900,000.00	0.00	181,900,000.00	29,550.25	125.00	0.00	29,675.25	5.95463%	8.50000%	42,360.27	125.00	42,485.27	8.52508%	13-Nov-97
14-Nov-97	183,000,000.00	0.00	183,000,000.00	29,567.56	125.00	0.00	29,692.56	5.92229%	8.50000%	42,616.44	125.00	42,741.44	8.52493%	14-Nov-97
15-Nov-97	183,000,000.00	0.00	183,000,000.00	29,567.56	125.00	0.00	29,692.56	5.92229%	8.50000%	42,616.44	125.00	42,741.44	8.52493%	15-Nov-97
16-Nov-97	183,000,000.00	0.00	183,000,000.00	29,567.56	125.00	0.00	29,692.56	5.92229%	8.50000%	42,616.44	125.00	42,741.44	8.52493%	16-Nov-97
17-Nov-97	184,300,000.00	0.00	184,300,000.00	30,287.18	125.00	0.00	30,412.18	6.02303%	8.50000%	42,919.18	125.00	43,044.18	8.52476%	17-Nov-97
18-Nov-97	182,600,000.00	0.00	182,600,000.00	29,559.94	176.37	0.00	29,736.31	5.94401%	8.50000%	42,523.29	176.37	42,699.66	8.53525%	18-Nov-97
19-Nov-97	179,100,000.00	0.00	179,100,000.00	29,011.56	125.00	0.00	29,136.56	5.93794%	8.50000%	41,708.22	125.00	41,833.22	8.52547%	19-Nov-97
20-Nov-97	183,300,000.00	0.00	183,300,000.00	29,610.19	125.00	0.00	29,735.19	5.92108%	8.50000%	42,686.30	125.00	42,811.30	8.52489%	20-Nov-97
21-Nov-97	190,400,000.00	0.00	190,400,000.00	30,582.46	125.00	0.00	30,707.46	5.88667%	8.50000%	44,339.73	125.00	44,464.73	8.52396%	21-Nov-97
22-Nov-97	190,400,000.00	0.00	190,400,000.00	30,582.46	125.00	0.00	30,707.46	5.88667%	8.50000%	44,339.73	125.00	44,464.73	8.52396%	22-Nov-97
23-Nov-97	190,400,000.00	0.00	190,400,000.00	30,582.46	125.00	0.00	30,707.46	5.88667%	8.50000%	44,339.73	125.00	44,464.73	8.52396%	23-Nov-97
24-Nov-97	190,100,000.00	0.00	190,100,000.00	30,969.61	83.33	0.00	31,052.94	5.96230%	8.50000%	44,269.86	83.33	44,353.20	8.51600%	24-Nov-97
25-Nov-97	201,500,000.00	0.00	201,500,000.00	32,775.80	83.33	0.00	32,859.13	5.95215%	8.50000%	46,924.66	83.33	47,007.99	8.51510%	25-Nov-97
26-Nov-97	205,400,000.00	0.00	205,400,000.00	33,609.07	83.33	0.00	33,692.40	5.98721%	8.50000%	47,832.88	83.33	47,916.21	8.51481%	26-Nov-97
27-Nov-97	205,400,000.00	0.00	205,400,000.00	33,609.07	83.33	0.00	33,692.40	5.98721%	8.50000%	47,832.88	83.33	47,916.21	8.51481%	27-Nov-97
28-Nov-97	204,200,000.00	0.00	204,200,000.00	33,682.46	83.33	0.00	33,765.79	6.03551%	8.50000%	47,553.42	83.33	47,636.76	8.51490%	28-Nov-97
29-Nov-97	204,200,000.00	0.00	204,200,000.00	33,682.46	83.33	0.00	33,765.79	6.03551%	8.50000%	47,553.42	83.33	47,636.76	8.51490%	29-Nov-97
30-Nov-97	204,200,000.00	0.00	204,200,000.00	33,682.46	83.33	0.00	33,765.79	6.03551%	8.50000%	47,553.42	83.33	47,636.76	8.51490%	30-Nov-97
				918,098.62	3,766.55	0.00	921,865.17			1,314,169.86	3,766.55	1,317,936.42		

205,400,000.00		205,400,000.00	MAXIMUM OUTSTANDING DURING MONTH		
179,000,000.00		179,000,000.00	MINIMUM OUTSTANDING DURING MONTH		
188,106,666.67	0.00	188,106,666.67	MONTH-TO-DATE AVERAGE OUTSTANDING		
		921,865.17	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	188,106,666.67	
5.9626%	N.A.	5.9626%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	1,317,936.42	
5.9382%		5.9382%	ABOVE RATES NET OF COMMITMENT FEES	8.5244%	(5)

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS GMJ
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: DECEMBER 31, 1997

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Dec-97	208,900,000.00	0.00	208,900,000.00	34,495.97	83.33	0.00	34,579.30	6.04186%	8.50000%	48,647.95	83.33	48,731.28	8.51456%	01-Dec-97
02-Dec-97	211,000,000.00	0.00	211,000,000.00	34,497.73	134.70	0.00	34,632.43	5.99092%	8.50000%	49,136.99	134.70	49,271.69	8.52330%	02-Dec-97
03-Dec-97	207,200,000.00	0.00	207,200,000.00	33,861.38	83.33	0.00	33,944.71	5.97964%	8.50000%	48,252.05	83.33	48,335.39	8.51468%	03-Dec-97
04-Dec-97	204,700,000.00	0.00	204,700,000.00	33,360.29	83.33	0.00	33,443.62	5.96332%	8.50000%	47,669.86	83.33	47,753.20	8.51486%	04-Dec-97
05-Dec-97	203,700,000.00	0.00	203,700,000.00	33,030.23	83.33	0.00	33,113.56	5.93346%	8.50000%	47,436.99	83.33	47,520.32	8.51493%	05-Dec-97
06-Dec-97	203,700,000.00	0.00	203,700,000.00	33,030.23	83.33	0.00	33,113.56	5.93346%	8.50000%	47,436.99	83.33	47,520.32	8.51493%	06-Dec-97
07-Dec-97	203,700,000.00	0.00	203,700,000.00	33,030.23	83.33	0.00	33,113.56	5.93346%	8.50000%	47,436.99	83.33	47,520.32	8.51493%	07-Dec-97
08-Dec-97	200,500,000.00	0.00	200,500,000.00	32,563.05	83.33	0.00	32,646.38	5.94311%	8.50000%	46,691.78	83.33	46,775.11	8.51517%	08-Dec-97
09-Dec-97	204,900,000.00	0.00	204,900,000.00	33,159.06	83.33	0.00	33,242.39	5.92166%	8.50000%	47,716.44	83.33	47,799.77	8.51484%	09-Dec-97
10-Dec-97	202,900,000.00	0.00	202,900,000.00	32,876.51	83.33	0.00	32,959.84	5.92920%	8.50000%	47,250.68	83.33	47,334.02	8.51499%	10-Dec-97
11-Dec-97	199,300,000.00	0.00	199,300,000.00	32,271.78	83.33	0.00	32,355.11	5.92555%	8.50000%	46,412.33	83.33	46,495.66	8.51526%	11-Dec-97
12-Dec-97	194,900,000.00	0.00	194,900,000.00	31,695.36	83.33	0.00	31,778.69	5.95137%	8.50000%	45,387.67	83.33	45,471.00	8.51561%	12-Dec-97
13-Dec-97	194,900,000.00	0.00	194,900,000.00	31,695.36	83.33	0.00	31,778.69	5.95137%	8.50000%	45,387.67	83.33	45,471.00	8.51561%	13-Dec-97
14-Dec-97	194,900,000.00	0.00	194,900,000.00	31,695.36	83.33	0.00	31,778.69	5.95137%	8.50000%	45,387.67	83.33	45,471.00	8.51561%	14-Dec-97
15-Dec-97	193,100,000.00	0.00	193,100,000.00	32,008.80	83.33	0.00	32,092.13	6.06609%	8.50000%	44,968.49	83.33	45,051.83	8.51575%	15-Dec-97
16-Dec-97	191,800,000.00	0.00	191,800,000.00	31,367.63	134.70	0.00	31,502.33	5.99497%	8.50000%	44,665.75	134.70	44,800.46	8.52563%	16-Dec-97
17-Dec-97	188,100,000.00	0.00	188,100,000.00	30,910.20	83.33	0.00	30,993.53	6.01416%	8.50000%	43,804.11	83.33	43,887.44	8.51617%	17-Dec-97
18-Dec-97	184,500,000.00	0.00	184,500,000.00	30,331.91	83.33	0.00	30,415.24	6.01711%	8.50000%	42,965.75	83.33	43,049.09	8.51649%	18-Dec-97
19-Dec-97	185,800,000.00	0.00	185,800,000.00	30,259.99	134.70	0.00	30,394.69	5.97097%	8.50000%	43,268.49	134.70	43,403.20	8.52646%	19-Dec-97
20-Dec-97	185,800,000.00	0.00	185,800,000.00	30,259.99	134.70	0.00	30,394.69	5.97097%	8.50000%	43,268.49	134.70	43,403.20	8.52646%	20-Dec-97
21-Dec-97	185,800,000.00	0.00	185,800,000.00	30,259.99	134.70	0.00	30,394.69	5.97097%	8.50000%	43,268.49	134.70	43,403.20	8.52646%	21-Dec-97
22-Dec-97	190,500,000.00	0.00	190,500,000.00	31,067.90	83.33	0.00	31,151.23	5.96861%	8.50000%	44,363.01	83.33	44,446.35	8.51597%	22-Dec-97
23-Dec-97	189,900,000.00	0.00	189,900,000.00	30,990.22	83.33	0.00	31,073.55	5.97254%	8.50000%	44,223.29	83.33	44,306.62	8.51602%	23-Dec-97
24-Dec-97	211,500,000.00	0.00	211,500,000.00	35,787.00	0.00	0.00	35,787.00	6.17601%	8.50000%	49,253.42	0.00	49,253.42	8.50000%	24-Dec-97
25-Dec-97	211,500,000.00	0.00	211,500,000.00	35,787.00	0.00	0.00	35,787.00	6.17601%	8.50000%	49,253.42	0.00	49,253.42	8.50000%	25-Dec-97
26-Dec-97	216,400,000.00	0.00	216,400,000.00	36,495.93	0.00	0.00	36,495.93	6.15574%	8.50000%	50,394.52	0.00	50,394.52	8.50000%	26-Dec-97
27-Dec-97	216,400,000.00	0.00	216,400,000.00	36,495.93	0.00	0.00	36,495.93	6.15574%	8.50000%	50,394.52	0.00	50,394.52	8.50000%	27-Dec-97
28-Dec-97	216,400,000.00	0.00	216,400,000.00	36,495.93	0.00	0.00	36,495.93	6.15574%	8.50000%	50,394.52	0.00	50,394.52	8.50000%	28-Dec-97
29-Dec-97	210,300,000.00	0.00	210,300,000.00	35,581.27	0.00	0.00	35,581.27	6.17554%	8.50000%	48,973.97	0.00	48,973.97	8.50000%	29-Dec-97
30-Dec-97	216,600,000.00	0.00	216,600,000.00	36,751.35	0.00	0.00	36,751.35	6.19309%	8.50000%	50,441.10	0.00	50,441.10	8.50000%	30-Dec-97
31-Dec-97	213,600,000.00	2,000,000.00	211,600,000.00	36,728.99	0.00	312.88	36,416.11	6.28161%	8.50000%	49,276.71	0.00	49,276.71	8.50000%	31-Dec-97
				1,028,842.57	2,173.52	312.88	1,030,703.21			1,453,430.14	2,173.52	1,455,603.65		

216,600,000.00		216,600,000.00	MAXIMUM OUTSTANDING DURING MONTH		
184,500,000.00		184,500,000.00	MINIMUM OUTSTANDING DURING MONTH		
201,393,548.39	64,516.13	201,329,032.26	MONTH-TO-DATE AVERAGE OUTSTANDING	201,329,032.26	
		1,030,703.21	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	1,455,603.65	
6.0277%	-5.7100%	6.0278%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5127%	(5)
6.0150%		6.0151%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS GMJ
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: JANUARY 31, 1998

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Jan-98	213,600,000.00	2,000,000.00	211,600,000.00	36,728.99	0.00	312.88	36,416.11	6.28161%	8.50000%	49,276.71	0.00	49,276.71	8.50000%	01-Jan-98
02-Jan-98	212,200,000.00	0.00	212,200,000.00	36,151.59	0.00	0.00	36,151.59	6.21835%	8.50000%	49,416.44	0.00	49,416.44	8.50000%	02-Jan-98
03-Jan-98	212,200,000.00	0.00	212,200,000.00	36,151.59	0.00	0.00	36,151.59	6.21835%	8.50000%	49,416.44	0.00	49,416.44	8.50000%	03-Jan-98
04-Jan-98	212,200,000.00	0.00	212,200,000.00	36,151.59	0.00	0.00	36,151.59	6.21835%	8.50000%	49,416.44	0.00	49,416.44	8.50000%	04-Jan-98
05-Jan-98	220,500,000.00	0.00	220,500,000.00	37,400.17	51.37	0.00	37,451.54	6.19946%	8.50000%	51,349.32	51.37	51,400.69	8.50850%	05-Jan-98
06-Jan-98	214,900,000.00	0.00	214,900,000.00	36,336.86	51.37	0.00	36,388.23	6.18041%	8.50000%	50,045.21	51.37	50,096.58	8.50873%	06-Jan-98
07-Jan-98	209,400,000.00	0.00	209,400,000.00	35,379.54	0.00	0.00	35,379.54	6.16692%	8.50000%	48,764.38	0.00	48,764.38	8.50000%	07-Jan-98
08-Jan-98	209,300,000.00	0.00	209,300,000.00	35,317.24	0.00	0.00	35,317.24	6.15900%	8.50000%	48,741.10	0.00	48,741.10	8.50000%	08-Jan-98
09-Jan-98	205,400,000.00	0.00	205,400,000.00	34,797.14	0.00	0.00	34,797.14	6.18352%	8.50000%	47,832.88	0.00	47,832.88	8.50000%	09-Jan-98
10-Jan-98	205,400,000.00	0.00	205,400,000.00	34,797.14	0.00	0.00	34,797.14	6.18352%	8.50000%	47,832.88	0.00	47,832.88	8.50000%	10-Jan-98
11-Jan-98	205,400,000.00	0.00	205,400,000.00	34,797.14	0.00	0.00	34,797.14	6.18352%	8.50000%	47,832.88	0.00	47,832.88	8.50000%	11-Jan-98
12-Jan-98	203,000,000.00	0.00	203,000,000.00	34,491.40	0.00	0.00	34,491.40	6.20166%	8.50000%	47,273.97	0.00	47,273.97	8.50000%	12-Jan-98
13-Jan-98	198,300,000.00	0.00	198,300,000.00	33,685.28	0.00	0.00	33,685.28	6.20027%	8.50000%	46,179.45	0.00	46,179.45	8.50000%	13-Jan-98
14-Jan-98	191,500,000.00	0.00	191,500,000.00	32,641.94	0.00	0.00	32,641.94	6.22157%	8.50000%	44,595.89	0.00	44,595.89	8.50000%	14-Jan-98
15-Jan-98	187,800,000.00	0.00	187,800,000.00	32,043.11	0.00	0.00	32,043.11	6.22776%	8.50000%	43,734.25	0.00	43,734.25	8.50000%	15-Jan-98
16-Jan-98	190,400,000.00	0.00	190,400,000.00	32,366.98	51.37	0.00	32,418.35	6.21465%	8.50000%	44,339.73	51.37	44,391.10	8.50985%	16-Jan-98
17-Jan-98	190,400,000.00	0.00	190,400,000.00	32,366.98	51.37	0.00	32,418.35	6.21465%	8.50000%	44,339.73	51.37	44,391.10	8.50985%	17-Jan-98
18-Jan-98	190,400,000.00	0.00	190,400,000.00	32,366.98	51.37	0.00	32,418.35	6.21465%	8.50000%	44,339.73	51.37	44,391.10	8.50985%	18-Jan-98
19-Jan-98	190,400,000.00	0.00	190,400,000.00	32,366.98	51.37	0.00	32,418.35	6.21465%	8.50000%	44,339.73	51.37	44,391.10	8.50985%	19-Jan-98
20-Jan-98	195,500,000.00	0.00	195,500,000.00	33,218.66	0.00	0.00	33,218.66	6.20195%	8.50000%	45,527.40	0.00	45,527.40	8.50000%	20-Jan-98
21-Jan-98	187,200,000.00	0.00	187,200,000.00	31,933.57	0.00	0.00	31,933.57	6.22636%	8.50000%	43,594.52	0.00	43,594.52	8.50000%	21-Jan-98
22-Jan-98	180,400,000.00	0.00	180,400,000.00	30,817.75	51.37	0.00	30,869.12	6.24569%	8.50000%	42,010.96	51.37	42,062.33	8.51039%	22-Jan-98
23-Jan-98	177,500,000.00	0.00	177,500,000.00	30,360.42	51.37	0.00	30,411.79	6.25369%	8.50000%	41,335.62	51.37	41,386.99	8.51056%	23-Jan-98
24-Jan-98	177,500,000.00	0.00	177,500,000.00	30,360.42	51.37	0.00	30,411.79	6.25369%	8.50000%	41,335.62	51.37	41,386.99	8.51056%	24-Jan-98
25-Jan-98	177,500,000.00	0.00	177,500,000.00	30,360.42	51.37	0.00	30,411.79	6.25369%	8.50000%	41,335.62	51.37	41,386.99	8.51056%	25-Jan-98
26-Jan-98	197,200,000.00	0.00	197,200,000.00	31,756.94	0.00	0.00	31,756.94	5.87793%	8.50000%	45,923.29	0.00	45,923.29	8.50000%	26-Jan-98
27-Jan-98	195,700,000.00	0.00	195,700,000.00	31,501.00	0.00	0.00	31,501.00	5.87525%	8.50000%	45,573.97	0.00	45,573.97	8.50000%	27-Jan-98
28-Jan-98	190,000,000.00	0.00	190,000,000.00	30,608.85	0.00	0.00	30,608.85	5.88012%	8.50000%	44,246.58	0.00	44,246.58	8.50000%	28-Jan-98
29-Jan-98	188,400,000.00	0.00	188,400,000.00	30,362.89	0.00	0.00	30,362.89	5.88241%	8.50000%	43,873.97	0.00	43,873.97	8.50000%	29-Jan-98
30-Jan-98	195,600,000.00	0.00	195,600,000.00	31,519.02	0.00	0.00	31,519.02	5.88162%	8.50000%	45,550.68	0.00	45,550.68	8.50000%	30-Jan-98
31-Jan-98	195,600,000.00	0.00	195,600,000.00	31,519.02	0.00	0.00	31,519.02	5.88162%	8.50000%	45,550.68	0.00	45,550.68	8.50000%	31-Jan-98
				1,030,657.60	513.70	312.88	1,030,858.42			1,424,926.03	513.70	1,425,439.73		

220,500,000.00		220,500,000.00	MAXIMUM OUTSTANDING DURING MONTH	
177,500,000.00		177,500,000.00	MINIMUM OUTSTANDING DURING MONTH	
197,445,161.29	64,516.13	197,380,645.16	MONTH-TO-DATE AVERAGE OUTSTANDING	197,380,645.16
		1,030,858.42	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	1,425,439.73
6.1492%	-5.7101%	6.1493%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5031% (5)
6.1461%		6.1462%	ABOVE RATES NET OF COMMITMENT FEES	

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: FEBRUARY 27, 1998

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Feb-98	195,600,000.00	0.00	195,600,000.00	31,519.02	0.00	0.00	31,519.02	5.88162%	8.50000%	45,550.68	0.00	45,550.68	8.50000%	01-Feb-98
02-Feb-98	194,700,000.00	0.00	194,700,000.00	31,697.35	0.00	0.00	31,697.35	5.94224%	8.50000%	45,341.10	0.00	45,341.10	8.50000%	02-Feb-98
03-Feb-98	196,700,000.00	0.00	196,700,000.00	31,949.93	0.00	0.00	31,949.93	5.92869%	8.50000%	45,806.85	0.00	45,806.85	8.50000%	03-Feb-98
04-Feb-98	190,400,000.00	0.00	190,400,000.00	30,918.71	0.00	0.00	30,918.71	5.92717%	8.50000%	44,339.73	0.00	44,339.73	8.50000%	04-Feb-98
05-Feb-98	185,500,000.00	0.00	185,500,000.00	30,115.92	6.42	0.00	30,122.34	5.92704%	8.50000%	43,198.63	6.42	43,205.05	8.50126%	05-Feb-98
06-Feb-98	181,000,000.00	0.00	181,000,000.00	29,396.81	51.37	0.00	29,448.18	5.93845%	8.50000%	42,150.68	51.37	42,202.05	8.51036%	06-Feb-98
07-Feb-98	181,000,000.00	0.00	181,000,000.00	29,396.81	51.37	0.00	29,448.18	5.93845%	8.50000%	42,150.68	51.37	42,202.05	8.51036%	07-Feb-98
08-Feb-98	181,000,000.00	0.00	181,000,000.00	29,396.81	51.37	0.00	29,448.18	5.93845%	8.50000%	42,150.68	51.37	42,202.05	8.51036%	08-Feb-98
09-Feb-98	175,700,000.00	0.00	175,700,000.00	28,167.60	83.33	0.00	28,250.93	5.86886%	8.50000%	40,916.44	83.33	40,999.77	8.51731%	09-Feb-98
10-Feb-98	172,200,000.00	0.00	172,200,000.00	27,613.56	83.33	0.00	27,696.89	5.87071%	8.50000%	40,101.37	83.33	40,184.70	8.51766%	10-Feb-98
11-Feb-98	167,000,000.00	0.00	167,000,000.00	26,861.11	83.33	0.00	26,944.44	5.88905%	8.50000%	38,890.41	83.33	38,973.74	8.51821%	11-Feb-98
12-Feb-98	162,800,000.00	0.00	162,800,000.00	26,078.92	134.70	0.00	26,213.62	5.87713%	8.50000%	37,912.33	134.70	38,047.03	8.53020%	12-Feb-98
13-Feb-98	162,500,000.00	0.00	162,500,000.00	26,013.71	83.33	0.00	26,097.04	5.86180%	8.50000%	37,842.47	83.33	37,925.80	8.51872%	13-Feb-98
14-Feb-98	162,500,000.00	0.00	162,500,000.00	26,013.71	83.33	0.00	26,097.04	5.86180%	8.50000%	37,842.47	83.33	37,925.80	8.51872%	14-Feb-98
15-Feb-98	162,500,000.00	0.00	162,500,000.00	26,013.71	83.33	0.00	26,097.04	5.86180%	8.50000%	37,842.47	83.33	37,925.80	8.51872%	15-Feb-98
16-Feb-98	162,500,000.00	0.00	162,500,000.00	26,013.71	83.33	0.00	26,097.04	5.86180%	8.50000%	37,842.47	83.33	37,925.80	8.51872%	16-Feb-98
17-Feb-98	161,700,000.00	0.00	161,700,000.00	26,454.46	125.00	0.00	26,579.46	5.99969%	8.50000%	37,656.16	125.00	37,781.16	8.52822%	17-Feb-98
18-Feb-98	153,500,000.00	0.00	153,500,000.00	24,786.24	176.37	0.00	24,962.61	5.93573%	8.50000%	35,746.58	176.37	35,922.95	8.54194%	18-Feb-98
19-Feb-98	149,000,000.00	0.00	149,000,000.00	23,885.56	176.37	0.00	24,061.93	5.89437%	8.50000%	34,698.63	176.37	34,875.00	8.54320%	19-Feb-98
20-Feb-98	152,400,000.00	0.00	152,400,000.00	24,378.37	125.00	0.00	24,503.37	5.86859%	8.50000%	35,490.41	125.00	35,615.41	8.52994%	20-Feb-98
21-Feb-98	152,400,000.00	0.00	152,400,000.00	24,378.37	125.00	0.00	24,503.37	5.86859%	8.50000%	35,490.41	125.00	35,615.41	8.52994%	21-Feb-98
22-Feb-98	152,400,000.00	0.00	152,400,000.00	24,378.37	125.00	0.00	24,503.37	5.86859%	8.50000%	35,490.41	125.00	35,615.41	8.52994%	22-Feb-98
23-Feb-98	148,700,000.00	0.00	148,700,000.00	23,932.27	125.00	0.00	24,057.27	5.90511%	8.50000%	34,628.77	125.00	34,753.77	8.53068%	23-Feb-98
24-Feb-98	145,100,000.00	0.00	145,100,000.00	23,559.71	91.46	0.00	23,651.17	5.94947%	8.50000%	33,790.41	91.46	33,881.87	8.52301%	24-Feb-98
25-Feb-98	164,800,000.00	0.00	164,800,000.00	26,865.46	83.33	0.00	26,948.79	5.96863%	8.50000%	38,378.08	83.33	38,461.42	8.51846%	25-Feb-98
26-Feb-98	162,200,000.00	0.00	162,200,000.00	26,430.62	83.33	0.00	26,513.95	5.96646%	8.50000%	37,772.60	83.33	37,855.94	8.51875%	26-Feb-98
27-Feb-98	163,800,000.00	0.00	163,800,000.00	26,673.05	83.33	0.00	26,756.38	5.96220%	8.50000%	38,145.21	83.33	38,228.54	8.51857%	27-Feb-98
28-Feb-98	163,800,000.00	0.00	163,800,000.00	26,673.05	83.33	0.00	26,756.38	5.96220%	8.50000%	38,145.21	83.33	38,228.54	8.51857%	28-Feb-98
				759,562.92	2,281.10	0.00	761,844.02			1,095,312.33	2,281.10	1,097,593.43		

196,700,000.00		196,700,000.00	MAXIMUM OUTSTANDING DURING MONTH		
145,100,000.00		145,100,000.00	MINIMUM OUTSTANDING DURING MONTH		
167,978,571.43	0.00	167,978,571.43	MONTH-TO-DATE AVERAGE OUTSTANDING	167,978,571.43	
		761,844.02	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	1,097,593.43	
5.9122%	N.A.	5.9122%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5177%	(5)
5.8945%		5.8945%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.
(2) SHORT TERM DEBT OUTSTANDING TIMES THE NATIONSBANK PRIME RATE DIVIDED BY 365 DAYS.
(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.
(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.
(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: MARCH 11, 1998

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Mar-98	163,800,000.00	0.00	163,800,000.00	26,673.05	83.33	0.00	26,756.38	5.96220%	8.50000%	38,145.21	83.33	38,228.54	8.51857%	01-Mar-98
02-Mar-98	163,400,000.00	0.00	163,400,000.00	26,710.30	83.33	0.00	26,793.63	5.98511%	8.50000%	38,052.05	83.33	38,135.39	8.51861%	02-Mar-98
03-Mar-98	160,600,000.00	0.00	160,600,000.00	26,331.90	100.00	0.00	26,431.90	6.00725%	8.50000%	37,400.00	100.00	37,500.00	8.52273%	03-Mar-98
04-Mar-98	157,500,000.00	0.00	157,500,000.00	25,534.63	100.00	0.00	25,634.63	5.94072%	8.50000%	36,678.08	100.00	36,778.08	8.52317%	04-Mar-98
05-Mar-98	152,600,000.00	0.00	152,600,000.00	24,735.11	100.00	0.00	24,835.11	5.94025%	8.50000%	35,536.99	100.00	35,636.99	8.52392%	05-Mar-98
06-Mar-98	148,000,000.00	0.00	148,000,000.00	23,967.14	100.00	0.00	24,067.14	5.93548%	8.50000%	34,465.75	100.00	34,565.75	8.52466%	06-Mar-98
07-Mar-98	148,000,000.00	0.00	148,000,000.00	23,967.14	100.00	0.00	24,067.14	5.93548%	8.50000%	34,465.75	100.00	34,565.75	8.52466%	07-Mar-98
08-Mar-98	148,000,000.00	0.00	148,000,000.00	23,967.14	100.00	0.00	24,067.14	5.93548%	8.50000%	34,465.75	100.00	34,565.75	8.52466%	08-Mar-98
09-Mar-98	151,900,000.00	0.00	151,900,000.00	24,646.12	100.00	0.00	24,746.12	5.94624%	8.50000%	35,373.97	100.00	35,473.97	8.52403%	09-Mar-98
10-Mar-98	149,200,000.00	0.00	149,200,000.00	24,042.41	125.00	0.00	24,167.41	5.91227%	8.50000%	34,745.21	125.00	34,870.21	8.53058%	10-Mar-98
11-Mar-98	144,400,000.00	0.00	144,400,000.00	23,415.56	125.00	0.00	23,540.56	5.95035%	8.50000%	33,627.40	125.00	33,752.40	8.53160%	11-Mar-98
12-Mar-98	137,400,000.00	0.00	137,400,000.00	22,255.83	125.00	0.00	22,380.83	5.94542%	8.50000%	31,997.26	125.00	32,122.26	8.53321%	12-Mar-98
13-Mar-98	137,400,000.00	0.00	137,400,000.00	22,224.60	125.00	0.00	22,349.60	5.93712%	8.50000%	31,997.26	125.00	32,122.26	8.53321%	13-Mar-98
14-Mar-98	137,400,000.00	0.00	137,400,000.00	22,224.60	125.00	0.00	22,349.60	5.93712%	8.50000%	31,997.26	125.00	32,122.26	8.53321%	14-Mar-98
15-Mar-98	137,400,000.00	0.00	137,400,000.00	22,224.60	125.00	0.00	22,349.60	5.93712%	8.50000%	31,997.26	125.00	32,122.26	8.53321%	15-Mar-98
16-Mar-98	141,200,000.00	0.00	141,200,000.00	23,037.11	125.00	0.00	23,162.11	5.98737%	8.50000%	32,882.19	125.00	33,007.19	8.53231%	16-Mar-98
17-Mar-98	137,800,000.00	0.00	137,800,000.00	22,299.16	141.67	0.00	22,440.83	5.94405%	8.50000%	32,090.41	141.67	32,232.08	8.53752%	17-Mar-98
18-Mar-98	132,100,000.00	0.00	132,100,000.00	21,314.09	141.67	0.00	21,455.76	5.92835%	8.50000%	30,763.01	141.67	30,904.68	8.53914%	18-Mar-98
19-Mar-98	126,900,000.00	0.00	126,900,000.00	20,386.22	193.04	0.00	20,579.26	5.91917%	8.50000%	29,552.05	193.04	29,745.09	8.55552%	19-Mar-98
20-Mar-98	131,000,000.00	0.00	131,000,000.00	21,047.03	145.95	0.00	21,192.98	5.90491%	8.50000%	30,506.85	145.95	30,652.80	8.54066%	20-Mar-98
21-Mar-98	131,000,000.00	0.00	131,000,000.00	21,047.03	145.95	0.00	21,192.98	5.90491%	8.50000%	30,506.85	145.95	30,652.80	8.54066%	21-Mar-98
22-Mar-98	131,000,000.00	0.00	131,000,000.00	21,047.03	145.95	0.00	21,192.98	5.90491%	8.50000%	30,506.85	145.95	30,652.80	8.54066%	22-Mar-98
23-Mar-98	128,900,000.00	0.00	128,900,000.00	20,754.41	141.67	0.00	20,896.08	5.91704%	8.50000%	30,017.81	141.67	30,159.47	8.54012%	23-Mar-98
24-Mar-98	125,400,000.00	0.00	125,400,000.00	20,093.16	158.33	0.00	20,251.49	5.89457%	8.50000%	29,202.74	158.33	29,361.07	8.54609%	24-Mar-98
25-Mar-98	134,700,000.00	0.00	134,700,000.00	21,817.36	158.33	0.00	21,975.69	5.95481%	8.50000%	31,368.49	158.33	31,526.83	8.54290%	25-Mar-98
26-Mar-98	134,600,000.00	0.00	134,600,000.00	21,785.61	209.70	0.00	21,995.31	5.96455%	8.50000%	31,345.21	209.70	31,554.91	8.55687%	26-Mar-98
27-Mar-98	135,200,000.00	0.00	135,200,000.00	21,731.54	187.01	0.00	21,918.55	5.91736%	8.50000%	31,484.93	187.01	31,671.94	8.55049%	27-Mar-98
28-Mar-98	135,200,000.00	0.00	135,200,000.00	21,731.54	187.01	0.00	21,918.55	5.91736%	8.50000%	31,484.93	187.01	31,671.94	8.55049%	28-Mar-98
29-Mar-98	135,200,000.00	0.00	135,200,000.00	21,731.54	187.01	0.00	21,918.55	5.91736%	8.50000%	31,484.93	187.01	31,671.94	8.55049%	29-Mar-98
30-Mar-98	136,700,000.00	0.00	136,700,000.00	22,269.88	158.33	0.00	22,428.21	5.98851%	8.50000%	31,834.25	158.33	31,992.58	8.54228%	30-Mar-98
31-Mar-98	141,700,000.00	2,000,000.00	139,700,000.00	23,634.49	108.33	300.27	23,442.55	6.12493%	8.50000%	32,532.88	108.33	32,641.21	8.52830%	31-Mar-98
				708,647.33	4,151.62	300.27	712,498.68			1,018,509.59	4,151.62	1,022,661.21		

SHORT TERM DEBT	SHORT TERM INVESTMENTS	NET S. T. DEBT/(INVEST)		NET INTEREST EXPENSE	
163,800,000.00		163,800,000.00	MAXIMUM OUTSTANDING DURING MONTH		
125,400,000.00		125,400,000.00	MINIMUM OUTSTANDING DURING MONTH		
141,148,387.10	64,516.13	141,083,870.97	MONTH-TO-DATE AVERAGE OUTSTANDING	141,083,870.97	
		712,498.68	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	1,022,661.21	
5.9460%	-5.4799%	5.9462%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5346%	(5)
5.9113%		5.9115%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: APRIL 30, 1998

DATE	SHORT TERM DEBT OUTSTANDING	SHORT TERM INVESTMENTS OUTSTANDING	NET S. T. DEBT/(INVEST) OUTSTANDING	INTEREST EXPENSE	COMMITMENT FEES	INTEREST INCOME	NET EXPENSE/ (INCOME)	EFF. RATE OF S.T. DEBT/(-) R.O.INVEST(1)	NATIONSBANK PRIME RATE	INTEREST EXPENSE (2)	COMMITMENT FEES	NET INTEREST EXPENSE	COMPARATIVE EFF. RATE OF S/T DEBT @ NBANK PRIME	DATE
01-Apr-98	134,600,000.00	0.00	134,600,000.00	22,289.69	132.99	0.00	22,422.68	6.08045%	8.50000%	31,345.21	132.99	31,478.20	8.53606%	01-Apr-98
02-Apr-98	131,600,000.00	0.00	131,600,000.00	21,669.38	132.99	0.00	21,802.37	6.04701%	8.50000%	30,646.58	132.99	30,779.57	8.53689%	02-Apr-98
03-Apr-98	129,900,000.00	0.00	129,900,000.00	21,354.94	132.99	0.00	21,487.93	6.03779%	8.50000%	30,250.68	132.99	30,383.68	8.53737%	03-Apr-98
04-Apr-98	129,900,000.00	0.00	129,900,000.00	21,354.94	132.99	0.00	21,487.93	6.03779%	8.50000%	30,250.68	132.99	30,383.68	8.53737%	04-Apr-98
05-Apr-98	129,900,000.00	0.00	129,900,000.00	21,354.94	132.99	0.00	21,487.93	6.03779%	8.50000%	30,250.68	132.99	30,383.68	8.53737%	05-Apr-98
06-Apr-98	130,900,000.00	0.00	130,900,000.00	21,561.21	108.33	0.00	21,669.54	6.04231%	8.50000%	30,483.56	108.33	30,591.89	8.53021%	06-Apr-98
07-Apr-98	127,300,000.00	0.00	127,300,000.00	20,593.80	166.67	0.00	20,760.47	5.95253%	8.50000%	29,645.21	166.67	29,811.87	8.54779%	07-Apr-98
08-Apr-98	122,900,000.00	0.00	122,900,000.00	19,957.51	166.67	0.00	20,124.18	5.97667%	8.50000%	28,620.55	166.67	28,787.21	8.54950%	08-Apr-98
09-Apr-98	119,100,000.00	0.00	119,100,000.00	19,332.59	191.33	0.00	19,523.92	5.98340%	8.50000%	27,735.62	191.33	27,926.94	8.55863%	09-Apr-98
10-Apr-98	119,000,000.00	0.00	119,000,000.00	19,178.34	191.33	0.00	19,369.67	5.94112%	8.50000%	27,712.33	191.33	27,903.66	8.55868%	10-Apr-98
11-Apr-98	119,000,000.00	0.00	119,000,000.00	19,178.34	191.33	0.00	19,369.67	5.94112%	8.50000%	27,712.33	191.33	27,903.66	8.55868%	11-Apr-98
12-Apr-98	119,000,000.00	0.00	119,000,000.00	19,178.34	191.33	0.00	19,369.67	5.94112%	8.50000%	27,712.33	191.33	27,903.66	8.55868%	12-Apr-98
13-Apr-98	121,800,000.00	0.00	121,800,000.00	19,758.91	166.67	0.00	19,925.58	5.97113%	8.50000%	28,364.38	166.67	28,531.05	8.54995%	13-Apr-98
14-Apr-98	120,200,000.00	0.00	120,200,000.00	19,499.99	191.67	0.00	19,691.66	5.97958%	8.50000%	27,991.78	191.67	28,183.45	8.55820%	14-Apr-98
15-Apr-98	115,800,000.00	0.00	115,800,000.00	18,984.06	191.67	0.00	19,175.73	6.04416%	8.50000%	26,967.12	191.67	27,158.79	8.56041%	15-Apr-98
16-Apr-98	112,700,000.00	0.00	112,700,000.00	18,163.20	216.33	0.00	18,379.53	5.95255%	8.50000%	26,245.21	216.33	26,461.53	8.57006%	16-Apr-98
17-Apr-98	109,300,000.00	0.00	109,300,000.00	17,551.05	216.33	0.00	17,767.38	5.93330%	8.50000%	25,453.42	216.33	25,669.75	8.57224%	17-Apr-98
18-Apr-98	109,300,000.00	0.00	109,300,000.00	17,551.05	216.33	0.00	17,767.38	5.93330%	8.50000%	25,453.42	216.33	25,669.75	8.57224%	18-Apr-98
19-Apr-98	109,300,000.00	0.00	109,300,000.00	17,551.05	216.33	0.00	17,767.38	5.93330%	8.50000%	25,453.42	216.33	25,669.75	8.57224%	19-Apr-98
20-Apr-98	107,100,000.00	0.00	107,100,000.00	17,300.33	216.33	0.00	17,516.66	5.96973%	8.50000%	24,941.10	216.33	25,157.42	8.57372%	20-Apr-98
21-Apr-98	109,100,000.00	0.00	109,100,000.00	17,402.43	232.99	0.00	17,635.42	5.90003%	8.50000%	25,406.85	232.99	25,639.84	8.57795%	21-Apr-98
22-Apr-98	104,500,000.00	0.00	104,500,000.00	16,838.40	208.33	0.00	17,046.73	5.95412%	8.50000%	24,335.62	208.33	24,543.95	8.57277%	22-Apr-98
23-Apr-98	102,100,000.00	0.00	102,100,000.00	16,323.23	232.99	0.00	16,556.22	5.91873%	8.50000%	23,776.71	232.99	24,009.71	8.58329%	23-Apr-98
24-Apr-98	118,500,000.00	0.00	118,500,000.00	18,866.99	225.59	0.00	19,092.58	5.88084%	8.50000%	27,595.89	225.59	27,821.48	8.56949%	24-Apr-98
25-Apr-98	118,500,000.00	0.00	118,500,000.00	18,866.99	225.59	0.00	19,092.58	5.88084%	8.50000%	27,595.89	225.59	27,821.48	8.56949%	25-Apr-98
26-Apr-98	118,500,000.00	0.00	118,500,000.00	18,866.99	225.59	0.00	19,092.58	5.88084%	8.50000%	27,595.89	225.59	27,821.48	8.56949%	26-Apr-98
27-Apr-98	123,100,000.00	0.00	123,100,000.00	19,831.12	208.33	0.00	20,039.45	5.94184%	8.50000%	28,667.12	208.33	28,875.46	8.56177%	27-Apr-98
28-Apr-98	119,800,000.00	0.00	119,800,000.00	19,212.13	222.92	0.00	19,435.05	5.92136%	8.50000%	27,898.63	222.92	28,121.55	8.56792%	28-Apr-98
29-Apr-98	119,000,000.00	0.00	119,000,000.00	19,092.30	208.33	0.00	19,300.63	5.91994%	8.50000%	27,712.33	208.33	27,920.66	8.56390%	29-Apr-98
30-Apr-98	130,000,000.00	0.00	130,000,000.00	20,972.14	208.33	0.00	21,180.47	5.94683%	8.50000%	30,273.97	208.33	30,482.31	8.55849%	30-Apr-98
				579,636.38	5,702.60	0.00	585,338.98			834,094.52	5,702.60	839,797.12		

134,600,000.00		134,600,000.00	MAXIMUM OUTSTANDING DURING MONTH		
102,100,000.00		102,100,000.00	MINIMUM OUTSTANDING DURING MONTH		
119,390,000.00	0.00	119,390,000.00	MONTH-TO-DATE AVERAGE OUTSTANDING	119,390,000.00	
		585,338.98	NET MONTH-TO-DATE INTEREST EXPENSE/(INCOME)	839,797.12	
5.9650%	N.A.	5.9650%	MONTH-TO-DATE AVERAGE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENT (3) & (4)	8.5581%	(5)
5.9069%		5.9069%	ABOVE RATES NET OF COMMITMENT FEES		

(1) THE EFFECTIVE RATE OF SHORT TERM DEBT/(-)RETURN ON INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST EXPENSE/(INCOME) BY NET SHORT TERM DEBT/(INVESTMENTS) OUTSTANDING MULTIPLIED BY 365 DAYS.

(3) THE AVERAGE EFFECTIVE RATE OF NET SHORT TERM DEBT IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE AVERAGE NET SHORT TERM DEBT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED IN THE MONTH.

(4) THE AVERAGE EFFECTIVE RATE ON NET INVESTMENTS IS COMPUTED BY DIVIDING THE NET INTEREST (INCOME) BY THE AVERAGE NET SHORT TERM INVESTMENT OUTSTANDING MULTIPLIED BY 365 DAYS DIVIDED BY THE NUMBER OF DAYS ELAPSED WITHIN THE MONTH.

(5) THE AVERAGE EFFECTIVE RATE OF BORROWING ON A DAILY BASIS AT NATIONSBANK PRIME RATE IS COMPUTED BY DIVIDING THE TOTAL NET INTEREST EXPENSE BY THE DAILY AVERAGE NET DEBT POSITION MULTIPLIED BY 365 DIVIDED BY THE ACTUAL NUMBER OF DAYS ELAPSED IN THE MONTH; IF THERE IS NET INCOME, THIS COMPUTATION IS NOT APPLICABLE.

TO GARY M JENKINS
FROM DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 29-May-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-May-98	127,200,000.00	0.00	127,200,000.00	20,347.46	232.99	0.00	20,580.45	5.90555%	8.50000%	29,621.92	232.99	29,854.91	8.56686%	01-May-98
02-May-98	127,200,000.00	0.00	127,200,000.00	20,347.46	232.99	0.00	20,580.45	5.90555%	8.50000%	29,621.92	232.99	29,854.91	8.56686%	02-May-98
03-May-98	127,200,000.00	0.00	127,200,000.00	20,347.46	232.99	0.00	20,580.45	5.90555%	8.50000%	29,621.92	232.99	29,854.91	8.56686%	03-May-98
04-May-98	124,800,000.00	0.00	124,800,000.00	20,062.55	212.65	0.00	20,275.20	5.92985%	8.50000%	29,063.01	212.65	29,275.67	8.56219%	04-May-98
05-May-98	122,600,000.00	0.00	122,600,000.00	19,539.58	208.33	0.00	19,747.91	5.87927%	8.50000%	28,550.68	208.33	28,759.02	8.56202%	05-May-98
06-May-98	124,200,000.00	0.00	124,200,000.00	19,791.83	208.33	0.00	20,000.16	5.87766%	8.50000%	28,923.29	208.33	29,131.62	8.56123%	06-May-98
07-May-98	123,400,000.00	0.00	123,400,000.00	19,514.62	208.33	0.00	19,722.95	5.83377%	8.50000%	28,736.99	208.33	28,945.32	8.56162%	07-May-98
08-May-98	127,400,000.00	0.00	127,400,000.00	20,167.36	208.33	0.00	20,375.69	5.83762%	8.50000%	29,668.49	208.33	29,876.83	8.55969%	08-May-98
09-May-98	127,400,000.00	0.00	127,400,000.00	20,167.36	208.33	0.00	20,375.69	5.83762%	8.50000%	29,668.49	208.33	29,876.83	8.55969%	09-May-98
10-May-98	127,400,000.00	0.00	127,400,000.00	20,167.36	208.33	0.00	20,375.69	5.83762%	8.50000%	29,668.49	208.33	29,876.83	8.55969%	10-May-98
11-May-98	127,400,000.00	0.00	127,400,000.00	20,441.33	208.33	0.00	20,649.66	5.91611%	8.50000%	29,668.49	208.33	29,876.83	8.55969%	11-May-98
12-May-98	124,200,000.00	0.00	124,200,000.00	20,008.91	208.33	0.00	20,217.24	5.94146%	8.50000%	28,923.29	208.33	29,131.62	8.56123%	12-May-98
13-May-98	121,100,000.00	0.00	121,100,000.00	19,526.45	208.33	0.00	19,734.78	5.94814%	8.50000%	28,201.37	208.33	28,409.70	8.56279%	13-May-98
14-May-98	117,500,000.00	0.00	117,500,000.00	18,938.73	208.33	0.00	19,147.06	5.94781%	8.50000%	27,363.01	208.33	27,571.35	8.56472%	14-May-98
15-May-98	116,400,000.00	0.00	116,400,000.00	19,102.06	208.33	0.00	19,310.39	6.05524%	8.50000%	27,106.85	208.33	27,315.18	8.56533%	15-May-98
16-May-98	116,400,000.00	0.00	116,400,000.00	19,102.06	208.33	0.00	19,310.39	6.05524%	8.50000%	27,106.85	208.33	27,315.18	8.56533%	16-May-98
17-May-98	116,400,000.00	0.00	116,400,000.00	19,102.06	208.33	0.00	19,310.39	6.05524%	8.50000%	27,106.85	208.33	27,315.18	8.56533%	17-May-98
18-May-98	114,500,000.00	0.00	114,500,000.00	18,576.68	208.33	0.00	18,785.01	5.98824%	8.50000%	26,664.38	208.33	26,872.72	8.56641%	18-May-98
19-May-98	112,000,000.00	0.00	112,000,000.00	17,972.95	232.99	0.00	18,205.94	5.93319%	8.50000%	26,082.19	232.99	26,315.19	8.57593%	19-May-98
20-May-98	111,700,000.00	0.00	111,700,000.00	17,915.10	208.33	0.00	18,123.43	5.92216%	8.50000%	26,012.33	208.33	26,220.66	8.56808%	20-May-98
21-May-98	112,600,000.00	0.00	112,600,000.00	18,015.94	232.99	0.00	18,248.93	5.91551%	8.50000%	26,221.92	232.99	26,454.91	8.57553%	21-May-98
22-May-98	114,100,000.00	0.00	114,100,000.00	18,188.35	232.99	0.00	18,421.34	5.89289%	8.50000%	26,571.23	232.99	26,804.23	8.57453%	22-May-98
23-May-98	114,100,000.00	0.00	114,100,000.00	18,188.35	232.99	0.00	18,421.34	5.89289%	8.50000%	26,571.23	232.99	26,804.23	8.57453%	23-May-98
24-May-98	114,100,000.00	0.00	114,100,000.00	18,188.35	232.99	0.00	18,421.34	5.89289%	8.50000%	26,571.23	232.99	26,804.23	8.57453%	24-May-98
25-May-98	114,100,000.00	0.00	114,100,000.00	18,188.35	232.99	0.00	18,421.34	5.89289%	8.50000%	26,571.23	232.99	26,804.23	8.57453%	25-May-98
26-May-98	128,900,000.00	0.00	128,900,000.00	20,795.93	208.33	0.00	21,004.26	5.94768%	8.50000%	30,017.81	208.33	30,226.14	8.55899%	26-May-98
27-May-98	130,400,000.00	0.00	130,400,000.00	21,121.38	208.33	0.00	21,329.71	5.97036%	8.50000%	30,367.12	208.33	30,575.46	8.55831%	27-May-98
28-May-98	129,600,000.00	0.00	129,600,000.00	21,047.47	208.33	0.00	21,255.80	5.98640%	8.50000%	30,180.82	208.33	30,389.16	8.55867%	28-May-98
29-May-98	133,300,000.00	0.00	133,300,000.00	21,903.32	208.33	0.00	22,111.65	6.05458%	8.50000%	31,042.47	208.33	31,250.80	8.55705%	29-May-98
30-May-98	133,300,000.00	0.00	133,300,000.00	21,903.32	208.33	0.00	22,111.65	6.05458%	8.50000%	31,042.47	208.33	31,250.80	8.55705%	30-May-98
31-May-98	133,300,000.00	0.00	133,300,000.00	21,903.32	208.33	0.00	22,111.65	6.05458%	8.50000%	31,042.47	208.33	31,250.80	8.55705%	31-May-98
				610,583.45	6,684.59	0.00	617,268.04			883,580.82	6,684.59	890,265.42		

133,300,000.00		133,300,000.00	Maximum Outstanding During Month		
111,700,000.00		111,700,000.00	Minimum Outstanding During Month		
122,393,548.39	0.00	122,393,548.39	Month-to-Date Average Oustanding	92,025,806.45	
		617,268.04	Net Month-to-Date Interest Expense/(Income)	890,265.42	
5.9381%	N.A.	5.9381%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	11.3905%	(5)
5.8738%		5.8738%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month, If There is Net Income, This Computation is Not Applicable

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 28-Jun-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Jun-98	134,700,000.00	0.00	134,700,000.00	22,129.07	208.33	0.00	22,337.40	6.05282%	8.50000%	31,368.49	208.33	31,576.83	8.55645%	01-Jun-98
02-Jun-98	138,900,000.00	0.00	138,900,000.00	22,592.78	208.33	0.00	22,801.11	5.99165%	8.50000%	32,346.58	208.33	32,554.91	8.55475%	02-Jun-98
03-Jun-98	137,500,000.00	0.00	137,500,000.00	22,387.99	208.33	0.00	22,596.32	5.99830%	8.50000%	32,020.55	208.33	32,228.88	8.55530%	03-Jun-98
04-Jun-98	135,400,000.00	0.00	135,400,000.00	21,879.68	208.33	0.00	22,088.01	5.95430%	8.50000%	31,531.51	208.33	31,739.84	8.55616%	04-Jun-98
05-Jun-98	137,200,000.00	0.00	137,200,000.00	21,972.89	208.33	0.00	22,181.22	5.90098%	8.50000%	31,950.68	208.33	32,159.02	8.55542%	05-Jun-98
06-Jun-98	137,200,000.00	0.00	137,200,000.00	21,972.89	208.33	0.00	22,181.22	5.90098%	8.50000%	31,950.68	208.33	32,159.02	8.55542%	06-Jun-98
07-Jun-98	137,200,000.00	0.00	137,200,000.00	21,972.89	208.33	0.00	22,181.22	5.90098%	8.50000%	31,950.68	208.33	32,159.02	8.55542%	07-Jun-98
08-Jun-98	135,800,000.00	0.00	135,800,000.00	21,825.45	208.33	0.00	22,033.78	5.92219%	8.50000%	31,624.66	208.33	31,832.99	8.55600%	08-Jun-98
09-Jun-98	140,900,000.00	0.00	140,900,000.00	22,566.16	166.67	0.00	22,732.83	5.88892%	8.50000%	32,812.33	166.67	32,979.00	8.54317%	09-Jun-98
10-Jun-98	138,100,000.00	0.00	138,100,000.00	22,112.79	166.67	0.00	22,279.46	5.88849%	8.50000%	32,160.27	166.67	32,326.94	8.54405%	10-Jun-98
11-Jun-98	135,800,000.00	0.00	135,800,000.00	21,893.91	179.20	0.00	22,073.11	5.93276%	8.50000%	31,624.66	179.20	31,803.85	8.54816%	11-Jun-98
12-Jun-98	131,900,000.00	0.00	131,900,000.00	21,331.36	187.22	0.00	21,518.58	5.95472%	8.50000%	30,716.44	187.22	30,903.66	8.55181%	12-Jun-98
13-Jun-98	131,900,000.00	0.00	131,900,000.00	21,331.36	187.22	0.00	21,518.58	5.95472%	8.50000%	30,716.44	187.22	30,903.66	8.55181%	13-Jun-98
14-Jun-98	131,900,000.00	0.00	131,900,000.00	21,331.36	187.22	0.00	21,518.58	5.95472%	8.50000%	30,716.44	187.22	30,903.66	8.55181%	14-Jun-98
15-Jun-98	140,400,000.00	0.00	140,400,000.00	22,979.85	166.67	0.00	23,146.52	6.01743%	8.50000%	32,695.89	166.67	32,862.56	8.54333%	15-Jun-98
16-Jun-98	138,900,000.00	0.00	138,900,000.00	22,609.83	183.33	0.00	22,793.16	5.98956%	8.50000%	32,346.58	183.33	32,529.91	8.54818%	16-Jun-98
17-Jun-98	136,800,000.00	0.00	136,800,000.00	22,293.77	183.33	0.00	22,477.10	5.99718%	8.50000%	31,857.53	183.33	32,040.87	8.54892%	17-Jun-98
18-Jun-98	136,000,000.00	0.00	136,000,000.00	21,995.27	183.33	0.00	22,178.60	5.95235%	8.50000%	31,671.23	183.33	31,854.57	8.54920%	18-Jun-98
19-Jun-98	136,400,000.00	0.00	136,400,000.00	21,869.65	194.63	0.00	22,064.28	5.90430%	8.50000%	31,764.38	194.63	31,959.02	8.55208%	19-Jun-98
20-Jun-98	136,400,000.00	0.00	136,400,000.00	21,869.65	194.63	0.00	22,064.28	5.90430%	8.50000%	31,764.38	194.63	31,959.02	8.55208%	20-Jun-98
21-Jun-98	136,400,000.00	0.00	136,400,000.00	21,869.65	194.63	0.00	22,064.28	5.90430%	8.50000%	31,764.38	194.63	31,959.02	8.55208%	21-Jun-98
22-Jun-98	144,200,000.00	0.00	144,200,000.00	23,216.88	183.33	0.00	23,400.21	5.92308%	8.50000%	33,580.82	183.33	33,764.16	8.54641%	22-Jun-98
23-Jun-98	142,900,000.00	0.00	142,900,000.00	22,924.90	191.33	0.00	23,116.23	5.90442%	8.50000%	33,278.08	191.33	33,469.41	8.54887%	23-Jun-98
24-Jun-98	141,200,000.00	0.00	141,200,000.00	22,579.35	166.67	0.00	22,746.02	5.87981%	8.50000%	32,882.19	166.67	33,048.86	8.54308%	24-Jun-98
25-Jun-98	158,200,000.00	0.00	158,200,000.00	25,655.72	166.67	0.00	25,822.39	5.95776%	8.50000%	36,841.10	166.67	37,007.76	8.53845%	25-Jun-98
26-Jun-98	155,800,000.00	0.00	155,800,000.00	25,551.29	166.67	0.00	25,717.96	6.02507%	8.50000%	36,282.19	166.67	36,448.86	8.53905%	26-Jun-98
27-Jun-98	155,800,000.00	0.00	155,800,000.00	25,551.29	166.67	0.00	25,717.96	6.02507%	8.50000%	36,282.19	166.67	36,448.86	8.53905%	27-Jun-98
28-Jun-98	155,800,000.00	0.00	155,800,000.00	25,551.29	166.67	0.00	25,717.96	6.02507%	8.50000%	36,282.19	166.67	36,448.86	8.53905%	28-Jun-98
29-Jun-98	155,800,000.00	0.00	155,800,000.00	25,974.48	166.67	0.00	26,141.15	6.12421%	8.50000%	36,282.19	166.67	36,448.86	8.53905%	29-Jun-98
30-Jun-98	164,000,000.00	0.00	164,000,000.00	28,003.88	125.00	0.00	28,128.88	6.26039%	8.50000%	38,191.78	125.00	38,316.78	8.52782%	30-Jun-98
				687,797.33	5,541.07	0.00	693,338.40			987,257.53	5,541.07	992,798.61		

164,000,000.00		164,000,000.00	Maximum Outstanding During Month		
131,900,000.00		131,900,000.00	Minimum Outstanding During Month		
141,313,333.33	0.00	141,313,333.33	Month-to-Date Average Oustanding	95,093,333.33	
		693,338.40	Net Month-to-Date Interest Expense/(Income)	992,798.61	
5.9694%	N.A	5.9694%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	12.7023%	(5)
5.9217%		5.9217%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month, If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Jul-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Jul-98	162,000,000.00	0.00	162,000,000.00	27,554.05	125.00	0.00	27,679.05	6.23633%	8.50000%	37,726.03	125.00	37,851.03	8.52816%	01-Jul-98
02-Jul-98	161,900,000.00	0.00	161,900,000.00	26,558.40	149.66	0.00	26,708.06	6.02127%	8.50000%	37,702.74	149.66	37,852.40	8.53374%	02-Jul-98
03-Jul-98	162,900,000.00	0.00	162,900,000.00	26,581.34	149.66	0.00	26,731.00	5.98945%	8.50000%	37,935.62	149.66	38,085.28	8.53353%	03-Jul-98
04-Jul-98	162,900,000.00	0.00	162,900,000.00	26,581.34	149.66	0.00	26,731.00	5.98945%	8.50000%	37,935.62	149.66	38,085.28	8.53353%	04-Jul-98
05-Jul-98	162,900,000.00	0.00	162,900,000.00	26,581.34	149.66	0.00	26,731.00	5.98945%	8.50000%	37,935.62	149.66	38,085.28	8.53353%	05-Jul-98
06-Jul-98	162,200,000.00	0.00	162,200,000.00	26,469.88	149.66	0.00	26,619.54	5.99022%	8.50000%	37,772.60	149.66	37,922.26	8.53368%	06-Jul-98
07-Jul-98	160,600,000.00	0.00	160,600,000.00	25,941.57	149.66	0.00	26,091.23	5.92983%	8.50000%	37,400.00	149.66	37,549.66	8.53401%	07-Jul-98
08-Jul-98	160,000,000.00	0.00	160,000,000.00	25,728.90	149.66	0.00	25,878.56	5.90355%	8.50000%	37,260.27	149.66	37,409.93	8.53414%	08-Jul-98
09-Jul-98	157,200,000.00	0.00	157,200,000.00	25,357.72	149.66	0.00	25,507.38	5.92252%	8.50000%	36,608.22	149.66	36,757.88	8.53475%	09-Jul-98
10-Jul-98	155,300,000.00	0.00	155,300,000.00	24,998.86	149.66	0.00	25,148.52	5.91063%	8.50000%	36,165.75	149.66	36,315.41	8.53517%	10-Jul-98
11-Jul-98	155,300,000.00	0.00	155,300,000.00	24,998.86	149.66	0.00	25,148.52	5.91063%	8.50000%	36,165.75	149.66	36,315.41	8.53517%	11-Jul-98
12-Jul-98	155,300,000.00	0.00	155,300,000.00	24,998.86	149.66	0.00	25,148.52	5.91063%	8.50000%	36,165.75	149.66	36,315.41	8.53517%	12-Jul-98
13-Jul-98	154,500,000.00	0.00	154,500,000.00	25,001.32	149.66	0.00	25,150.98	5.94182%	8.50000%	35,979.45	149.66	36,129.11	8.53536%	13-Jul-98
14-Jul-98	151,900,000.00	0.00	151,900,000.00	24,498.00	149.66	0.00	24,647.66	5.92258%	8.50000%	35,373.97	149.66	35,523.63	8.53596%	14-Jul-98
15-Jul-98	150,700,000.00	0.00	150,700,000.00	24,564.47	125.00	0.00	24,689.47	5.97986%	8.50000%	35,094.52	125.00	35,219.52	8.53028%	15-Jul-98
16-Jul-98	150,600,000.00	0.00	150,600,000.00	24,392.09	149.66	0.00	24,541.75	5.94803%	8.50000%	35,071.23	149.66	35,220.89	8.53627%	16-Jul-98
17-Jul-98	152,600,000.00	0.00	152,600,000.00	24,570.11	149.66	0.00	24,719.77	5.91266%	8.50000%	35,536.99	149.66	35,686.65	8.53580%	17-Jul-98
18-Jul-98	152,600,000.00	0.00	152,600,000.00	24,570.11	149.66	0.00	24,719.77	5.91266%	8.50000%	35,536.99	149.66	35,686.65	8.53580%	18-Jul-98
19-Jul-98	152,600,000.00	0.00	152,600,000.00	24,570.11	149.66	0.00	24,719.77	5.91266%	8.50000%	35,536.99	149.66	35,686.65	8.53580%	19-Jul-98
20-Jul-98	158,400,000.00	0.00	158,400,000.00	25,549.91	149.66	0.00	25,699.57	5.92193%	8.50000%	36,887.67	149.66	37,037.33	8.53449%	20-Jul-98
21-Jul-98	155,600,000.00	0.00	155,600,000.00	25,030.22	149.66	0.00	25,179.88	5.90659%	8.50000%	36,235.62	149.66	36,385.28	8.53511%	21-Jul-98
22-Jul-98	154,900,000.00	0.00	154,900,000.00	24,930.46	149.66	0.00	25,080.12	5.90978%	8.50000%	36,072.60	149.66	36,222.26	8.53527%	22-Jul-98
23-Jul-98	154,100,000.00	0.00	154,100,000.00	24,938.70	149.66	0.00	25,088.36	5.94241%	8.50000%	35,886.30	149.66	36,035.96	8.53545%	23-Jul-98
24-Jul-98	164,000,000.00	0.00	164,000,000.00	26,416.38	130.96	0.00	26,547.34	5.90840%	8.50000%	38,191.78	130.96	38,322.74	8.52915%	24-Jul-98
25-Jul-98	164,000,000.00	0.00	164,000,000.00	26,416.38	130.96	0.00	26,547.34	5.90840%	8.50000%	38,191.78	130.96	38,322.74	8.52915%	25-Jul-98
26-Jul-98	164,000,000.00	0.00	164,000,000.00	26,416.38	130.96	0.00	26,547.34	5.90840%	8.50000%	38,191.78	130.96	38,322.74	8.52915%	26-Jul-98
27-Jul-98	117,300,000.00	100,000,000.00	17,300,000.00	19,019.58	149.66	15,277.78	3,891.46	8.21031%	8.50000%	4,028.77	149.66	4,178.43	8.81576%	27-Jul-98
28-Jul-98	17,200,000.00	0.00	17,200,000.00	2,823.67	316.33	0.00	3,140.00	6.66337%	8.50000%	4,005.48	316.33	4,321.81	9.17127%	28-Jul-98
29-Jul-98	17,400,000.00	0.00	17,400,000.00	2,856.50	316.33	0.00	3,172.83	6.65564%	8.50000%	4,052.05	316.33	4,368.38	9.16356%	29-Jul-98
30-Jul-98	16,200,000.00	0.00	16,200,000.00	2,632.50	316.33	0.00	2,948.83	6.64396%	8.50000%	3,772.60	316.33	4,088.93	9.21271%	30-Jul-98
31-Jul-98	30,100,000.00	0.00	30,100,000.00	4,938.59	316.33	0.00	5,254.92	6.37224%	8.50000%	7,009.59	316.33	7,325.92	8.88359%	31-Jul-98
				696,486.60	5,200.71	15,277.78	686,409.53			977,430.14	5,200.71	982,630.84		

164,000,000.00		164,000,000.00	Maximum Outstanding During Month		
16,200,000.00		16,200,000.00	Minimum Outstanding During Month		
138,619,354.84	3,225,806.45	135,393,548.39	Month-to-Date Average Oustanding	92,025,806.45	
		686,409.53	Net Month-to-Date Interest Expense/(Income)	982,630.84	
5.9601%	-5.5764%	5.9692%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	12.5722%	(5)
5.9159%		5.9240%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income. This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Aug-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S. T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Aug-98	30,100,000.00	0.00	30,100,000.00	4,938.59	316.33	0.00	5,254.92	6.37224%	8.50000%	7,009.59	316.33	7,325.92	8.88359%	01-Aug-98
02-Aug-98	30,100,000.00	0.00	30,100,000.00	4,938.59	316.33	0.00	5,254.92	6.37224%	8.50000%	7,009.59	316.33	7,325.92	8.88359%	02-Aug-98
03-Aug-98	30,300,000.00	0.00	30,300,000.00	4,938.19	316.33	0.00	5,254.52	6.32970%	8.50000%	7,056.16	316.33	7,372.49	8.88105%	03-Aug-98
04-Aug-98	31,000,000.00	0.00	31,000,000.00	4,977.23	316.33	0.00	5,293.56	6.23274%	8.50000%	7,219.18	316.33	7,535.50	8.87245%	04-Aug-98
05-Aug-98	31,100,000.00	0.00	31,100,000.00	4,938.33	316.33	0.00	5,254.66	6.16704%	8.50000%	7,242.47	316.33	7,558.79	8.87125%	05-Aug-98
06-Aug-98	30,100,000.00	0.00	30,100,000.00	4,846.89	316.33	0.00	5,163.22	6.26104%	8.50000%	7,009.59	316.33	7,325.92	8.88359%	06-Aug-98
07-Aug-98	29,700,000.00	0.00	29,700,000.00	4,682.97	441.33	0.00	5,124.30	6.29754%	8.50000%	6,916.44	441.33	7,357.77	9.04237%	07-Aug-98
08-Aug-98	29,700,000.00	0.00	29,700,000.00	4,682.97	441.33	0.00	5,124.30	6.29754%	8.50000%	6,916.44	441.33	7,357.77	9.04237%	08-Aug-98
09-Aug-98	29,700,000.00	0.00	29,700,000.00	4,682.97	441.33	0.00	5,124.30	6.29754%	8.50000%	6,916.44	441.33	7,357.77	9.04237%	09-Aug-98
10-Aug-98	29,300,000.00	0.00	29,300,000.00	4,710.76	416.67	0.00	5,127.43	6.38741%	8.50000%	6,823.29	416.67	7,239.95	9.01906%	10-Aug-98
11-Aug-98	25,400,000.00	0.00	25,400,000.00	4,030.22	441.33	0.00	4,471.55	6.42565%	8.50000%	5,915.07	441.33	6,356.40	9.13419%	11-Aug-98
12-Aug-98	20,100,000.00	0.00	20,100,000.00	3,249.32	416.67	0.00	3,665.99	6.65714%	8.50000%	4,680.82	416.67	5,097.49	9.25663%	12-Aug-98
13-Aug-98	19,100,000.00	0.00	19,100,000.00	3,066.61	441.33	0.00	3,507.94	6.70365%	8.50000%	4,447.95	441.33	4,889.27	9.34337%	13-Aug-98
14-Aug-98	20,700,000.00	0.00	20,700,000.00	3,349.71	416.67	0.00	3,766.38	6.64120%	8.50000%	4,820.55	416.67	5,237.21	9.23470%	14-Aug-98
15-Aug-98	20,700,000.00	0.00	20,700,000.00	3,349.71	416.67	0.00	3,766.38	6.64120%	8.50000%	4,820.55	416.67	5,237.21	9.23470%	15-Aug-98
16-Aug-98	20,700,000.00	0.00	20,700,000.00	3,349.71	416.67	0.00	3,766.38	6.64120%	8.50000%	4,820.55	416.67	5,237.21	9.23470%	16-Aug-98
17-Aug-98	21,800,000.00	0.00	21,800,000.00	3,597.00	416.67	0.00	4,013.67	6.72013%	8.50000%	5,076.71	416.67	5,493.38	9.19763%	17-Aug-98
18-Aug-98	20,800,000.00	0.00	20,800,000.00	3,336.77	441.33	0.00	3,778.10	6.62983%	8.50000%	4,843.84	441.33	5,285.16	9.27444%	18-Aug-98
19-Aug-98	19,500,000.00	0.00	19,500,000.00	3,092.92	441.33	0.00	3,534.25	6.61538%	8.50000%	4,541.10	441.33	4,982.42	9.32607%	19-Aug-98
20-Aug-98	19,200,000.00	0.00	19,200,000.00	3,050.67	441.33	0.00	3,492.00	6.63843%	8.50000%	4,471.23	441.33	4,912.56	9.33898%	20-Aug-98
21-Aug-98	19,700,000.00	0.00	19,700,000.00	3,130.11	441.33	0.00	3,571.44	6.61713%	8.50000%	4,587.67	441.33	5,029.00	9.31769%	21-Aug-98
22-Aug-98	19,700,000.00	0.00	19,700,000.00	3,130.11	441.33	0.00	3,571.44	6.61713%	8.50000%	4,587.67	441.33	5,029.00	9.31769%	22-Aug-98
23-Aug-98	19,700,000.00	0.00	19,700,000.00	3,130.11	441.33	0.00	3,571.44	6.61713%	8.50000%	4,587.67	441.33	5,029.00	9.31769%	23-Aug-98
24-Aug-98	19,700,000.00	0.00	19,700,000.00	3,157.47	441.33	0.00	3,598.80	6.66782%	8.50000%	4,587.67	441.33	5,029.00	9.31769%	24-Aug-98
25-Aug-98	33,200,000.00	0.00	33,200,000.00	5,265.89	441.33	0.00	5,707.22	6.27450%	8.50000%	7,731.51	441.33	8,172.83	8.98519%	25-Aug-98
26-Aug-98	32,200,000.00	0.00	32,200,000.00	5,277.22	441.33	0.00	5,718.55	6.48220%	8.50000%	7,498.63	441.33	7,939.96	9.00026%	26-Aug-98
27-Aug-98	28,600,000.00	0.00	28,600,000.00	4,583.94	441.33	0.00	5,025.27	6.41336%	8.50000%	6,660.27	441.33	7,101.60	9.06323%	27-Aug-98
28-Aug-98	29,500,000.00	0.00	29,500,000.00	4,746.16	416.67	0.00	5,162.83	6.38790%	8.50000%	6,869.86	416.67	7,286.53	9.01554%	28-Aug-98
29-Aug-98	29,500,000.00	0.00	29,500,000.00	4,746.16	416.67	0.00	5,162.83	6.38790%	8.50000%	6,869.86	416.67	7,286.53	9.01554%	29-Aug-98
30-Aug-98	29,500,000.00	0.00	29,500,000.00	4,746.16	416.67	0.00	5,162.83	6.38790%	8.50000%	6,869.86	416.67	7,286.53	9.01554%	30-Aug-98
31-Aug-98	34,300,000.00	0.00	34,300,000.00	5,783.19	416.67	0.00	6,199.86	6.59752%	8.50000%	7,987.67	416.67	8,404.34	8.94339%	31-Aug-98
				129,506.65	12,684.53	0.00	142,191.18			187,395.89	12,684.53	200,080.42		

34,300,000.00		34,300,000.00	Maximum Outstanding During Month		
19,100,000.00		19,100,000.00	Minimum Outstanding During Month		
25,958,064.52	0.00	25,958,064.52	Month-to-Date Average Oustanding	92,025,806.45	
		142,191.18	Net Month-to-Date Interest Expense/(Income)	200,080.42	
6.4496%	N.A.	6.4496%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	2.5599%	(5)
5.8742%		5.8742%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month: If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 30-Sep-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Sep-98	47,200,000.00	0.00	47,200,000.00	7,953.33	441.33	0.00	8,394.66	6.49163%	8.50000%	10,991.78	441.33	11,433.11	8.84128%	01-Sep-98
02-Sep-98	46,900,000.00	0.00	46,900,000.00	7,572.78	441.33	0.00	8,014.11	6.23699%	8.50000%	10,921.92	441.33	11,363.24	8.84346%	02-Sep-98
03-Sep-98	45,900,000.00	0.00	45,900,000.00	7,389.13	416.67	0.00	7,805.80	6.20722%	8.50000%	10,689.04	416.67	11,105.71	8.83134%	03-Sep-98
04-Sep-98	47,400,000.00	0.00	47,400,000.00	7,525.06	416.67	0.00	7,941.73	6.11546%	8.50000%	11,038.36	416.67	11,455.02	8.82085%	04-Sep-98
05-Sep-98	47,400,000.00	0.00	47,400,000.00	7,525.06	416.67	0.00	7,941.73	6.11546%	8.50000%	11,038.36	416.67	11,455.02	8.82085%	05-Sep-98
06-Sep-98	47,400,000.00	0.00	47,400,000.00	7,525.06	416.67	0.00	7,941.73	6.11546%	8.50000%	11,038.36	416.67	11,455.02	8.82085%	06-Sep-98
07-Sep-98	47,400,000.00	0.00	47,400,000.00	7,525.06	416.67	0.00	7,941.73	6.11546%	8.50000%	11,038.36	416.67	11,455.02	8.82085%	07-Sep-98
08-Sep-98	46,300,000.00	0.00	46,300,000.00	7,485.13	416.67	0.00	7,901.80	6.22928%	8.50000%	10,782.19	416.67	11,198.86	8.82847%	08-Sep-98
09-Sep-98	50,100,000.00	0.00	50,100,000.00	8,342.49	416.67	0.00	8,759.16	6.38142%	8.50000%	11,667.12	416.67	12,083.79	8.80356%	09-Sep-98
10-Sep-98	49,700,000.00	0.00	49,700,000.00	8,065.37	416.67	0.00	8,482.04	6.22926%	8.50000%	11,573.97	416.67	11,990.64	8.80600%	10-Sep-98
11-Sep-98	49,700,000.00	0.00	49,700,000.00	7,928.56	416.67	0.00	8,345.23	6.12879%	8.50000%	11,573.97	416.67	11,990.64	8.80600%	11-Sep-98
12-Sep-98	49,700,000.00	0.00	49,700,000.00	7,928.56	416.67	0.00	8,345.23	6.12879%	8.50000%	11,573.97	416.67	11,990.64	8.80600%	12-Sep-98
13-Sep-98	49,700,000.00	0.00	49,700,000.00	7,928.56	416.67	0.00	8,345.23	6.12879%	8.50000%	11,573.97	416.67	11,990.64	8.80600%	13-Sep-98
14-Sep-98	42,800,000.00	0.00	42,800,000.00	6,980.93	416.67	0.00	7,397.60	6.30870%	8.50000%	9,967.12	416.67	10,383.79	8.85533%	14-Sep-98
15-Sep-98	47,500,000.00	0.00	47,500,000.00	8,093.07	416.67	0.00	8,509.74	6.53906%	8.50000%	11,061.64	416.67	11,478.31	8.82018%	15-Sep-98
16-Sep-98	50,900,000.00	0.00	50,900,000.00	8,201.31	441.33	0.00	8,642.64	6.19757%	8.50000%	11,853.42	441.33	12,294.75	8.81647%	16-Sep-98
17-Sep-98	50,800,000.00	0.00	50,800,000.00	8,156.00	441.33	0.00	8,597.33	6.17721%	8.50000%	11,830.14	441.33	12,271.46	8.81709%	17-Sep-98
18-Sep-98	49,500,000.00	0.00	49,500,000.00	7,782.50	441.33	0.00	8,223.83	6.06403%	8.50000%	11,527.40	441.33	11,968.72	8.82542%	18-Sep-98
19-Sep-98	49,500,000.00	0.00	49,500,000.00	7,782.50	441.33	0.00	8,223.83	6.06403%	8.50000%	11,527.40	441.33	11,968.72	8.82542%	19-Sep-98
20-Sep-98	49,500,000.00	0.00	49,500,000.00	7,782.50	441.33	0.00	8,223.83	6.06403%	8.50000%	11,527.40	441.33	11,968.72	8.82542%	20-Sep-98
21-Sep-98	43,700,000.00	0.00	43,700,000.00	6,961.24	416.67	0.00	7,377.91	6.16232%	8.50000%	10,176.71	416.67	10,593.38	8.84802%	21-Sep-98
22-Sep-98	40,800,000.00	0.00	40,800,000.00	6,519.01	416.67	0.00	6,935.68	6.20471%	8.50000%	9,501.37	416.67	9,918.04	8.87275%	22-Sep-98
23-Sep-98	40,000,000.00	0.00	40,000,000.00	6,361.11	416.67	0.00	6,777.78	6.18472%	8.50000%	9,315.07	416.67	9,731.74	8.88021%	23-Sep-98
24-Sep-98	37,700,000.00	0.00	37,700,000.00	6,009.46	416.67	0.00	6,426.13	6.22158%	8.50000%	8,779.45	416.67	9,196.12	8.90340%	24-Sep-98
25-Sep-98	49,700,000.00	0.00	49,700,000.00	7,800.14	441.33	0.00	8,241.47	6.05259%	8.50000%	11,573.97	441.33	12,015.30	8.82411%	25-Sep-98
26-Sep-98	49,700,000.00	0.00	49,700,000.00	7,800.14	441.33	0.00	8,241.47	6.05259%	8.50000%	11,573.97	441.33	12,015.30	8.82411%	26-Sep-98
27-Sep-98	49,700,000.00	0.00	49,700,000.00	7,800.14	441.33	0.00	8,241.47	6.05259%	8.50000%	11,573.97	441.33	12,015.30	8.82411%	27-Sep-98
28-Sep-98	52,600,000.00	0.00	52,600,000.00	8,437.55	441.33	0.00	8,878.88	6.16120%	8.50000%	12,249.32	441.33	12,690.64	8.80624%	28-Sep-98
29-Sep-98	52,700,000.00	0.00	52,700,000.00	8,391.08	441.33	0.00	8,832.41	6.11732%	8.50000%	12,272.60	441.33	12,713.93	8.80566%	29-Sep-98
30-Sep-98	66,400,000.00	2,000,000.00	64,400,000.00	11,187.81	416.67	305.00	11,299.48	6.40421%	8.50000%	14,997.26	416.67	15,413.93	8.73615%	30-Sep-98
				232,740.64	12,795.92	305.00	245,231.56			336,809.59	12,795.92	349,605.51		

66,400,000.00		64,400,000.00	Maximum Outstanding During Month		
37,700,000.00		37,700,000.00	Minimum Outstanding During Month		
48,276,666.67	66,666.67	48,210,000.00	Month-to-Date Average Outstanding	95,093,333.33	
		245,231.56	Net Month-to-Date Interest Expense/(Income)	349,605.51	
6.1880%	-5.5663%	6.1889%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	4.4730%	(5)
5.8655%		5.8659%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month: If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. PRUDHOMME

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Oct-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Oct-98	62,600,000.00	0.00	62,600,000.00	10,192.78	441.33	0.00	10,634.11	6.20040%	8.25000%	14,149.32	441.33	14,590.64	8.50732%	01-Oct-98
02-Oct-98	61,300,000.00	0.00	61,300,000.00	9,821.27	441.33	0.00	10,262.60	6.11068%	8.25000%	13,855.48	441.33	14,296.81	8.51278%	02-Oct-98
03-Oct-98	61,300,000.00	0.00	61,300,000.00	9,821.27	441.33	0.00	10,262.60	6.11068%	8.25000%	13,855.48	441.33	14,296.81	8.51278%	03-Oct-98
04-Oct-98	61,300,000.00	0.00	61,300,000.00	9,821.27	441.33	0.00	10,262.60	6.11068%	8.25000%	13,855.48	441.33	14,296.81	8.51278%	04-Oct-98
05-Oct-98	60,800,000.00	0.00	60,800,000.00	9,697.34	416.67	0.00	10,114.01	6.07173%	8.25000%	13,742.47	416.67	14,159.13	8.50014%	05-Oct-98
06-Oct-98	59,700,000.00	0.00	59,700,000.00	9,563.77	416.67	0.00	9,980.44	6.10194%	8.25000%	13,493.84	416.67	13,910.50	8.50475%	06-Oct-98
07-Oct-98	59,700,000.00	0.00	59,700,000.00	9,144.28	416.67	0.00	9,560.95	5.84547%	8.25000%	13,493.84	416.67	13,910.50	8.50475%	07-Oct-98
08-Oct-98	61,500,000.00	0.00	61,500,000.00	9,316.30	416.67	0.00	9,732.97	5.77648%	8.25000%	13,900.68	416.67	14,317.35	8.49729%	08-Oct-98
09-Oct-98	67,600,000.00	0.00	67,600,000.00	10,046.12	441.33	0.00	10,487.45	5.66260%	8.25000%	15,279.45	441.33	15,720.78	8.48829%	09-Oct-98
10-Oct-98	67,600,000.00	0.00	67,600,000.00	10,046.12	441.33	0.00	10,487.45	5.66260%	8.25000%	15,279.45	441.33	15,720.78	8.48829%	10-Oct-98
11-Oct-98	67,600,000.00	0.00	67,600,000.00	10,046.12	441.33	0.00	10,487.45	5.66260%	8.25000%	15,279.45	441.33	15,720.78	8.48829%	11-Oct-98
12-Oct-98	67,600,000.00	0.00	67,600,000.00	10,046.12	441.33	0.00	10,487.45	5.66260%	8.25000%	15,279.45	441.33	15,720.78	8.48829%	12-Oct-98
1[illegible]98	68,700,000.00	0.00	68,700,000.00	10,474.49	416.67	0.00	10,891.16	5.78642%	8.25000%	15,528.08	416.67	15,944.75	8.47137%	13-Oct-98
14-Oct-98	66,200,000.00	0.00	66,200,000.00	10,335.72	441.33	0.00	10,777.05	5.94203%	8.25000%	14,963.01	441.33	15,404.34	8.49333%	14-Oct-98
15-Oct-98	64,100,000.00	0.00	64,100,000.00	10,373.10	416.67	0.00	10,789.77	6.14394%	8.25000%	14,488.36	416.67	14,905.02	8.48726%	15-Oct-98
16-Oct-98	63,400,000.00	0.00	63,400,000.00	9,430.39	441.33	0.00	9,871.72	5.68324%	8.00000%	13,895.89	441.33	14,337.22	8.25408%	16-Oct-98
17-Oct-98	63,400,000.00	0.00	63,400,000.00	9,430.39	441.33	0.00	9,871.72	5.68324%	8.00000%	13,895.89	441.33	14,337.22	8.25408%	17-Oct-98
18-Oct-98	63,400,000.00	0.00	63,400,000.00	9,430.39	441.33	0.00	9,871.72	5.68324%	8.00000%	13,895.89	441.33	14,337.22	8.25408%	18-Oct-98
19-Oct-98	63,000,000.00	0.00	63,000,000.00	9,293.05	441.33	0.00	9,734.38	5.63976%	8.00000%	13,808.22	441.33	14,249.55	8.25569%	19-Oct-98
20-Oct-98	62,800,000.00	0.00	62,800,000.00	9,105.00	441.33	0.00	9,546.33	5.54842%	8.00000%	13,764.38	441.33	14,205.71	8.25650%	20-Oct-98
21-Oct-98	62,100,000.00	0.00	62,100,000.00	9,115.61	441.33	0.00	9,556.94	5.61720%	8.00000%	13,610.96	441.33	14,052.29	8.25939%	21-Oct-98
22-Oct-98	65,800,000.00	0.00	65,800,000.00	9,582.67	441.33	0.00	10,024.00	5.56042%	8.00000%	14,421.92	441.33	14,863.24	8.24481%	22-Oct-98
23-Oct-98	71,800,000.00	0.00	71,800,000.00	10,286.24	437.63	0.00	10,723.87	5.45155%	8.00000%	15,736.99	437.63	16,174.61	8.22247%	23-Oct-98
24-Oct-98	71,800,000.00	0.00	71,800,000.00	10,286.24	437.63	0.00	10,723.87	5.45155%	8.00000%	15,736.99	437.63	16,174.61	8.22247%	24-Oct-98
25-Oct-98	71,800,000.00	0.00	71,800,000.00	10,286.24	437.63	0.00	10,723.87	5.45155%	8.00000%	15,736.99	437.63	16,174.61	8.22247%	25-Oct-98
26-Oct-98	74,400,000.00	0.00	74,400,000.00	10,869.19	432.29	0.00	11,301.48	5.54441%	8.00000%	16,306.85	432.29	16,739.14	8.21208%	26-Oct-98
27-Oct-98	74,800,000.00	0.00	74,800,000.00	11,022.99	431.46	0.00	11,454.45	5.58940%	8.00000%	16,394.52	431.46	16,825.98	8.21054%	27-Oct-98
28-Oct-98	74,600,000.00	0.00	74,600,000.00	11,578.27	441.33	0.00	12,019.60	5.88090%	8.00000%	16,350.68	441.33	16,792.01	8.21593%	28-Oct-98
29-Oct-98	75,600,000.00	0.00	75,600,000.00	11,768.02	416.67	0.00	12,184.69	5.88282%	8.00000%	16,569.86	416.67	16,986.53	8.20117%	29-Oct-98
30-Oct-98	81,400,000.00	0.00	81,400,000.00	12,764.76	416.67	0.00	13,181.43	5.91059%	8.00000%	17,841.10	416.67	18,257.76	8.18683%	30-Oct-98
31-[illegible]98	81,400,000.00	0.00	81,400,000.00	12,764.76	416.67	0.00	13,181.43	5.91059%	8.00000%	17,841.10	416.67	18,257.76	8.18683%	31-Oct-98
				315,760.28	13,429.18	0.00	329,189.46			462,252.05	13,429.18	475,681.23		

81,400,000.00		81,400,000.00	Maximum Outstanding During Month		
59,700,000.00		59,700,000.00	Minimum Outstanding During Month		
67,067,741.94	0.00	64,441,935.48	Month-to-Date Average Oustanding	92,025,806.45	
		329,189.46	Net Month-to-Date Interest Expense/(Income)	475,681.23	
5.7791%	N.A.	6.0146%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	6.0861%	(5)
5.5434%		5.7693%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actua[illegible]er of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 30-Nov-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Nov-98	81,400,000.00	0.00	81,400,000.00	12,764.76	416.67	0.00	13,181.43	5.91059%	8.00000%	17,841.10	416.67	18,257.76	8.18683%	01-Nov-98
02-Nov-98	82,100,000.00	0.00	82,100,000.00	12,971.42	416.67	0.00	13,388.09	5.95207%	8.00000%	17,994.52	416.67	18,411.19	8.18524%	02-Nov-98
03-Nov-98	81,500,000.00	0.00	81,500,000.00	12,892.13	416.67	0.00	13,308.80	5.96038%	8.00000%	17,863.01	416.67	18,279.68	8.18661%	03-Nov-98
04-Nov-98	80,900,000.00	0.00	80,900,000.00	12,606.78	416.67	0.00	13,023.45	5.87584%	8.00000%	17,731.51	416.67	18,148.17	8.18799%	04-Nov-98
05-Nov-98	80,100,000.00	0.00	80,100,000.00	12,435.20	416.67	0.00	12,851.87	5.85634%	8.00000%	17,556.16	416.67	17,972.83	8.18987%	05-Nov-98
06-Nov-98	83,200,000.00	0.00	83,200,000.00	12,756.66	441.33	0.00	13,197.99	5.78998%	8.00000%	18,235.62	441.33	18,676.94	8.19361%	06-Nov-98
07-Nov-98	83,200,000.00	0.00	83,200,000.00	12,756.66	441.33	0.00	13,197.99	5.78998%	8.00000%	18,235.62	441.33	18,676.94	8.19361%	07-Nov-98
08-Nov-98	83,200,000.00	0.00	83,200,000.00	12,756.66	441.33	0.00	13,197.99	5.78998%	8.00000%	18,235.62	441.33	18,676.94	8.19361%	08-Nov-98
09-Nov-98	83,200,000.00	0.00	83,200,000.00	12,783.13	416.67	0.00	13,199.80	5.79078%	8.00000%	18,235.62	416.67	18,652.28	8.18279%	09-Nov-98
10-Nov-98	83,300,000.00	0.00	83,300,000.00	12,818.25	416.67	0.00	13,234.92	5.79921%	8.00000%	18,257.53	416.67	18,674.20	8.18257%	10-Nov-98
11-Nov-98	83,300,000.00	0.00	83,300,000.00	12,818.29	416.67	0.00	13,234.96	5.79923%	8.00000%	18,257.53	416.67	18,674.20	8.18257%	11-Nov-98
12-Nov-98	85,100,000.00	0.00	85,100,000.00	13,115.61	416.67	0.00	13,532.28	5.80409%	8.00000%	18,652.05	416.67	19,068.72	8.17871%	12-Nov-98
13-Nov-98	82,900,000.00	0.00	82,900,000.00	12,792.89	416.67	0.00	13,209.56	5.81603%	8.00000%	18,169.86	416.67	18,586.53	8.18345%	13-Nov-98
14-Nov-98	82,900,000.00	0.00	82,900,000.00	12,792.89	416.67	0.00	13,209.56	5.81603%	8.00000%	18,169.86	416.67	18,586.53	8.18345%	14-Nov-98
15-Nov-98	82,900,000.00	0.00	82,900,000.00	12,792.89	416.67	0.00	13,209.56	5.81603%	8.00000%	18,169.86	416.67	18,586.53	8.18345%	15-Nov-98
16-Nov-98	81,800,000.00	0.00	81,800,000.00	12,895.01	416.67	0.00	13,311.68	5.93981%	8.00000%	17,928.77	416.67	18,345.43	8.18592%	16-Nov-98
17-Nov-98	81,000,000.00	0.00	81,000,000.00	12,608.33	441.33	0.00	13,049.66	5.88040%	7.75000%	17,198.63	441.33	17,639.96	7.94887%	17-Nov-98
18-Nov-98	79,900,000.00	0.00	79,900,000.00	12,238.80	441.33	0.00	12,680.13	5.79255%	7.75000%	16,965.07	441.33	17,406.40	7.95161%	18-Nov-98
19-Nov-98	79,100,000.00	0.00	79,100,000.00	11,608.64	416.67	0.00	12,025.31	5.54897%	7.75000%	16,795.21	416.67	17,211.87	7.94227%	19-Nov-98
20-Nov-98	84,200,000.00	0.00	84,200,000.00	11,993.06	441.33	0.00	12,434.39	5.39020%	7.75000%	17,878.08	441.33	18,319.41	7.94131%	20-Nov-98
21-Nov-98	84,200,000.00	0.00	84,200,000.00	11,843.07	441.33	0.00	12,284.40	5.32518%	7.75000%	17,878.08	441.33	18,319.41	7.94131%	21-Nov-98
22-Nov-98	84,200,000.00	0.00	84,200,000.00	11,843.06	441.33	0.00	12,284.39	5.32518%	7.75000%	17,878.08	441.33	18,319.41	7.94131%	22-Nov-98
23-Nov-98	83,500,000.00	0.00	83,500,000.00	11,912.37	441.33	0.00	12,353.70	5.40012%	7.75000%	17,729.45	441.33	18,170.78	7.94292%	23-Nov-98
24-Nov-98	89,900,000.00	0.00	89,900,000.00	12,751.03	441.33	0.00	13,192.36	5.35618%	7.75000%	19,088.36	441.33	19,529.68	7.92918%	24-Nov-98
25-Nov-98	134,700,000.00	0.00	134,700,000.00	19,805.99	416.67	0.00	20,222.66	5.47978%	7.75000%	28,600.68	416.67	29,017.35	7.86291%	25-Nov-98
26-Nov-98	134,700,000.00	0.00	134,700,000.00	19,805.98	416.67	0.00	20,222.65	5.47978%	7.75000%	28,600.68	416.67	29,017.35	7.86291%	26-Nov-98
27-Nov-98	134,200,000.00	0.00	134,200,000.00	19,901.30	416.67	0.00	20,317.97	5.52612%	7.75000%	28,494.52	416.67	28,911.19	7.86333%	27-Nov-98
28-Nov-98	134,200,000.00	0.00	134,200,000.00	19,901.30	416.67	0.00	20,317.97	5.52612%	7.75000%	28,494.52	416.67	28,911.19	7.86333%	28-Nov-98
29-Nov-98	134,200,000.00	0.00	134,200,000.00	19,901.30	416.67	0.00	20,317.97	5.52612%	7.75000%	28,494.52	416.67	28,911.19	7.86333%	29-Nov-98
30-Nov-98	135,700,000.00	0.00	135,700,000.00	21,036.82	416.67	0.00	21,453.49	5.77047%	7.75000%	28,813.01	416.67	29,229.68	7.86207%	30-Nov-98
				421,900.28	12,746.60	0.00	434,646.88			602,443.15	12,746.60	615,189.75		

135,700,000.00		135,700,000.00	Maximum Outstanding During Month	
79,100,000.00		79,100,000.00	Minimum Outstanding During Month	
93,156,666.67	0.00	93,156,666.67	Month-to-Date Average Oustanding	95,093,333.33
		434,646.88	Net Month-to-Date Interest Expense/(Income)	615,189.75
5.6767%	N.A.	5.6767%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	7.8710% (5)
5.5102%		5.5102%	Above Rates Net of Commitment Fees	

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Dec-98

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Dec-98	132,300,000.00	0.00	132,300,000.00	19,633.48	426.33	0.00	20,059.81	5.53426%	8.00000%	28,997.26	426.33	29,423.59	8.11762%	01-Dec-98
02-Dec-98	131,800,000.00	0.00	131,800,000.00	18,736.93	427.35	0.00	19,164.28	5.30725%	8.00000%	28,887.67	427.35	29,315.02	8.11835%	02-Dec-98
03-Dec-98	129,930,000.00	0.00	129,930,000.00	17,983.28	416.67	0.00	18,399.95	5.16892%	8.00000%	28,477.81	416.67	28,894.47	8.11705%	03-Dec-98
04-Dec-98	132,830,000.00	0.00	132,830,000.00	18,327.25	416.67	0.00	18,743.92	5.15059%	8.00000%	29,113.42	416.67	29,530.09	8.11449%	04-Dec-98
05-Dec-98	132,830,000.00	0.00	132,830,000.00	18,327.25	416.67	0.00	18,743.92	5.15059%	8.00000%	29,113.42	416.67	29,530.09	8.11449%	05-Dec-98
06-Dec-98	132,830,000.00	0.00	132,830,000.00	18,327.25	416.67	0.00	18,743.92	5.15059%	8.00000%	29,113.42	416.67	29,530.09	8.11449%	06-Dec-98
07-Dec-98	132,530,000.00	0.00	132,530,000.00	18,565.36	416.67	0.00	18,982.03	5.22783%	8.00000%	29,047.67	416.67	29,464.34	8.11475%	07-Dec-98
08-Dec-98	130,630,000.00	0.00	130,630,000.00	18,222.65	416.67	0.00	18,639.32	5.20811%	8.00000%	28,631.23	416.67	29,047.90	8.11642%	08-Dec-98
09-Dec-98	139,430,000.00	0.00	139,430,000.00	20,047.01	441.33	0.00	20,488.34	5.36344%	8.00000%	30,560.00	441.33	31,001.33	8.11553%	09-Dec-98
10-Dec-98	135,800,000.00	0.00	135,800,000.00	19,939.47	441.33	0.00	20,380.80	5.47790%	8.00000%	29,764.38	441.33	30,205.71	8.11862%	10-Dec-98
11-Dec-98	139,500,000.00	2,300,000.00	137,200,000.00	20,644.98	441.33	323.28	20,763.03	5.52369%	8.00000%	30,071.23	441.33	30,512.56	8.11741%	11-Dec-98
12-Dec-98	139,500,000.00	2,300,000.00	137,200,000.00	20,645.00	441.33	323.28	20,763.05	5.52370%	8.00000%	30,071.23	441.33	30,512.56	8.11741%	12-Dec-98
13-Dec-98	139,500,000.00	2,300,000.00	137,200,000.00	20,645.00	441.33	323.28	20,763.05	5.52370%	8.00000%	30,071.23	441.33	30,512.56	8.11741%	13-Dec-98
14-Dec-98	135,500,000.00	0.00	135,500,000.00	20,254.14	419.75	0.00	20,673.89	5.56898%	8.00000%	29,698.63	419.75	30,118.38	8.11307%	14-Dec-98
[illegible]c-98	143,500,000.00	0.00	143,500,000.00	21,648.77	416.67	0.00	22,065.44	5.61246%	8.00000%	31,452.05	416.67	31,868.72	8.10598%	15-Dec-98
[illegible]-98	143,000,000.00	0.00	143,000,000.00	21,077.21	441.33	0.00	21,518.54	5.49249%	8.00000%	31,342.47	441.33	31,783.79	8.11265%	16-Dec-98
17-Dec-98	142,200,000.00	0.00	142,200,000.00	21,055.71	441.33	0.00	21,497.04	5.51788%	7.75000%	30,193.15	441.33	30,634.48	7.86328%	17-Dec-98
18-Dec-98	145,700,000.00	0.00	145,700,000.00	21,751.31	441.33	0.00	22,192.64	5.55958%	7.75000%	30,936.30	441.33	31,377.63	7.86056%	18-Dec-98
19-Dec-98	145,700,000.00	0.00	145,700,000.00	21,751.30	441.33	0.00	22,192.63	5.55958%	7.75000%	30,936.30	441.33	31,377.63	7.86056%	19-Dec-98
20-Dec-98	145,700,000.00	0.00	145,700,000.00	21,751.30	441.33	0.00	22,192.63	5.55958%	7.75000%	30,936.30	441.33	31,377.63	7.86056%	20-Dec-98
21-Dec-98	149,100,000.00	4,000,000.00	145,100,000.00	23,459.77	424.66	563.33	23,321.10	5.86644%	7.75000%	30,808.90	424.66	31,233.56	7.85682%	21-Dec-98
22-Dec-98	147,308,000.00	0.00	147,308,000.00	23,755.95	424.66	0.00	24,180.61	5.99148%	7.75000%	31,277.73	424.66	31,702.39	7.85522%	22-Dec-98
23-Dec-98	142,308,000.00	0.00	142,308,000.00	24,019.85	424.66	0.00	24,444.51	6.26967%	7.75000%	30,216.08	424.66	30,640.74	7.85892%	23-Dec-98
24-Dec-98	142,308,000.00	0.00	142,308,000.00	24,019.85	424.66	0.00	24,444.51	6.26967%	7.75000%	30,216.08	424.66	30,640.74	7.85892%	24-Dec-98
25-Dec-98	142,308,000.00	0.00	142,308,000.00	24,019.85	424.66	0.00	24,444.51	6.26967%	7.75000%	30,216.08	424.66	30,640.74	7.85892%	25-Dec-98
26-Dec-98	142,308,000.00	0.00	142,308,000.00	24,019.85	424.66	0.00	24,444.51	6.26967%	7.75000%	30,216.08	424.66	30,640.74	7.85892%	26-Dec-98
27-Dec-98	142,308,000.00	0.00	142,308,000.00	24,019.85	424.66	0.00	24,444.51	6.26967%	7.75000%	30,216.08	424.66	30,640.74	7.85892%	27-Dec-98
28-Dec-98	157,508,000.00	0.00	157,508,000.00	26,189.74	400.00	0.00	26,589.74	6.16175%	7.75000%	33,443.48	400.00	33,843.48	7.84269%	28-Dec-98
29-Dec-98	156,054,000.00	0.00	156,054,000.00	26,061.33	408.01	0.00	26,469.34	6.19100%	7.75000%	33,134.75	408.01	33,542.76	7.84543%	29-Dec-98
30-Dec-98	162,154,000.00	0.00	162,154,000.00	26,817.97	424.66	0.00	27,242.63	6.13217%	7.75000%	34,429.96	424.66	34,854.62	7.84559%	30-Dec-98
31-Dec-98	168,154,000.00	3,000,000.00	165,154,000.00	27,997.89	400.00	423.33	27,974.56	6.18254%	7.75000%	35,066.95	400.00	35,466.95	7.83840%	31-Dec-98
				673,716.55	13,208.64	1,956.50	684,968.69			946,657.38	13,208.64	959,866.03		

168,154,000.00		162,154,000.00	Maximum Outstanding During Month		
129,930,000.00		129,930,000.00	Minimum Outstanding During Month		
142,017,032.26	448,387.10	135,241,096.77	Month-to-Date Average Outstanding	92,025,806.45	
		684,968.69	Net Month-to-Date Interest Expense/(Income)	959,866.03	
5.6951%	-5.1376%	5.9196%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	12.2810%	(5)
5.5856%		5.8055%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

Most Current Date to Appear on Report: 12/31/98 36160

TO: GARY M. JENKINS
FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Jan-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Jan-99	168,154,000.00	3,000,000.00	165,154,000.00	27,997.89	400.00	423.33	27,974.56	6.18254%	8.00000%	36,198.14	400.00	36,598.14	8.08840%	01-Jan-99
02-Jan-99	168,154,000.00	3,000,000.00	165,154,000.00	27,997.89	400.00	423.33	27,974.56	6.18254%	8.00000%	36,198.14	400.00	36,598.14	8.08840%	02-Jan-99
03-Jan-99	168,154,000.00	3,000,000.00	165,154,000.00	27,997.89	400.00	423.33	27,974.56	6.18254%	8.00000%	36,198.14	400.00	36,598.14	8.08840%	03-Jan-99
04-Jan-99	161,654,000.00	0.00	161,654,000.00	25,530.37	400.00	0.00	25,930.37	5.85484%	8.00000%	35,431.01	400.00	35,831.01	8.09032%	04-Jan-99
05-Jan-99	157,554,000.00	0.00	157,554,000.00	24,644.09	424.66	0.00	25,068.75	5.80759%	8.00000%	34,532.38	424.66	34,957.04	8.09838%	05-Jan-99
06-Jan-99	154,454,000.00	0.00	154,454,000.00	23,720.06	424.66	0.00	24,144.72	5.70579%	8.00000%	33,852.93	424.66	34,277.59	8.10035%	06-Jan-99
07-Jan-99	153,054,000.00	0.00	153,054,000.00	23,399.21	414.18	0.00	23,813.39	5.67897%	8.00000%	33,546.08	414.18	33,960.26	8.09877%	07-Jan-99
08-Jan-99	155,554,000.00	0.00	155,554,000.00	23,383.01	420.34	0.00	23,803.35	5.58534%	8.00000%	34,094.03	420.34	34,514.37	8.09863%	08-Jan-99
09-Jan-99	155,554,000.00	0.00	155,554,000.00	23,383.01	420.34	0.00	23,803.35	5.58534%	8.00000%	34,094.03	420.34	34,514.37	8.09863%	09-Jan-99
10-Jan-99	155,554,000.00	0.00	155,554,000.00	23,383.01	420.34	0.00	23,803.35	5.58534%	8.00000%	34,094.03	420.34	34,514.37	8.09863%	10-Jan-99
11-Jan-99	153,454,000.00	0.00	153,454,000.00	23,099.37	424.66	0.00	23,524.03	5.59534%	8.00000%	33,633.75	424.66	34,058.41	8.10101%	11-Jan-99
12-Jan-99	148,754,000.00	0.00	148,754,000.00	22,228.59	424.66	0.00	22,653.25	5.55846%	8.00000%	32,603.62	424.66	33,028.28	8.10420%	12-Jan-99
13-Jan-99	144,008,000.00	0.00	144,008,000.00	21,438.04	424.66	0.00	21,862.70	5.54128%	8.00000%	31,563.40	424.66	31,988.06	8.10763%	13-Jan-99
14-Jan-99	147,308,000.00	0.00	147,308,000.00	21,911.78	424.66	0.00	22,336.44	5.53453%	8.00000%	32,286.68	424.66	32,711.34	8.10522%	14-Jan-99
[illegible]n-99	155,808,000.00	0.00	155,808,000.00	22,464.97	424.66	0.00	22,889.63	5.36219%	8.00000%	34,149.70	424.66	34,574.36	8.09948%	15-Jan-99
[illegible]n-99	155,808,000.00	0.00	155,808,000.00	22,464.97	424.66	0.00	22,889.63	5.36219%	8.00000%	34,149.70	424.66	34,574.36	8.09948%	16-Jan-99
17-Jan-99	155,808,000.00	0.00	155,808,000.00	22,464.97	424.66	0.00	22,889.63	5.36219%	7.75000%	33,082.52	424.66	33,507.18	7.84948%	17-Jan-99
18-Jan-99	155,808,000.00	0.00	155,808,000.00	22,464.97	424.66	0.00	22,889.63	5.36219%	7.75000%	33,082.52	424.66	33,507.18	7.84948%	18-Jan-99
19-Jan-99	158,208,000.00	0.00	158,208,000.00	22,666.08	424.66	0.00	23,090.74	5.32724%	7.75000%	33,592.11	424.66	34,016.77	7.84797%	19-Jan-99
20-Jan-99	153,400,000.00	0.00	153,400,000.00	21,830.83	424.66	0.00	22,255.49	5.29547%	7.75000%	32,571.23	424.66	32,995.89	7.85104%	20-Jan-99
21-Jan-99	151,100,000.00	0.00	151,100,000.00	21,320.41	441.33	0.00	21,761.74	5.25681%	7.75000%	32,082.88	441.33	32,524.20	7.85661%	21-Jan-99
22-Jan-99	149,700,000.00	0.00	149,700,000.00	20,968.48	416.67	0.00	21,385.15	5.21415%	7.75000%	31,785.62	416.67	32,202.28	7.85159%	22-Jan-99
23-Jan-99	149,700,000.00	0.00	149,700,000.00	20,968.48	416.67	0.00	21,385.15	5.21415%	7.75000%	31,785.62	416.67	32,202.28	7.85159%	23-Jan-99
24-Jan-99	149,700,000.00	0.00	149,700,000.00	20,968.48	416.67	0.00	21,385.15	5.21415%	7.75000%	31,785.62	416.67	32,202.28	7.85159%	24-Jan-99
25-Jan-99	168,400,000.00	0.00	168,400,000.00	23,867.22	416.67	0.00	24,283.89	5.26343%	7.75000%	35,756.16	416.67	36,172.83	7.84031%	25-Jan-99
26-Jan-99	166,900,000.00	0.00	166,900,000.00	24,006.49	441.33	0.00	24,447.82	5.34659%	7.75000%	35,437.67	441.33	35,879.00	7.84652%	26-Jan-99
27-Jan-99	162,700,000.00	0.00	162,700,000.00	23,321.16	441.33	0.00	23,762.49	5.33086%	7.75000%	34,545.89	441.33	34,987.22	7.84901%	27-Jan-99
28-Jan-99	160,000,000.00	0.00	160,000,000.00	17,029.79	416.67	0.00	17,446.46	3.97997%	7.75000%	33,972.60	416.67	34,389.27	7.84505%	28-Jan-99
29-Jan-99	159,800,000.00	0.00	159,800,000.00	16,966.19	416.67	0.00	17,382.86	3.97043%	7.75000%	33,930.14	416.67	34,346.80	7.84517%	29-Jan-99
30-Jan-99	159,800,000.00	0.00	159,800,000.00	16,966.19	416.67	0.00	17,382.86	3.97043%	7.75000%	33,930.14	416.67	34,346.80	7.84517%	30-Jan-99
31-Jan-99	159,800,000.00	0.00	159,800,000.00	16,966.25	416.67	0.00	17,382.92	3.97044%	7.75000%	33,930.14	416.67	34,346.80	7.84517%	31-Jan-99
				697,820.14	13,028.43	1,270.00	709,578.57			1,047,896.60	13,028.43	1,060,925.04		

168,400,000.00		168,400,000.00	Maximum Outstanding During Month		
144,008,000.00		144,008,000.00	Minimum Outstanding During Month		
156,896,903.23	290,322.58	151,451,741.94	Month-to-Date Average Oustanding	92,025,806.45	
		709,578.57	Net Month-to-Date Interest Expense/(Income)	1,060,925.04	
5.3345%	-5.1506%	5.5164%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	13.5739%	(5)
5.2367%		5.4151%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 28-Feb-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
1-Feb-99	158,500,000.00	0.00	158,500,000.00	22,362.92	441.33	0.00	22,804.25	5.25145%	8.00000%	34,739.73	441.33	35,181.05	8.10163%	01-Feb-99
02-Feb-99	156,200,000.00	0.00	156,200,000.00	21,909.39	441.33	0.00	22,350.72	5.22280%	8.00000%	34,235.62	441.33	34,676.94	8.10313%	02-Feb-99
03-Feb-99	151,400,000.00	0.00	151,400,000.00	21,103.88	441.33	0.00	21,545.21	5.19419%	8.00000%	33,183.56	441.33	33,624.89	8.10640%	03-Feb-99
04-Feb-99	149,300,000.00	0.00	149,300,000.00	20,648.13	416.67	0.00	21,064.80	5.14980%	8.00000%	32,723.29	416.67	33,139.95	8.10186%	04-Feb-99
05-Feb-99	144,200,000.00	0.00	144,200,000.00	19,843.67	441.33	0.00	20,285.00	5.13455%	8.00000%	31,605.48	441.33	32,046.81	8.11171%	05-Feb-99
06-Feb-99	144,200,000.00	0.00	144,200,000.00	19,843.67	441.33	0.00	20,285.00	5.13455%	8.00000%	31,605.48	441.33	32,046.81	8.11171%	06-Feb-99
07-Feb-99	144,200,000.00	0.00	144,200,000.00	19,843.67	441.33	0.00	20,285.00	5.13455%	8.00000%	31,605.48	441.33	32,046.81	8.11171%	07-Feb-99
08-Feb-99	141,200,000.00	0.00	141,200,000.00	19,703.33	441.33	0.00	20,144.66	5.20737%	8.00000%	30,947.95	441.33	31,389.27	8.11408%	08-Feb-99
09-Feb-99	135,200,000.00	0.00	135,200,000.00	18,852.94	441.33	0.00	19,294.27	5.20888%	8.00000%	29,632.88	441.33	30,074.20	8.11915%	09-Feb-99
10-Feb-99	129,300,000.00	0.00	129,300,000.00	18,132.75	441.33	0.00	18,574.08	5.24326%	8.00000%	28,339.73	441.33	28,781.05	8.12458%	10-Feb-99
11-Feb-99	125,200,000.00	0.00	125,200,000.00	17,478.14	416.67	0.00	17,894.81	5.21694%	8.00000%	27,441.10	416.67	27,857.76	8.12147%	11-Feb-99
12-Feb-99	124,600,000.00	0.00	124,600,000.00	17,329.42	416.67	0.00	17,746.09	5.19849%	8.00000%	27,309.59	416.67	27,726.26	8.12206%	12-Feb-99
13-Feb-99	124,600,000.00	0.00	124,600,000.00	17,329.42	416.67	0.00	17,746.09	5.19849%	8.00000%	27,309.59	416.67	27,726.26	8.12206%	13-Feb-99
14-Feb-99	124,600,000.00	0.00	124,600,000.00	17,329.42	416.67	0.00	17,746.09	5.19849%	8.00000%	27,309.59	416.67	27,726.26	8.12206%	14-Feb-99
[illegible]b-99	124,600,000.00	0.00	124,600,000.00	17,329.42	416.67	0.00	17,746.09	5.19849%	8.00000%	27,309.59	416.67	27,726.26	8.12206%	15-Feb-99
[illegible]b-99	124,000,000.00	0.00	124,000,000.00	17,519.40	416.67	0.00	17,936.07	5.27957%	8.00000%	27,178.08	416.67	27,594.75	8.12265%	16-Feb-99
17-Feb-99	118,800,000.00	0.00	118,800,000.00	16,735.93	427.35	0.00	17,163.28	5.27323%	8.00000%	26,038.36	427.35	26,465.70	8.13130%	17-Feb-99
18-Feb-99	118,200,000.00	0.00	118,200,000.00	16,484.44	428.59	0.00	16,913.03	5.22272%	8.00000%	25,906.85	428.59	26,335.44	8.13235%	18-Feb-99
19-Feb-99	115,900,000.00	0.00	115,900,000.00	16,122.50	441.33	0.00	16,563.83	5.21639%	8.00000%	25,402.74	441.33	25,844.07	8.13899%	19-Feb-99
20-Feb-99	115,900,000.00	0.00	115,900,000.00	16,122.50	441.33	0.00	16,563.83	5.21639%	8.00000%	25,402.74	441.33	25,844.07	8.13899%	20-Feb-99
21-Feb-99	115,900,000.00	0.00	115,900,000.00	16,122.50	441.33	0.00	16,563.83	5.21639%	8.00000%	25,402.74	441.33	25,844.07	8.13899%	21-Feb-99
22-Feb-99	112,500,000.00	0.00	112,500,000.00	15,761.80	441.33	0.00	16,203.13	5.25701%	8.00000%	24,657.53	441.33	25,098.86	8.14319%	22-Feb-99
23-Feb-99	108,000,000.00	0.00	108,000,000.00	15,124.44	441.33	0.00	15,565.77	5.26065%	8.00000%	23,671.23	441.33	24,112.56	8.14915%	23-Feb-99
24-Feb-99	113,800,000.00	0.00	113,800,000.00	15,950.39	441.33	0.00	16,391.72	5.25745%	8.00000%	24,942.47	441.33	25,383.79	8.14155%	24-Feb-99
25-Feb-99	124,900,000.00	0.00	124,900,000.00	17,504.53	418.52	0.00	17,923.05	5.23772%	8.00000%	27,375.34	418.52	27,793.86	8.12230%	25-Feb-99
26-Feb-99	126,100,000.00	0.00	126,100,000.00	17,767.82	416.67	0.00	18,184.49	5.26355%	8.00000%	27,638.36	416.67	28,055.02	8.12061%	26-Feb-99
27-Feb-99	126,100,000.00	0.00	126,100,000.00	17,767.82	416.67	0.00	18,184.49	5.26355%	8.00000%	27,638.36	416.67	28,055.02	8.12061%	27-Feb-99
28-Feb-99	126,100,000.00	0.00	126,100,000.00	17,767.82	416.67	0.00	18,184.49	5.26355%	8.00000%	27,638.36	416.67	28,055.02	8.12061%	28-Feb-99
				505,792.06	12,061.02	0.00	517,853.08			794,191.78	12,061.02	806,252.80		

158,500,000.00		158,500,000.00	Maximum Outstanding During Month	
108,000,000.00		108,000,000.00	Minimum Outstanding During Month	
129,410,714.29	0.00	129,410,714.29	Month-to-Date Average Oustanding	101,885,714.29
		517,853.08	Net Month-to-Date Interest Expense/(Income)	806,252.80
5.2164%	N.A.	5.2164%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	10.3156% (5)
5.0949%		5.0949%	Above Rates Net of Commitment Fees	

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.
(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.
(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.
(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.
(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-Mar-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
1-Mar-99	126,900,000.00	0.00	126,900,000.00	17,922.92	416.67	0.00	18,339.59	5.27498%	8.00000%	27,813.70	416.67	28,230.37	8.11985%	01-Mar-99
02-Mar-99	130,200,000.00	0.00	130,200,000.00	18,404.69	416.67	0.00	18,821.36	5.27634%	8.00000%	28,536.99	416.67	28,953.65	8.11681%	02-Mar-99
03-Mar-99	126,500,000.00	0.00	126,500,000.00	17,773.42	416.67	0.00	18,190.09	5.24852%	8.00000%	27,726.03	416.67	28,142.69	8.12022%	03-Mar-99
04-Mar-99	122,300,000.00	0.00	122,300,000.00	17,135.82	416.67	0.00	17,552.49	5.23848%	8.00000%	26,805.48	416.67	27,222.15	8.12435%	04-Mar-99
05-Mar-99	121,300,000.00	0.00	121,300,000.00	16,983.82	418.11	0.00	17,401.93	5.23636%	8.00000%	26,586.30	418.11	27,004.41	8.12581%	05-Mar-99
06-Mar-99	121,300,000.00	0.00	121,300,000.00	16,983.82	418.11	0.00	17,401.93	5.23636%	8.00000%	26,586.30	418.11	27,004.41	8.12581%	06-Mar-99
07-Mar-99	121,300,000.00	0.00	121,300,000.00	16,983.82	418.11	0.00	17,401.93	5.23636%	8.00000%	26,586.30	418.11	27,004.41	8.12581%	07-Mar-99
08-Mar-99	117,900,000.00	0.00	117,900,000.00	16,528.08	441.33	0.00	16,969.41	5.25346%	8.00000%	25,841.10	441.33	26,282.42	8.13663%	08-Mar-99
09-Mar-99	123,400,000.00	0.00	123,400,000.00	17,325.06	441.33	0.00	17,766.39	5.25505%	8.00000%	27,046.58	441.33	27,487.90	8.13054%	09-Mar-99
10-Mar-99	120,500,000.00	0.00	120,500,000.00	16,931.41	419.75	0.00	17,351.16	5.25574%	8.00000%	26,410.96	419.75	26,830.71	8.12714%	10-Mar-99
11-Mar-99	115,600,000.00	0.00	115,600,000.00	16,285.55	416.67	0.00	16,702.22	5.27362%	8.00000%	25,336.99	416.67	25,753.65	8.13156%	11-Mar-99
12-Mar-99	112,500,000.00	0.00	112,500,000.00	15,805.10	416.67	0.00	16,221.77	5.26306%	8.00000%	24,657.53	416.67	25,074.20	8.13519%	12-Mar-99
13-Mar-99	112,500,000.00	0.00	112,500,000.00	15,805.10	416.67	0.00	16,221.77	5.26306%	8.00000%	24,657.53	416.67	25,074.20	8.13519%	13-Mar-99
14-Mar-99	112,500,000.00	0.00	112,500,000.00	15,805.10	416.67	0.00	16,221.77	5.26306%	8.00000%	24,657.53	416.67	25,074.20	8.13519%	14-Mar-99
[illegible]r-99	111,400,000.00	0.00	111,400,000.00	15,642.53	417.90	0.00	16,060.43	5.26217%	8.00000%	24,416.44	417.90	24,834.34	8.13692%	15-Mar-99
[illegible]ar-99	113,800,000.00	0.00	113,800,000.00	15,980.95	441.33	0.00	16,422.28	5.26725%	8.00000%	24,942.47	441.33	25,383.79	8.14155%	16-Mar-99
17-Mar-99	110,600,000.00	0.00	110,600,000.00	15,533.84	441.33	0.00	15,975.17	5.27209%	8.00000%	24,241.10	441.33	24,682.42	8.14565%	17-Mar-99
18-Mar-99	108,500,000.00	0.00	108,500,000.00	15,214.83	423.86	0.00	15,638.69	5.26094%	8.00000%	23,780.82	423.86	24,204.68	8.14259%	18-Mar-99
19-Mar-99	107,300,000.00	0.00	107,300,000.00	15,050.78	426.33	0.00	15,477.11	5.26481%	8.00000%	23,517.81	426.33	23,944.13	8.14502%	19-Mar-99
20-Mar-99	107,300,000.00	0.00	107,300,000.00	15,050.78	426.33	0.00	15,477.11	5.26481%	8.00000%	23,517.81	426.33	23,944.13	8.14502%	20-Mar-99
21-Mar-99	107,300,000.00	0.00	107,300,000.00	15,050.78	426.33	0.00	15,477.11	5.26481%	8.00000%	23,517.81	426.33	23,944.13	8.14502%	21-Mar-99
22-Mar-99	106,500,000.00	0.00	106,500,000.00	14,950.31	427.97	0.00	15,378.28	5.27049%	8.00000%	23,342.47	427.97	23,770.43	8.14667%	22-Mar-99
23-Mar-99	102,800,000.00	0.00	102,800,000.00	14,447.08	435.57	0.00	14,882.65	5.28421%	8.00000%	22,531.51	435.57	22,967.07	8.15465%	23-Mar-99
24-Mar-99	99,900,000.00	0.00	99,900,000.00	14,050.02	420.99	0.00	14,471.01	5.28720%	8.00000%	21,895.89	420.99	22,316.88	8.15381%	24-Mar-99
25-Mar-99	113,000,000.00	0.00	113,000,000.00	15,954.00	435.16	0.00	16,389.16	5.29384%	8.00000%	24,767.12	435.16	25,202.28	8.14056%	25-Mar-99
26-Mar-99	117,000,000.00	0.00	117,000,000.00	16,601.29	426.94	0.00	17,028.23	5.31222%	8.00000%	25,643.84	426.94	26,070.77	8.13319%	26-Mar-99
27-Mar-99	117,000,000.00	0.00	117,000,000.00	16,601.29	426.94	0.00	17,028.23	5.31222%	8.00000%	25,643.84	426.94	26,070.77	8.13319%	27-Mar-99
28-Mar-99	117,000,000.00	0.00	117,000,000.00	16,601.29	426.94	0.00	17,028.23	5.31222%	8.00000%	25,643.84	426.94	26,070.77	8.13319%	28-Mar-99
29-Mar-99	116,400,000.00	0.00	116,400,000.00	16,531.41	416.67	0.00	16,948.08	5.31447%	8.00000%	25,512.33	416.67	25,929.00	8.13066%	29-Mar-99
30-Mar-99	113,400,000.00	0.00	113,400,000.00	16,115.29	416.67	0.00	16,531.96	5.32113%	8.00000%	24,854.79	416.67	25,271.46	8.13411%	30-Mar-99
31-Mar-99	112,300,000.00	3,000,000.00	109,300,000.00	15,938.92	416.67	400.83	15,954.76	5.32798%	8.00000%	23,956.16	416.67	24,372.83	8.13914%	31-Mar-99
				501,989.10	13,143.93	400.83	514,732.20			780,975.34	13,143.93	794,119.27		

130,200,000.00		130,200,000.00	Maximum Outstanding During Month	
99,900,000.00		99,900,000.00	Minimum Outstanding During Month	
115,038,709.68	96,774.19	111,416,129.03	Month-to-Date Average Oustanding	92,025,806.45
		514,732.20	Net Month-to-Date Interest Expense/(Income)	794,119.27
5.2724%	-4.8768%	5.4396%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	10.1603% (5)
5.1379%		5.3007%	Above Rates Net of Commitment Fees	

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.
(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.
(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.
(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.
(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

TO: GARY M. JENKINS
FROM. DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 30-Apr-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Apr-99	103,600,000.00	0.00	103,600,000.00	14,772.19	416.67	0.00	15,188.86	5.35129%	8.00000%	22,706.85	416.67	23,123.52	8.14680%	01-Apr-99
02-Apr-99	101,600,000.00	0.00	101,600,000.00	14,633.00	417.22	0.00	15,050.22	5.40682%	8.00000%	22,268.49	417.22	22,685.71	8.14989%	02-Apr-99
03-Apr-99	101,600,000.00	0.00	101,600,000.00	14,633.00	417.22	0.00	15,050.22	5.40682%	8.00000%	22,268.49	417.22	22,685.71	8.14989%	03-Apr-99
04-Apr-99	101,600,000.00	0.00	101,600,000.00	14,633.00	417.22	0.00	15,050.22	5.40682%	8.00000%	22,268.49	417.22	22,685.71	8.14989%	04-Apr-99
05-Apr-99	101,100,000.00	0.00	101,100,000.00	14,290.78	417.90	0.00	14,708.68	5.31025%	8.00000%	22,158.90	417.90	22,576.80	8.15087%	05-Apr-99
06-Apr-99	95,600,000.00	0.00	95,600,000.00	13,557.38	425.44	0.00	13,982.82	5.33863%	8.00000%	20,953.42	425.44	21,378.86	8.16243%	06-Apr-99
07-Apr-99	91,900,000.00	0.00	91,900,000.00	12,979.89	416.81	0.00	13,396.70	5.32078%	8.00000%	20,142.47	416.81	20,559.27	8.16554%	07-Apr-99
08-Apr-99	91,100,000.00	0.00	91,100,000.00	12,858.77	417.90	0.00	13,276.67	5.31941%	8.00000%	19,967.12	417.90	20,385.02	8.16743%	08-Apr-99
09-Apr-99	90,400,000.00	0.00	90,400,000.00	12,749.67	433.11	0.00	13,182.78	5.32269%	8.00000%	19,813.70	433.11	20,246.81	8.17487%	09-Apr-99
10-Apr-99	90,400,000.00	0.00	90,400,000.00	12,749.67	433.11	0.00	13,182.78	5.32269%	8.00000%	19,813.70	433.11	20,246.81	8.17487%	10-Apr-99
11-Apr-99	90,400,000.00	0.00	90,400,000.00	12,749.67	433.11	0.00	13,182.78	5.32269%	8.00000%	19,813.70	433.11	20,246.81	8.17487%	11-Apr-99
12-Apr-99	88,500,000.00	0.00	88,500,000.00	12,503.89	421.46	0.00	12,925.35	5.33079%	8.00000%	19,397.26	421.46	19,818.72	8.17382%	12-Apr-99
13-Apr-99	86,000,000.00	0.00	86,000,000.00	12,153.89	424.89	0.00	12,578.78	5.33867%	8.00000%	18,849.32	424.89	19,274.20	8.18033%	13-Apr-99
14-Apr-99	84,300,000.00	0.00	84,300,000.00	11,768.63	433.11	0.00	12,201.74	5.28308%	8.00000%	18,476.71	433.11	18,909.82	8.18753%	14-Apr-99
15-Apr-99	82,700,000.00	0.00	82,700,000.00	11,614.77	433.11	0.00	12,047.88	5.31738%	8.00000%	18,126.03	433.11	18,559.13	8.19115%	15-Apr-99
16-Apr-99	80,400,000.00	0.00	80,400,000.00	11,187.76	418.86	0.00	11,606.62	5.26917%	8.00000%	17,621.92	418.86	18,040.77	8.19015%	16-Apr-99
17-Apr-99	80,400,000.00	0.00	80,400,000.00	11,187.76	418.86	0.00	11,606.62	5.26917%	8.00000%	17,621.92	418.86	18,040.77	8.19015%	17-Apr-99
18-Apr-99	80,400,000.00	0.00	80,400,000.00	11,187.76	418.86	0.00	11,606.62	5.26917%	8.00000%	17,621.92	418.86	18,040.77	8.19015%	18-Apr-99
19-Apr-99	81,900,000.00	0.00	81,900,000.00	11,453.92	416.81	0.00	11,870.73	5.29037%	8.00000%	17,950.68	416.81	18,367.49	8.18576%	19-Apr-99
20-Apr-99	80,900,000.00	0.00	80,900,000.00	11,262.91	433.11	0.00	11,696.02	5.27694%	8.00000%	17,731.51	433.11	18,164.61	8.19541%	20-Apr-99
21-Apr-99	77,800,000.00	0.00	77,800,000.00	10,811.66	422.42	0.00	11,234.08	5.27049%	8.00000%	17,052.05	422.42	17,474.47	8.19818%	21-Apr-99
22-Apr-99	75,100,000.00	0.00	75,100,000.00	10,397.29	426.12	0.00	10,823.41	5.26038%	8.00000%	16,460.27	426.12	16,886.39	8.20710%	22-Apr-99
23-Apr-99	85,100,000.00	0.00	85,100,000.00	11,731.53	433.11	0.00	12,164.64	5.21750%	8.00000%	18,652.05	433.11	19,085.16	8.18576%	23-Apr-99
24-Apr-99	85,100,000.00	0.00	85,100,000.00	11,731.53	433.11	0.00	12,164.64	5.21750%	8.00000%	18,652.05	433.11	19,085.16	8.18576%	24-Apr-99
25-Apr-99	85,100,000.00	0.00	85,100,000.00	11,731.53	433.11	0.00	12,164.64	5.21750%	8.00000%	18,652.05	433.11	19,085.16	8.18576%	25-Apr-99
26-Apr-99	91,900,000.00	0.00	91,900,000.00	12,704.52	416.67	0.00	13,121.19	5.21135%	8.00000%	20,142.47	416.67	20,559.13	8.16549%	26-Apr-99
27-Apr-99	89,600,000.00	0.00	89,600,000.00	12,494.31	416.67	0.00	12,910.98	5.25949%	8.00000%	19,638.36	416.67	20,055.02	8.16974%	27-Apr-99
28-Apr-99	87,500,000.00	0.00	87,500,000.00	12,290.28	433.11	0.00	12,723.39	5.30747%	8.00000%	19,178.08	433.11	19,611.19	8.18067%	28-Apr-99
29-Apr-99	87,300,000.00	0.00	87,300,000.00	12,251.80	416.67	0.00	12,668.47	5.29667%	8.00000%	19,134.25	416.67	19,550.91	8.17421%	29-Apr-99
30-Apr-99	95,200,000.00	0.00	95,200,000.00	13,376.53	416.67	0.00	13,793.20	5.28836%	8.00000%	20,865.75	416.67	21,282.42	8.15975%	30-Apr-99
				374,449.29	12,712.34	0.00	387,161.63			584,000.00	12,712.34	596,712.34		

103,600,000.00		103,600,000.00	Maximum Outstanding During Month		
75,100,000.00		75,100,000.00	Minimum Outstanding During Month		
88,816,666.67	0.00	88,816,666.67	Month-to-Date Average Oustanding	95,093,333.33	
		387,161.63	Net Month-to-Date Interest Expense/(Income)	596,712.34	
5.3036%	N.A.	5.3036%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	7.6346%	(5)
5.1294%		5.1294%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

FROM. DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 31-May-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-May-99	115,200,000.00	0.00	115,200,000.00	13,376.53	416.67	0.00	13,793.20	4.37024%	8.00000%	25,249.32	416.67	25,665.98	8.13202%	01-May-99
02-May-99	115,200,000.00	0.00	115,200,000.00	13,376.53	416.67	0.00	13,793.20	4.37024%	8.00000%	25,249.32	416.67	25,665.98	8.13202%	02-May-99
03-May-99	93,100,000.00	0.00	93,100,000.00	13,207.88	416.67	0.00	13,624.55	5.34152%	8.00000%	20,405.48	416.67	20,822.15	8.16335%	03-May-99
04-May-99	89,200,000.00	0.00	89,200,000.00	12,536.67	433.11	0.00	12,969.78	5.30714%	8.00000%	19,550.68	433.11	19,983.79	8.17722%	04-May-99
05-May-99	93,100,000.00	0.00	93,100,000.00	12,958.77	428.86	0.00	13,387.63	5.24864%	8.00000%	20,405.48	428.86	20,834.34	8.16813%	05-May-99
06-May-99	92,500,000.00	0.00	92,500,000.00	12,851.24	416.67	0.00	13,267.91	5.23544%	8.00000%	20,273.97	416.67	20,690.64	8.16441%	06-May-99
07-May-99	97,100,000.00	0.00	97,100,000.00	13,517.02	416.67	0.00	13,933.69	5.23769%	8.00000%	21,282.19	416.67	21,698.86	8.15663%	07-May-99
08-May-99	97,100,000.00	0.00	97,100,000.00	13,517.02	416.67	0.00	13,933.69	5.23769%	8.00000%	21,282.19	416.67	21,698.86	8.15663%	08-May-99
09-May-99	97,100,000.00	0.00	97,100,000.00	13,517.02	416.67	0.00	13,933.69	5.23769%	8.00000%	21,282.19	416.67	21,698.86	8.15663%	09-May-99
10-May-99	94,100,000.00	0.00	94,100,000.00	13,124.73	416.67	0.00	13,541.40	5.25251%	8.00000%	20,624.66	416.67	21,041.32	8.16162%	10-May-99
11-May-99	91,300,000.00	0.00	91,300,000.00	12,709.53	416.67	0.00	13,126.20	5.24760%	8.00000%	20,010.96	416.67	20,427.63	8.16658%	11-May-99
ay-99	88,900,000.00	0.00	88,900,000.00	12,371.47	416.67	0.00	12,788.14	5.25047%	8.00000%	19,484.93	416.67	19,901.60	8.17107%	12-May-99
ay-99	87,400,000.00	0.00	87,400,000.00	12,176.68	416.67	0.00	12,593.35	5.25924%	8.00000%	19,156.16	416.67	19,572.83	8.17401%	13-May-99
14-May-99	92,500,000.00	0.00	92,500,000.00	12,879.39	416.67	0.00	13,296.06	5.24655%	8.00000%	20,273.97	416.67	20,690.64	8.16441%	14-May-99
15-May-99	92,500,000.00	0.00	92,500,000.00	12,879.39	416.67	0.00	13,296.06	5.24655%	8.00000%	20,273.97	416.67	20,690.64	8.16441%	15-May-99
16-May-99	92,500,000.00	0.00	92,500,000.00	12,879.39	416.67	0.00	13,296.06	5.24655%	8.00000%	20,273.97	416.67	20,690.64	8.16441%	16-May-99
17-May-99	92,000,000.00	0.00	92,000,000.00	12,898.42	416.67	0.00	13,315.09	5.28262%	8.00000%	20,164.38	416.67	20,581.05	8.16531%	17-May-99
18-May-99	89,500,000.00	0.00	89,500,000.00	12,500.32	416.67	0.00	12,916.99	5.26782%	8.00000%	19,616.44	416.67	20,033.11	8.16993%	18-May-99
19-May-99	90,000,000.00	0.00	90,000,000.00	12,569.48	416.67	0.00	12,986.15	5.26660%	8.00000%	19,726.03	416.67	20,142.69	8.16898%	19-May-99
20-May-99	91,500,000.00	0.00	91,500,000.00	12,760.73	416.67	0.00	13,177.40	5.25656%	8.00000%	20,054.79	416.67	20,471.46	8.16621%	20-May-99
21-May-99	92,800,000.00	0.00	92,800,000.00	12,974.20	416.67	0.00	13,390.87	5.26688%	8.00000%	20,339.73	416.67	20,756.39	8.16388%	21-May-99
22-May-99	92,800,000.00	0.00	92,800,000.00	12,974.20	416.67	0.00	13,390.87	5.26688%	8.00000%	20,339.73	416.67	20,756.39	8.16388%	22-May-99
23-May-99	92,800,000.00	0.00	92,800,000.00	12,974.20	416.67	0.00	13,390.87	5.26688%	8.00000%	20,339.73	416.67	20,756.39	8.16388%	23-May-99
24-May-99	92,200,000.00	0.00	92,200,000.00	12,902.80	416.67	0.00	13,319.47	5.27289%	8.00000%	20,208.22	416.67	20,624.89	8.16495%	24-May-99
25-May-99	92,800,000.00	0.00	92,800,000.00	12,981.15	416.67	0.00	13,397.82	5.26962%	8.00000%	20,339.73	416.67	20,756.39	8.16388%	25-May-99
26-May-99	100,600,000.00	0.00	100,600,000.00	14,159.50	416.67	0.00	14,576.17	5.28857%	8.00000%	22,049.32	416.67	22,465.98	8.15118%	26-May-99
27-May-99	101,553,000.00	0.00	101,553,000.00	14,245.20	416.67	0.00	14,661.87	5.26974%	8.00000%	22,258.19	416.67	22,674.86	8.14976%	27-May-99
28-May-99	98,900,000.00	0.00	98,900,000.00	13,895.76	416.67	0.00	14,312.43	5.28214%	8.00000%	21,676.71	416.67	22,093.38	8.15377%	28-May-99
29-May-99	98,900,000.00	0.00	98,900,000.00	13,895.76	416.67	0.00	14,312.43	5.28214%	8.00000%	21,676.71	416.67	22,093.38	8.15377%	29-May-99
30-May-99	98,900,000.00	0.00	98,900,000.00	13,895.76	416.67	0.00	14,312.43	5.28214%	8.00000%	21,676.71	416.67	22,093.38	8.15377%	30-May-99
31-May-99	98,900,000.00	0.00	98,900,000.00	13,895.76	416.67	0.00	14,312.43	5.28214%	8.00000%	21,676.71	416.67	22,093.38	8.15377%	31-May-99
				407,402.50	12,945.30	0.00	420,347.80			647,222.58	12,945.30	660,167.87		

115,200,000.00		115,200,000.00	Maximum Outstanding During Month		
87,400,000.00		87,400,000.00	Minimum Outstanding During Month		
95,256,548.39	0.00	92,066,225.81	Month-to-Date Average Oustanding	92,025,806.45	
		420,347.80	Net Month-to-Date Interest Expense/(Income)	660,167.87	
5.1957%	N.A.	5.3758%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	8.4465%	(5)
5.0357%		5.2102%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

FROM: DARLA D. CARVER

SUBJ: WEIGHTED AVERAGE COST OF SHORT TERM DEBT
DATE: 30-Jun-99

Date	Short Term Debt Outstanding	Short Term Investments Outstanding	Net S. T. Debt/(Invest) Outstanding	Interest Expense	Commitment Fees	Interest Income	Net Expense/ (Income)	Eff. Rate of S.T. Debt/(-) R.O.Invest(1)	NationsBank Prime Rate	Interest Expense (2)	Commitment Fees	Net Interest Expense	Comparative Eff. Rate of S/T Debt @ NBANK Prime	Date
01-Jun-99	98,250,000.00	0.00	98,250,000.00	13,780.07	416.67	0.00	14,196.74	5.27411%	8.00000%	21,534.25	416.67	21,950.91	8.15479%	01-Jun-99
02-Jun-99	96,050,000.00	0.00	96,050,000.00	13,452.65	416.67	0.00	13,869.32	5.27048%	8.00000%	21,052.05	416.67	21,468.72	8.15834%	02-Jun-99
03-Jun-99	95,000,000.00	0.00	95,000,000.00	13,268.23	416.67	0.00	13,684.90	5.25788%	8.00000%	20,821.92	416.67	21,238.58	8.16009%	03-Jun-99
04-Jun-99	96,200,000.00	0.00	96,200,000.00	13,464.60	416.67	0.00	13,881.27	5.26680%	8.00000%	21,084.93	416.67	21,501.60	8.15809%	04-Jun-99
05-Jun-99	96,200,000.00	0.00	96,200,000.00	13,464.60	416.67	0.00	13,881.27	5.26680%	8.00000%	21,084.93	416.67	21,501.60	8.15809%	05-Jun-99
06-Jun-99	96,200,000.00	0.00	96,200,000.00	13,464.60	416.67	0.00	13,881.27	5.26680%	8.00000%	21,084.93	416.67	21,501.60	8.15809%	06-Jun-99
07-Jun-99	96,900,000.00	0.00	96,900,000.00	13,570.06	416.67	0.00	13,986.73	5.26848%	8.00000%	21,238.36	416.67	21,655.02	8.15695%	07-Jun-99
08-Jun-99	98,600,000.00	0.00	98,600,000.00	13,788.64	416.67	0.00	14,205.31	5.25856%	8.00000%	21,610.96	416.67	22,027.63	8.15424%	08-Jun-99
09-Jun-99	99,900,000.00	0.00	99,900,000.00	13,800.24	416.67	0.00	14,216.91	5.19437%	8.00000%	21,895.89	416.67	22,312.56	8.15224%	09-Jun-99
10-Jun-99	106,700,000.00	0.00	106,700,000.00	14,959.57	416.67	0.00	15,376.24	5.25991%	8.00000%	23,386.30	416.67	23,802.97	8.14253%	10-Jun-99
11-Jun-99	100,700,000.00	0.00	100,700,000.00	14,115.07	416.67	0.00	14,531.74	5.26721%	8.00000%	22,071.23	416.67	22,487.90	8.15103%	11-Jun-99
[illegible]-Jun-99	100,700,000.00	0.00	100,700,000.00	14,115.07	416.67	0.00	14,531.74	5.26721%	8.00000%	22,071.23	416.67	22,487.90	8.15103%	12-Jun-99
[illegible]-Jun-99	100,700,000.00	0.00	100,700,000.00	14,115.07	416.67	0.00	14,531.74	5.26721%	8.00000%	22,071.23	416.67	22,487.90	8.15103%	13-Jun-99
14-Jun-99	96,100,000.00	0.00	96,100,000.00	13,507.69	417.90	0.00	13,925.59	5.28911%	8.00000%	21,063.01	417.90	21,480.91	8.15872%	14-Jun-99
15-Jun-99	94,100,000.00	0.00	94,100,000.00	13,205.06	420.64	0.00	13,625.70	5.28521%	8.00000%	20,624.66	420.64	21,045.29	8.16316%	15-Jun-99
16-Jun-99	97,641,000.00	0.00	97,641,000.00	13,656.27	433.11	0.00	14,089.38	5.26687%	8.00000%	21,400.77	433.11	21,833.87	8.16190%	16-Jun-99
17-Jun-99	99,920,000.00	0.00	99,920,000.00	13,946.03	433.11	0.00	14,379.14	5.25259%	8.00000%	21,900.27	433.11	22,333.38	8.15821%	17-Jun-99
18-Jun-99	100,760,000.00	0.00	100,760,000.00	14,060.60	433.11	0.00	14,493.71	5.25030%	8.00000%	22,084.38	433.11	22,517.49	8.15689%	18-Jun-99
19-Jun-99	100,760,000.00	0.00	100,760,000.00	14,060.60	433.11	0.00	14,493.71	5.25030%	8.00000%	22,084.38	433.11	22,517.49	8.15689%	19-Jun-99
20-Jun-99	100,760,000.00	0.00	100,760,000.00	14,060.60	433.11	0.00	14,493.71	5.25030%	8.00000%	22,084.38	433.11	22,517.49	8.15689%	20-Jun-99
21-Jun-99	100,300,000.00	0.00	100,300,000.00	14,023.36	433.11	0.00	14,456.47	5.26083%	8.00000%	21,983.56	433.11	22,416.67	8.15761%	21-Jun-99
22-Jun-99	99,300,000.00	0.00	99,300,000.00	13,885.30	433.11	0.00	14,318.41	5.26306%	8.00000%	21,764.38	433.11	22,197.49	8.15920%	22-Jun-99
23-Jun-99	99,300,000.00	0.00	99,300,000.00	14,151.75	433.11	0.00	14,584.86	5.36100%	8.00000%	21,764.38	433.11	22,197.49	8.15920%	23-Jun-99
24-Jun-99	98,300,000.00	0.00	98,300,000.00	14,506.97	433.11	0.00	14,940.08	5.54743%	8.00000%	21,545.21	433.11	21,978.31	8.16082%	24-Jun-99
25-Jun-99	109,200,000.00	0.00	109,200,000.00	16,068.91	418.18	0.00	16,487.09	5.51079%	8.00000%	23,934.25	418.18	24,352.42	8.13978%	25-Jun-99
26-Jun-99	109,200,000.00	0.00	109,200,000.00	16,068.91	418.18	0.00	16,487.09	5.51079%	8.00000%	23,934.25	418.18	24,352.42	8.13978%	26-Jun-99
27-Jun-99	109,200,000.00	0.00	109,200,000.00	16,068.91	418.18	0.00	16,487.09	5.51079%	8.00000%	23,934.25	418.18	24,352.42	8.13978%	27-Jun-99
28-Jun-99	109,400,000.00	0.00	109,400,000.00	16,128.03	417.90	0.00	16,545.93	5.52035%	8.00000%	23,978.08	417.90	24,395.98	8.13943%	28-Jun-99
29-Jun-99	106,900,000.00	0.00	106,900,000.00	15,804.42	417.90	0.00	16,222.32	5.53896%	8.00000%	23,430.14	417.90	23,848.03	8.14269%	29-Jun-99
30-Jun-99	110,400,000.00	0.00	110,400,000.00	16,472.69	417.90	0.00	16,890.59	5.58430%	8.00000%	24,197.26	417.90	24,615.16	8.13816%	30-Jun-99
				429,034.57	12,661.38	0.00	441,695.95			662,715.84	12,661.38	675,377.22		

Short Term Debt	Short Term Investments	Net S. T. Debt/(Invest)	Description	Net Interest Expense	
110,400,000.00		110,400,000.00	Maximum Outstanding During Month		
0.00		94,100,000.00	Minimum Outstanding During Month		
100,788,033.33	0.00	100,788,033.33	Month-to-Date Average Oustanding	95,093,333.33	
		441,695.95	Net Month-to-Date Interest Expense/(Income)	675,377.22	
5.3319%	N.A.	5.3319%	Month-to-Date Average Effective Rate of Short Term Debt/(-)Return on Investment (3) & (4)	8.6411%	(5)
5.1791%		5.1791%	Above Rates Net of Commitment Fees		

(1) The Effective Rate of Short Term Debt/(-)Return on Investments is Computed by Dividing the Net Interest Expense/(Income) by Net Short Term Debt/(Investment) Oustanding Multiplied By 365 Days.

(2) Short Term Debt Outstanding Times the NationsBank Prime Rate Divided by 365 Days.

(3) The Average Effective Rate of Net Short Term Debt is Computed by Dividing the Total Net Interest Expense by the Average Expense by the Average Net Short Term Debt Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(4) The Average Effective Rate on Net Investments is Computed by Dividing the Net Interest (Income) by the Average Net Short Term Investment Outstanding Multiplied by 365 Days Divided by the Number of Days Elapsed Within the Month.

(5) The Average Effective Rate of Borrowing on a Daily Basis at NationsBank Prime Rate is Computed by Dividing the Total Net Interest Expense by the Daily Average Net Debt Position Multiplied by 365 Divided by The Actual Number of Days Elapsed in the Month; If There is Net Income, This Computation is Not Applicable.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 2
Witness: John P. Reddy

Data Request:

2. Provide the average daily interest amount charged on the average daily amount of outstanding short-term debt for the fiscal years 1995, 1996, 1997, 1998, and 1999.

Response:

Please see attached work sheets for AG DR Item 1 for average daily interest on short-term debt for fiscal years 1995 through June 30, 1999. [Note: Daily short-term interest amounts do not include United Cities Gas Company short-term debt interest prior to September 1997 when UCG was acquired by Atmos.]

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 3
Witness: Donald A. Murry

Data Request:

Refer to page 2 , lines 9-11 of your pre-filed testimony. You state that you were Vice-president and Corporate Economist and manager of the Washington office for Stone & Webster from 1978 to early 1981. On page 1, lines 12 & 13, you state that you have been a Professor of Economics at the University of Oklahoma from 1974 to present. Please explain the apparent conflict in the overlapping years.

Response:

Since Dr. Murry was on leave of absence from a tenured professorship at the University of Oklahoma during 1978-81 while he served with Stone & Webster, there is no conflict in the two statements on page 2.

Data Request:

Refer to page 1, lines 11 and 12. You state that you were on the faculty of the University of Missouri-St. Louis from 1964-74. On page 2, lines 8 and 9 you indicate that you were with the FPC in 1971-72. Please explain the overlap in years in 1971-72.

Response:

Since Dr. Murry was on leave of absence from a tenured professorship at the University of Missouri-St. Louis during 1971-72 while he served with the Federal Power Commission, there is no conflict in the two statements on page 1.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 5
Witness: Donald A. Murry

Data Request:

Please provide a listing of docket numbers or case numbers for every proceeding in which you have appeared or filed testimony since January 1, 1995.

Response:

Please see attached.

PRINT

Name of Utility or Intervenor	Regulatory Agency	Docket No.	Date Filed
United Cities Gas Co.	Kansas C.C.	95-UNCG-364-RTS	01-95
United Cities Gas Co.	Missouri P.S.C.	GR-95-160	01-95
United Cities Gas Co.	Kansas C.C.	95-UNCG-364-RTS	07-95
United Cities Gas Co.	Virginia C.C.	PUE950008	04-95
Empire District Electric Co.	Missouri P.S.C.	ER95-279	05-95
United Cities Gas Co.	Tennessee P.S.C.	95-02258	05-95
Piedmont Natural Gas Co.	S. Carolina P.S.C.	95-715-G	09-95
United Cities Gas Co. Div. Atmos	Tennessee P.S.C.	95-02258	10-95
Piedmont Natural Gas Co.	S. Carolina P.S.C.	95-715-G	10-95
United Cities Gas Co.	Iowa D.C.	RPU-95-14	11-95
Golden Spread Elec. Coop	Texas P.U.C.	15100	12-95
Indian Nations, et al	US Dist W Oklahoma	CIV-92-1987-M	12-95
Laclede Gas Co.	Missouri P.S.C.	GR-96-193	02-96
Golden Spread Elec. Coop Same	St Ofc Admin Hearings	SOAH 473-95-1820 PUC No. 15100	04-96
Piedmont Natural Gas Co.	North Carolina U.C.	G9, SUB 382	05-96
United Cities Gas Co.	Georgia P. S. C.	6691-A	05-96
Piedmont Natural Gas Co.	Tennessee P.S.C	PSC 96-00977	05-96
Golden Spread Elec. Coop Same	St Ofc Admin Hearings	SOAH 473-95-1708 PUC No. 14980	05-96
United Cities Gas Co.	Virginia C.C.	PUE950008	08-96
Piedmont Natural Gas Co.	North Carolina U.C.	G9, SUB 382	10-96
Empire District Electric Co.	Missouri P.S.C.	ER97-81	10-96
Oklahoma Gas & Elec. Co.	Oklahoma C.C.	PUD 96-0000116	10-96
Atmos Energy Corporation Same	Illinois C.C.	Case No. 96-0437	10-96 01-97
Piedmont Natural Gas Co.	Tennessee P.S.C	PSC 96-00977	11-96
United Cities Gas Co.	Illinois C. C.	PSC 6691-A	11-96
Tri State Chemicals, Inc.	US Dist W Oklahoma	CIV-96-0174-T	12-96
ONEOK, Inc.	Oklahoma C.C.	97WSRG-486MER	3-97
United Cities Gas Co. Div. Atmos	Illinois C. C.	Doc No. 96-0618	4-97
Greeley Gas Div Atmos Energy	Colorado P. U. C.	97F-221G	10-97
Southern Disposal v TX Waste Mgmt	US Dist E Oklahoma	CIV-97-115-S	12-97
Empire District Electric Co.	Arkansas PSC	Filing	2-98

 * Copy not available

ONEOK, Inc.	Oklahoma C.C.	PUD 980000177	6-98
ONG Transmission Company	Oklahoma C.C.	PUD97000088	10-98
Powder River Energy Corp.	Wyoming PSC	10014-CR-97-31	11-98
Universal Fidelity Life Ins Co	Ins Commisnr St of OK	97-201-TRN	12-98
ONG Transmission Company	Oklahoma C.C.	PUD 970000088	1-99
Tri-State G&T/Plains Elec G&T	New Mexico PRC	Case Filed	03-99
Tri-State G&T/Plains Elec G&T Same	Colorado P. U. C.	98A-511E	03-99 04-99
Trans Louisiana Gas Company	Louisiana PSC	U-21922	3-99
Trans Louisiana Gas Company	Louisiana PSC	U-21922	5-99
Oklahoma Natural Gas Co. Same Same	Oklahoma C.C.	PUD 980000683 PUD 980000570 PUD 980000166	5-99

• Copy not available

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 6
Witness: Donald A. Murry

Data Request:

Refer to page 6 line 20 of your pre-filed testimony. Please explain and provide an example how the 6.10 percent cost rate for short-term debt was calculated.

Response:

Dr. Murry obtained this information from Western Kentucky Gas Company's application Schedule J-1, Volume 10, Tab 10.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 7.a.
Witness: Donald A. Murry

Data Request:

Refer to page 18 lines 5-7 of your pre-filed testimony. You indicate that you considered the need to raise capital in the future rather than making a floatation cost adjustment when you evaluated the DCF results.

a. What did you consider to be Western Kentucky Gas Company's need to raise capital in the future?

Response:

As stated in Dr. Murry's Direct Testimony, there are a number of factors, in addition to the consideration of flotation costs, that required judgement regarding the appropriateness of the calculated cost of capital for ratemaking using the DCF and the CAPM methodologies. The reason for not including a flotation cost adjustment was not because of the need to raise capital in the future exclusively.

a. In the analysis, Western Kentucky's future capital requirements were assumed to be the normal growth and refinancing needs.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 7.b.
Witness: Donald A. Murry

Data Request:

b. How did you use your consideration when you made your final recommendation?

Response:

b. The future capital needs were considered to be typical for a gas distribution company.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 8
Witness: Donald A. Murry

Data Request:

Refer to page 19, beginning at line 10. You indicate that you used a method to adjust for "size bias" because Atmos is smaller than three of the companies you selected for comparison purposes. At the bottom of page 19, you indicate that the CAPM results are 11.68%. On the next page, when you adjust for size bias, you results are 11.31%. Please explain.

Response:

The size bias adjustment in using the Ibbotson Associates data applies to all firms, and its appropriateness is not based on Atmos being smaller than some of the Moody's firms. In applying this method, I applied the size adjustment accordingly, as shown in Schedule DAM-17.

The results cited in the question are from two different CAPM methodologies as set forth in DAM-16 and DAM-17. The size bias adjustment is appropriate only for the one for which it was applied. Please see the Response to AG1-9.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 9
Witness: Donald A. Murry

Data Request:

Refer to Schedule DAM-17. Please explain, and provide an example using data for Atmos Energy Corporation, how the size premium shown in the next to the last column was calculated.

Response:

Dr. Murry did not calculate the size premium. He obtained the size adjustment from *Ibbotson Associates, Stocks, Bonds, Bills and Inflation 1999 Yearbook.* Please see attached.

Table 8-1 **Key Variables in Estimating the Cost of Capital**

	Value
Yields (Riskless Rates)*	
Long-term (20-year) U.S. Treasury Coupon Bond Yield	5.4%
Intermediate-term (5-year) U.S. Treasury Coupon Note Yield	4.7
Short-term (30-day) U.S. Treasury Bill Yield	4.5
Risk Premia**	
Long-horizon expected equity risk premium: large company stock total returns minus long-term government bond income returns	8.0
Intermediate-horizon expected equity risk premium: large company stock total returns minus intermediate-term government bond income returns	8.4
Short-horizon expected equity risk premium: large company stock total returns minus U.S. Treasury bill total returns†	9.4
Expected default premium: long-term corporate bond total returns minus long-term government bond total returns	0.4
Expected long-term horizon premium: long-term government bond income returns minus U.S. Treasury bill total returns†	1.4
Expected intermediate-term horizon premium: intermediate-term government bond income returns minus U.S. Treasury bill total returns†	1.0
Size Premia***	
Expected mid-capitalization equity size premium: capitalization between $918 and $4,200 million	0.5
Expected low-capitalization equity size premium: capitalization between $252 and $918 million	1.1
Expected micro-capitalization equity size premium: capitalization below $252 million	2.6

* As of December 31, 1998. Maturities are approximate.

** Expected risk premia for equities are based on the differences of historical arithmetic mean returns from 1926–1998. Expected risk premia for fixed income are based on the differences of historical arithmetic mean returns from 1970–1998.

***See Chapter 7 for complete methodology.

† For U.S. Treasury bills, the income return and total return are the same.

Note: An example of how these variables can be used is found with equation (35).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 10
Witness: Donald A. Murry

Data Request:

Refer to Schedule DAM-17. Please provide citations for all published financial or economic research in refereed journals that indicate the justification or need for a size bias adjustment in the CAPM and which supports the method that you used.

Response:

Dr. Murry does not know or possess a list of all financial or economic publications regarding the size adjustment bias to the CAPM. The following are prominent articles on the subject:

Fama, F. F. and French, K. R., "The Cross Section of Expected Stock Returns," Journal of Finance, June 1992, pp. 427-465.

Banz, R. W., "The Relationship Between Return and Market Value of Common Stock," Journal of Financial Economics, March 1981, pp. 3-18.

Reinganum, M. R., "Misspecification of Capital Asset Pricing: Empirical Anomalies Based on Earnings, Yields and Market Values," Journal of Financial Economics, March 1981A, pp. 19-46.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 11
Witness: Donald A. Murry

<u>Data Request:</u>

Refer to Schedule DAM-17. Please cite and provide the a copy of the page or pages for the source of the 8.00% equity risk premium shown in the fourth column from the right hand side of the Schedule.

<u>Response:</u>

Please see the Response to AG1-9.

12

RECYCLED 10% P.C.W.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 12
Witness: Donald A. Murry

Data Request:

Refer to Schedule DAM-16. Please cite and provide a copy of the page or pages for the source of the 15.30% Market Total Return shown in the first column of the Schedule.

Response:

The 15.3% Total Market Return is the average of the arithmetic means of large company stocks' total returns (13.2%) and the arithmetic mean of small company stocks (17.4%) from *Ibbotson Associates SBBI 1999 Yearbook*. Please see the attached.

Table 6-7 **Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes**

Summary Statistics of Annual Returns

From 1926 to 1998

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	11.2%	13.2%	20.3%	0.01
Income	4.5	4.5	1.4	0.84
Capital Appreciation	6.5	8.4	19.6	0.01
Small Company Stocks				
Total Returns	12.4	17.4	33.8	0.09
Long-Term Corporate Bonds				
Total Returns	5.8	6.1	8.6	0.10
Long-Term Government Bonds				
Total Returns	5.3	5.7	9.2	-0.01
Income	5.2	5.2	2.9	0.97
Capital Appreciation	0.0	0.3	8.0	-0.17
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.18
Income	4.8	4.8	3.0	0.96
Capital Appreciation	0.4	0.5	4.4	-0.19
Treasury Bills				
Total Returns	3.8	3.8	3.2	0.92
Inflation	3.1	3.2	4.5	0.65

Total return is equal to the sum of three component returns; income return, capital appreciation return, and reinvestment return. Annual reinvestment returns for select asset classes are provided in Table 2-6.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 13
Witness: Donald A. Murry

Data Request:

Refer to Schedule DAM-16. Please provide citations for all published financial or economic research in refereed journals that indicate that long-term corporate bonds should be used to determine the risk premium for use in the CAPM.

Response:

Dr. Murry does not know or have access to all published financial or economic research in refereed or nonrefereed publications that use corporate bonds in a risk premium method to estimate the cost of capital. A general, representative source is Morin, Roger A., *Regulatory Finance,* Public Utilities Reports, Inc. 1994, pp. 269-297. Specifically, this chapter, "Risk Premium" describes a number of such methods used in regulatory proceedings.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 14
Witness: Donald A. Murry

Data Request:

Refer to Schedule DAM-16. Please provide citations for all published financial or economic research in refereed journals that indicate that a different interest rate proxy should be used to determine a risk premium required by CAPM than the rate added back to the risk premium to determine the required cost of equity. (This is in reference to your use a long-term corporate bonds return to determine the risk premium and the Aaa Corporate Bonds Return to determine the cost of equity.)

Response:

The Aaa bond rate is the current bond rate that Dr. Murry used to estimate the current cost of common stock. A methodology that does not follow the principle of matching data to the period of estimation is a biased methodology. Moreover, using the Aaa bond as a measure of current market debt costs is conservative because a bond with a lower rating will normally be higher cost, and a higher cost bond results in a higher estimated cost of common equity.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 15
Witness: Donald A. Murry

Data Request:

Refer to page 20, line 7. You indicate that you considered the financial market's assessment of the shifting risks between the interstate transmission companies and the local distribution companies. What were your considerations in this regard and how did you quantify them?

Response:

As Dr. Murry's Direct Testimony explains at page 21, and Schedule DAM-18 shows, the market valuation of common stock of the gas distribution companies has been less than that of the transmission companies during recent months. As Dr. Murry's testimony explains, one reason for this market perception may be the risk associated with regulation since there is a significant, recent distinction between the gas transmission companies and the gas distribution companies. This market evidence was used to evaluate and interpret the cost of capital information, which also has been noted by analysts. See, for example, the Response to KPSC DR1-62.a., especially the report by A. G. Edwards, "Gas Utilities" Annual Productivity," page 6.

> Although some of this decline could be weather related, we have seen evidence that many gas utilities are becoming more cautious in their capital expenditure programs. The current regulatory trend of lower allowed returns and reluctant rate relief has led to more calculated plans for system expansion. Many utilities have stated they can no longer afford to offer service to certain nonprofitable customers due to the uncertainty of future rate relief.

Schedule DAM-18 is a graph of the market price indices of the Dow Jones industrials, the Moody's gas transmission companies and Moody's gas distribution companies. These data are converted to a base index for comparison. There has been no further attempt to quantify the differences

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 16
Witness: Donald A. Murry

Data Request:

Refer to page 20, line 7. You indicate that you considered the financial market's assessment of the shifting risks between the interstate transmission companies and the local distribution companies. Please provide copies of all studies that you have done, or have read, that indicates how the financial market assesses the shift of risk between the interstate transmission companies and the local gas distribution companies.

Response:

Dr. Murry does not have a list of all studies that he has read or prepared concerning the risk of gas companies. Please see the attached partial list from his files.

A State Regulatory Strategy for the Transitional Phase of Gas Regulation

Frank P. Darr†

This Article addresses the transitional period of natural gas deregulation under the Federal Energy Regulatory Commission's recently promulgated Order No. 636. Regulation of the natural gas industry is complicated because although production is competitive, transportaion and local delivery systems remain monopolistic. Order No. 636 requires gas pipelines to act as common carriers and therefore shifts the locus of regulation to local distribution companies (LDCs). This change means that small customers unable to switch gas suppliers will likely face higher gas costs. Changes in the manner of calculating rates and fuel-switching capabilities by larger purchasers encourages this shift in cost. Additionally, deregulation of gas provision will increase the exposure of LDCs to fluctuations in gas price and availability. This Article proposes that state regulators adopt a system of advanced planning and incentive rate setting. Primarily this involves setting target gas cost ranges for LDCs based on a mix of spot and longer-term contract prices for natural gas and a sharing of gains and losses by the utility and its customers. Using planning, utilities and regulatory commissions can reduce the amount of regulatory risk inherent in the changing environment. By explicitly allowing some risk sharing, state commissions can encourage utilities to take advantage of competitive opportunities in gas commodity markets to the benefit of both large and small gas customers.

†Associate Professor, Ohio State University. B.A., University of Akron, 1979; J.D., Ohio State University, 1982. Earlier versions of this Article were presented at the Biennial Regulatory Information Conference and the Midwest Academy of Legal Studies in Business.

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> *"In your supply contracts, no matter what way you go—if you tie your supplies to indexes, to futures or to fixed prices—something will go wrong. It's just the nature of things."*[1]

Introduction

During the 1970s and 1980s, the natural gas market surged from shortage to oversupply as prices fluctuated unpredictably.[2] Industry laid much of the blame for these swings in price and availability upon regulation.[3] Consumers claimed that attempts to control gas pricing[4] saddled them with both gluts and shortages. Likewise, regulation of pipeline and distribution companies met with

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1. Donald Dodson, *Impact of SFV Rates, Transition Costs Overstated, Analysts Argue*, INSIDE F.E.R.C., Nov. 29, 1993, at 11 (quoting John Bilardello speaking before Standard & Poor's annual banking conference).

2. CHARLES F. PHILLIPS, JR., THE REGULATION OF PUBLIC UTILITIES 630-33 (2d ed. 1988); L. K. Harrington, *Law and Operations Under Order 436: Solving the Problems*, 1 NAT. GAS L.J. 98, 99 (1986).

3. *See generally* PHILLIPS, *supra* note 2, at 628-53. Richard Vietor suggests that regulation and market structure were closely intertwined. RICHARD H.K. VIETOR, CONTRIVED COMPETITION: REGULATION AND DEREGULATION IN AMERICA 91-166 (1994). He writes that "the real substance of business-government relations was the indirect impact of regulatory policy on the firm through its effects on market structure and political interest groups." *Id.* at 92.

4. Over the protests of the Federal Power Commission (FPC), the Supreme Court, in 1954, declared that the FPC had jurisdiction over wellhead pricing. Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

substantial criticism. In response to such criticisms, federal regulators, sometimes with the approval of Congress, began a process of deregulating the natural gas business.[5] The most recent step toward deregulation is the Federal Energy Regulatory Commission's Order No. 636.[6]

Order No. 636 eliminates the responsibility of interstate pipelines for moving their own gas from the field to the city gate. The Federal Energy Regulatory Commission (FERC) has ordered the pipelines to unbundle and reprice their services so that their customers—mainly local gas distribution companies, municipal authorities, and industrial customers—can package their gas service to include the best-priced combination of gas commodity and transportation.[7] The deregulation methods employed in Order No. 636 are consistent with the basic economic models used in recent years to deregulate other traditional utility services.[8]

Far from removing the regulatory framework from gas sales, Order No. 636 shifts the regulatory focus to the last link in the distribution chain: the state regulated distribution company. Several factors make this shift inevitable. First, mandated change in market structure results in a dramatic shift of costs from customers with choices to those without.[9] Second, the local distribution

5. Congress began the process by decontrolling the wellhead price of natural gas as part of the major energy law reforms enacted in 1978. Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350 (codified as amended at 15 U.S.C. §§ 3301-3432 (1988)). Congress directed full price decontrol in the Natural Gas Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (codified at 15 U.S.C. §§ 3301-3432 (1988 & Supp. 1993)). The Federal Energy Regulatory Commission has used its prior legislative authority to begin decontrolling the use of gas transportation. *See* Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 Fed. Reg. 30,334 (1987) (Order No. 500), *remanded*, American Gas Ass'n v. FERC, 888 F.2d 136 (D.C. Cir. 1989); Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 Fed. Reg. 42,408 (1985) (Order No. 436), *vacated and remanded*, Associated Gas Distrib. v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988).

6. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation, 57 Fed. Reg. 13,267 (1992) [hereinafter Order No. 636], *reh'g granted in part and denied in part*, 57 Fed. Reg. 36,128 (1992) [hereinafter Order No. 636-A], *reh'g denied*, 57 Fed. Reg. 57,911 (1992) [hereinafter Order No. 636-B], *appeal pending*, Atlanta Gas Light Co. v. FERC, No. 92-8782 (11th Cir. filed Aug. 13, 1992). On February 15, 1994, the cases were transferred to the Court of Appeals for the District of Columbia. *Order 636 Challenges Transferred to D.C. Circuit Appeals Court*, ENERGY DAILY, Feb. 24, 1994. The chance of reversal appeared to diminish when the District of Columbia Circuit Court of Appeals approved individual utility proposals to unbundle the utility's transportation and sales. Elizabethtown Gas Co. v. FERC, 10 F.3d 866 (D.C. Cir. 1993).

7. These changes are codified at 18 C.F.R. §§ 284.1-284.402 (1994).

8. For similar approaches to telecommunications based on assumptions that industry segments are competitive, see PETER W. HUBER ET AL., THE GEODESIC NETWORK II: 1993 REPORT ON COMPETITION IN THE TELEPHONE INDUSTRY (1993) (local telephone service); PETER W. HUBER, U.S. DEP'T OF JUSTICE, THE GEODESIC NETWORK: 1987 REPORT ON COMPETITION IN THE TELEPHONE INDUSTRY (1987) (interLATA telephone service and manufacturing). *See generally* Mark S. Fowler et al., *"Back to the Future": A Model for Telecommunications*, 38 FED. COMM. L.J. 145 (1986). Significant changes are also underway in the regulation of electricity. The Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992), initiated changes in the basic structure of electric generation and transportation, and California announced a proposal in April 1994 for direct competition in the sale of electric power. Andy Pasztor & Dave Kansas, *Regulators Propose Direct Competition for Providing Electricity in California*, WALL ST. J., Apr. 21, 1994, at A11.

9. *See infra* notes 82-86 and accompanying text.

companies (LDCs) face increased risk in determining gas supplies and securing regulatory approval for those choices. This increased risk will be reflected in higher costs of securing capital, a major component of gas utility rates.[10] In addition to higher costs, LDCs are now more likely to lose industrial customers to competing gas sellers.[11] Finally, the company is likely to have more difficulty providing its basic service: as an LDC increasingly relies on contracting with multiple suppliers in lieu of a single pipeline with a tariffed duty to serve, the LDC runs the risk of incurring the wrath of its state regulator if and when gas providers fail.[12]

In response to these concerns, state regulatory commissions are likely to increase their scrutiny of LDC gas purchasing practices. The tools available to the commissions—prudence reviews, integrated resource planning, and incentive rate setting—are problematic. In particular, some tools provide incentives that are contrary to the goal of benefiting customers with low-cost and reliable service.[13] The alternative, deregulation, is not the answer because portions of the LDC market are not competitive.[14] Given this commercial reality, commissions will have to take some role in regulating the noncompetitive segment of the gas market.

Until it is clear what type of industrial structure will emerge in the distribution of natural gas and whether traditional forms of regulation remain necessary, some form of transitional regulation will be required. Based on the current trends in regulation and policy, it appears likely that a policy will emerge that attempts to provide incentives for LDCs to enter the marketplace aggressively while partially protecting core customers. One approach may employ advanced planning and incentive rate setting. Planning tends to assure both the utility and the commission that reasonable efforts are being made to take advantage of emerging gas opportunities. Incentives provide the utility with the encouragement it may need to undertake the newly-created risks. In addition, the commissions may have to take a critical look at the way that they price interruptible service and transportation rates. The effects of such bypass (such as the direct purchase of gas or the use of alternative fuels), however,

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10. *Credit Risks for Regulated Industries Rise Due to Deregulation, Moody's Says*, DAILY REP. FOR EXECUTIVES, Feb. 9, 1994, at A24; *Increased Risk Will Cloud Distributors' Credit Ratings, Says Moody's*, INSIDE F.E.R.C., Aug. 30, 1993, at 1 [hereinafter *Increased Risk*]; *Moody's Report Concludes Order No. 636 Will Shift Credit Risks from Pipelines to LDCs*, FOSTER NAT. GAS REP., Aug. 26, 1993, at 7 [hereinafter *Moody's Report*].

11. *See infra* notes 89-90 and accompanying text.

12. This jeremiad should not suggest that the changes are all negative. For some customers, new cost saving measures are likely to emerge. Likewise, whole new forms of risk management may appear. Carol Freedenthal, *The Gas Industry's Newest Commodity*, FORT., Apr. 1, 1994, at 30. For others, however, the transition will be costly, and regulators will have to justify their actions to various political audiences.

13. *See* discussion *infra* Part II.C.

14. *See infra* text accompanying notes 25-26.

may not be as significant a problem as the industry's jeremiads seem to suggest.

This Article explores a potential transitional regulatory scheme based on the conclusions set out above. The first part briefly explains the structure of the natural gas industry and its regulation, and notes the changes and new risks created by Order No. 636 for LDCs and their core customers. Part II reviews the traditional form of cost regulation used by state commissions to price utility service and the options state commissions have to address utility management decisions. This part concludes that the common forms of regulation, by themselves, do not offer the kinds of protection utility commissions are likely to find acceptable. Finally, Part III identifies some common assumptions about the emerging marketplace and proposes a combination of gas purchase planning and incentive rate making to assure reliable, low-cost service.

I. Structural and Regulatory Background of Order No. 636

The changes directed by Order No. 636 are rooted in both the structure and the regulation of the gas industry. Transportation and significant portions of the sales market in the natural gas industry exhibit classic elements of natural monopoly or oligopoly. This structure leads to the adoption of public utility regulation. Production of natural gas is, however, potentially competitive. Attempts to regulate production as if it were a monopoly result in economic distortions. The industry's dual nature, monopolistic and competitive, inspired a rethinking of gas regulation and ultimately Order No. 636.

A. *The Industrial Structure of Gas Sales*

Both the physical and financial size of the gas industry are impressive. A 1992 report estimated distribution and transmission facilities at 1.25 million miles.[15] Total deliveries (sales and transportation) exceeded 15 quadrillion Btu.[16] In 1991, gas represented approximately one-quarter of total energy usage in the United States.[17] The plants dedicated to serve that usage were valued at $129 billion.[18]

There are two other important factors relating to gas usage. First, despite subsidies historically built into rate structures, the cost of gas delivered to

15. AMERICAN GAS ASS'N, GAS FACTS: 1992 DATA 61 (1993).
16. *Id.* at 67. Sales constituted nearly 10 quadrillion Btu, with transportation providing the balance. Residential deliveries amounted to 4.7 quadrillion Btu, commercial to 2.2 quadrillion Btu, and industrial to 2.8 quadrillion Btu. *Id.*
17. *Id.* at 124.
18. *Id.* at 153.

residential customers is nominally high relative to the cost to other classes of customers.[19] This translates into a substantial residential revenue base equal to more than half of the utilities' gross income.[20] Second, even with the substantial and essentially constant industrial use, total gas sales are highly seasonal, with sales increasing dramatically during the winter months.[21]

The business of moving gas from well to user is a multistep process of gathering, transmission, and distribution.[22] The first step entails drilling a productive well and moving the gas to a transmission pipeline through collecting or gathering pipelines. With thousands of producers, this stage of the process is relatively competitive.[23] The cost of gas can, however, vary greatly across regions.[24]

The process of moving gas to the end user is less competitive.[25] Since World War II, transmission of gas has been accomplished through large, high-pressure pipelines that extend for hundreds of miles from gathering areas located primarily in the Southwest to other parts of the country. These capital-intensive businesses tend to serve distinct areas with little head-to-head competition with other gas companies (although there is indirect competition from other sources of energy, such as electricity and oil). The pipeline served as a bottleneck to the sale of gas. Likewise, when the gas neared the end user, a monopoly provider, a LDC, controlled distribution. Authorized by state law, these monopolies laid the last set of lines and pressure facilities that moved

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19. In 1992, the average residential rate for approximately 1,000 cubic feet of gas was $5.69. Commercial customers paid $4.92, and industrial customers paid $2.56. *Id.* at 107. Note that 1,000 cubic feet ≈ 1 MMBtu.

20. In 1992, residential revenues amounted to $26.7 billion, commercial to $10.9 billion, and industrial to $7.9 billion. *Id.* at 87.

21. *Id.* at 72-73.

22. For a simple diagram of the gathering, transmission, and distribution process for natural gas, see VIETOR, *supra* note 3, at 102.

23. *See* PHILLIPS, *supra* note 2, at 633, 644-45. Hatcher and Tussing state:

> The phased decontrol of wellhead natural gas prices under the [Natural Gas Policy Act] had a profound effect on the industry's structure. The buying and selling of natural gas as a commodity, distinct from its transportation, became a textbook illustration of near-perfect competition—thousands of buyers and sellers trading a homogenous commodity at prices and according to contract terms that suited their separate needs. This reliance on forces of supply and demand to establish prices, in lieu of government formulas or fiat, was the first of three preconditions for the emergence of a competitive gas procurement sector.

David B. Hatcher & Arlon R. Tussing, Occasional Paper No. 15, State Regulatory Challenges for the Natural Gas Industry in the 1990s and Beyond 7 (June 1992) (unpublished manuscript, on file with Journal).

24. *See* AMERICAN GAS ASS'N, *supra* note 15, at 108 (noting 1991 Texas wellhead price of $1.59/Mcf and Michigan price of $2.79/Mcf).

25. Concentration was noted as a problem relatively early in the industrial history of natural gas:

> By 1932 the natural gas industry was concentrated horizontally and vertically. The same four holding companies were the largest four companies in each sector of the business—production, transmission, and distribution. Only the ranking varied . . . . The four-firm concentration in gas production was only 16 percent, but in interstate transmission it was 56 percent, and in distribution, about 60 percent.

VIETOR, *supra* note 3, at 98.

the gas to the burnertip. To each community's customers, the transmission of gas, and the purchase of the gas itself, was and remains a monopoly enterprise.[26]

Based on the three-tiered transportation structure and the existing scheme of regulation, fixed long-term contracts became a standard feature of gas sales and transportation.[27] Both pipelines and LDCs obtained gas through long-term (twenty-year) contracts. Under these contracts, the LDCs agreed to pay for minimum amounts of gas (whether it was transported or not), while the pipelines guaranteed peak amounts (contract requirements).[28] This process remained relatively stable until the 1970's when price escalation broke the symmetry of the relationship.[29]

B. *The Changing Regulatory Structure*

Against this mixture of competition and market power, the regulatory scheme developed under a traditional natural monopoly model. The Natural Gas Act[30] assigned the Federal Power Commission (now FERC) the responsibility of setting prices for transmission and certain resales of gas. Eventually, jurisdiction was extended to wellhead prices. In time, fundamental problems with gas supplies emerged contemporaneously with significant regulatory problems. In reaction, Congress and the Commission began a process of deregulating the price of gas and separating the gas-merchant function from the gas-transmission function. These steps lead to Order No. 636.

The initial federal regulation, the Natural Gas Act, approached gas regulation as a traditional utility monopoly problem.[31] In the traditional model of welfare economics, regulation is justified to correct market failures that lead

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26. Harry G. Broadman & Joseph P. Kalt, *How Natural Is Monopoly? The Case of Bypass in Natural Gas Distribution Markets*, 6 YALE J. ON REG. 181, 197-98 (1989) (describing natural monopoly-like characteristics of gas distribution); Suedeen G. Kelly, *Intrastate Natural Gas Regulation: Finding Order in the Chaos*, 9 YALE J. ON REG. 355, 369 (1992) (noting most customers continue to receive bundled service from LDC).

27. *See generally* Paul W. McAvoy et al., *Is Competitive Entry Free? Bypass and the Partial Deregulation in Natural Gas Markets*, 6 YALE J. ON REG. 209, 216 (1989).

28. Daniel J. Duann, *The FERC Restructuring Rule: Implications for Local Distribution Companies and State Public Utility Commissions*, 93-12 NAT'L REG. RES. INST. 31-32 (1993).

29. *Id.* at 32-33.

30. 15 U.S.C. §§ 717-717w (1988).

31. In the late 1920s, the Federal Trade Commission conducted a study that became the basis for regulation of the gas market. *See* Vanessa A. Richelle, *Reworking Relationships in the Natural Gas Industry: Exploring the New Spot-market and its Operation*, 68 TUL. L. REV. 655, 657 (1994). The study identified carriage as the problem and suggested the need for common carriage of natural gas. Congress, however, rejected the common carriage approach and instead adopted a price regulation model similar to that used in the Federal Power Act. Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 ENERGY L.J. 1, 6 (1988).

to inefficiency.[32] Direct price regulation is often used against monopolies that develop due to scale production factors or specific government decree. In the case of a natural monopoly, the government may intervene to prevent the monopolist from using its market power to raise prices above competitive levels.[33] Such regulation dictates average cost prices to the natural monopolist as a substitute for the market's marginal pricing mechanisms.[34]

The rate-making formula used by commissions to determine the overall revenue to which a utility is entitled is deceptively innocent looking:

Revenue = Operating Expenses + (Rate of Return)(Rate base).[35]

Generally, expenses are the variable costs associated with providing service. These costs include wages, fuel costs, taxes, and depreciation of equipment.[36] Rate base is the capital equipment necessary to provide the required service.[37] Rate of return is the weighted average of the cost of debt and equity necessary to finance utility operations.[38]

Not all equipment owned by the utility can be included in the rate base. First, only equipment used for activities that are related to utility operations is included.[39] Second, commissions will reduce the rate base for the depreciation of equipment.[40] For those items properly included in the rate base there is an additional hurdle: the company must demonstrate that the costs of a capital item were prudently incurred.[41] At issue is the reasonableness of the costs of the investment in the new plant.[42] To the extent that the costs are

32. Peter H. Aranson, *Theories of Economic Regulation: From Clarity to Confusion*, 6 J.L. & POL. 247, 249-50 (1990). In addition to the natural monopoly rationale, an industry may be regulated so that its prices reflect the full costs of its production. For example, the regulation of polluting industries is designed to internalize the external costs imposed by pollution. *Id.* at 250-52. Regulation may also be used to reverse the effect of informational failures. For example, "[a] role for government may arise if workers remain ignorant of [a] risk to their health . . . . [G]overnment may exploit its coercive sanction and economies of scale in the collection, analysis, and dissemination of information to overcome this problem." *Id.* at 254. This traditional explanation for regulation, however, has suffered significant attacks from all corners of the academic world. VIETOR, *supra* note 3, at 311-16. *See also* ROBERT B. HORWITZ, THE IRONY OF REGULATORY REFORM 22-45 (1989). Nonetheless, information failure serves as a starting point for explaining the basic model of regulation.

33. Aranson, *supra* note 32, at 255-58; Pierce, *supra* note 31, at 2-3.

34. Under marginal pricing, a utility would not recover the costs of providing the service because its marginal cost would always be below its average cost in the relevant market area. JAMES C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 434 (2d ed. 1988).

35. ERNEST GELLHORN & RICHARD J. PIERCE, REGULATED INDUSTRIES 89 (2d ed. 1987); RICHARD A. POSNER, ECONOMIC ANALYSIS OF LAW 347 (4th ed. 1992).

36. PHILLIPS, *supra* note 2, at 244.

37. GELLHORN & PIERCE, *supra* note 35, at 107.

38. *See generally* BONBRIGHT ET AL., *supra* note 34, at 302-39.

39. GELLHORN & PIERCE, *supra* note 35, at 107-08.

40. *Id.* at 131-34; JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 192-223 (1961).

41. GELLHORN & PIERCE, *supra* note 35, at 109-11.

42. The reasonableness calculus applied to the cost of a capital item can be understood as follows:

> Partial exclusion of an asset on grounds of prudence usually occurs in one of three

deemed unreasonable, the investment cannot be included in the rate base of the company and the investors are precluded from earning a return on it.[43]

Operating expenses are likewise subject to a two-step analysis. First, the expense must be related to the provision of service to customers. Commissions have disallowed a variety of expenses such as excess wages, advertising expenses, and charitable contributions on the belief that these do not contribute to the provision of service to customers.[44] Second, even if the expense is related to the production of service, the utility may only charge a reasonable cost for it.[45] In summary, "regulatory agencies retain the authority to exclude costs from allowable revenues where the costs are not reasonably necessary for providing the service . . . and to reduce the amounts requested if they are unreasonable and excessive."[46]

Initially, the Federal Power Commission regulated only transmission facilities of interstate pipelines.[47] In 1954, over the Commssion's objection,[48] the Supreme Court extended the jurisdiction of the Commission to include the setting of the wellhead price of gas.[49] Thus, the Commission began a difficult period of attempting to regulate the gas sales of thousands of gas drillers. Initially, the Commission attempted to price each sale on an individual cost-of-service basis. When this process bogged down due to the sheer volume of the undertaking, the Commission substituted regional and later national pricing rules in an attempt to clear the regulatory gridlock.[50] Prices, however, lagged behind costs, and shortages developed.[51] In the 1970s, perceived shortages and general economic malaise led Congress to reevaluate

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> situations—when the firm imprudently experiences cost overruns in constructing an asset, when the firm pays too much to purchase an asset, or when the firm imprudently invests in an asset with a capacity greater than necessary to provide the regulated product in sufficient quantity.

Id. at 110.

43. As noted in the basic formula, exclusion from the rate base results in no recovery of a return on that asset. Likewise, a commission will not permit amortization (depreciation expense) of the imprudently incurred costs. *In re* Wolf Creek Nuclear Generating Facility, 70 Pub. Util. Rep. 4th (PUR) 475 (Kan. State Corp. Comm'n 1985), *aff'd*, Kansas Gas & Elec. Co. v. State Corp. Comm'n, 720 P.2d 1063 (Kan. 1986), *vacated in part*, 481 U.S. 1044, *and appeal dismissed*, Kansas City Power & Light Co. v. State Corp. Comm'n, 483 U.S. 1036 (1987). Thus, the total amount deemed imprudent is lost if no further adjustment is made in the rate of return to reflect the increased risk. Commissions are mixed in their treatment of this matter. *Compare id. with* Office of Consumers' Counsel v. Utility Comm'n of Ohio, 437 N.E.2d 586 (Ohio 1982).

44. JOSEPH P. TOMAIN ET AL., ENERGY LAW AND POLICY 166 (1989).

45. *Id.*; *see* PHILLIPS, *supra* note 2, at 246.

46. LOUIS B. SCHWARTZ ET AL., FREE ENTERPRISE AND ECONOMIC ORGANIZATION: GOVERNMENT REGULATION 525 (6th ed. 1985).

47. VIETOR, *supra* note 3, at 102-03.

48. Pierce, *supra* note 31, at 7-8.

49. Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954). Legislative gridlock furthered the move to regulate the wellhead price of gas. VIETOR, *supra* note 3, at 105-07.

50. For a discussion of the attempts to adopt pricing structures for gas, see Permian Basin Area Rate Cases, 390 U.S. 747 (1969). *See also* Pierce, *supra* note 31, at 8-9.

51. Pierce, *supra* note 31, at 10; Richelle, *supra* note 31, at 658-59.

the rules for pricing gas. As part of the 1978 energy legislation, Congress adopted the Natural Gas Policy Act (NGPA),[52] which over a series of years increased the allowable price for some gas and removed price controls on other gas, depending on the source and time of its discovery.

Partial decontrol of natural gas prices and the recession in the early 1980s turned shortages of gas into surpluses.[53] Pipelines that had contracted for gas under the higher NGPA schedules found that the gas was not marketable and began to lose sales from customers with the ability to switch to other fuels.[54] Unable to sell contracted-for gas, pipelines sought ways to reopen markets and increase the use of transportation (carriage of gas owned by a third party or a customer rather than the pipeline). Initially, the Commission approved Special Marketing Plans that permitted pipelines to sell gas to fuel switchers at reduced rates.[55] This program began to solve pipelines' problems of gas-surplus purchases, but it failed judicial review.[56] In response, the Commission adopted Order No. 436 (and subsequently Order No. 500 in response to judicial remands of the Commission's rulemaking in Order No. 436)[57] to provide mechanisms that allowed the conversion of contract-demand service to transportation.[58] In effect, the Commission directed the beginning of unbundling, as customers could now contract separately for gas and transportation.

Despite the significant conversion of supply purchasing to transportation during the initial years of the approach under Order No. 436,[59] the Commission concluded that the open transportation dictated by Order No. 436 failed to create an efficient marketplace in gas.[60] The Commission concluded that the pipelines' ability to control access to transportation and its quality resulted in an inefficient reliance on traditional bundled services (even while

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52. 15 U.S.C. §§ 3301-3432 (1988).

53. Duann, *supra* note 27, at 33.

54. Pierce, *supra* note 31, at 11. For example, an industrial gas customer might switch from gas to fuel oil.

55. PHILLIPS, *supra* note 2, at 472 n.91 (collecting cases).

56. Maryland Peoples Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985) (finding Special Marketing Programs unduly discriminatory).

57. *See supra* note 5 and accompanying text.

58. Broadman and Kalt have noted that the Orders and the then existing environment provided mixed incentives for bypass. On the one hand, the existing fixed contracts and rate structures encouraged bypass. On the other hand, reductions in contract demands and conversions to transportation reduced the need to leave the local distribution system. Broadman & Kalt, *supra* note 26, at 184-87.

59. Richelle, *supra* note 31, at 656 n.4 (noting spot-market purchases were approximately forty percent of interstate sales in 1986 and increased to seventy percent in 1988).

60. For the purists advocating deregulation, Order No. 436 fell short in several regards. It did not require pipelines to unbundle their services. More importantly for the courts and pipelines, Order No. 436 failed to address an important asymmetry: Pipelines remained liable to suppliers even while LDCs were being given the opportunity to forgo the purchase of existing contract requirements. For a succinct discussion of the minimum bill and take-or-pay problems caused by commission efforts to address the 1980s downturn in sales, see VIETOR, *supra* note 3, at 132-61.

more and more gas was in fact being transported for end users).[61] The Commission also found evidence that pipelines were discriminating in the quality of service they provided to end users that had migrated to transportation.[62] These findings led to the promulgation of Order No. 636.

C. *The Basics of Order No. 636*

To rectify the inefficiency created by pipelines' control of service quality, the Commission ordered that pipelines unbundle sales and transportation of gas.[63] Although an LDC could purchase both gas and transportation from a pipeline, gas would be sold separately from the transportation service necessary to move the gas to the end user. Moreover, the commodity price of gas would no longer be set by the Commission. The effect of these changes was to place the responsibility of ensuring gas for the end user on the LDC.

1. *Unbundled Sales and Transportation*

To avoid discrimination between sales and transportation, Order No. 636 requires pipelines to separate gas sales from transportation.[64] The Order also explicitly sets out a requirement that there should be no undue discrimination in the terms of sales and gas contracts.[65] In an attempt to permit greater flexibility and access to markets, the Order further provided for flexible delivery and receipt points, in other words, gas could be injected into the pipeline and taken from it at varying points according to need.[66] To enhance the available information concerning rates and available capacity, the rule requires pipelines to establish electronic bulletin boards containing rate and other contract information.[67]

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61. In its order, the Commission noted that transportation amounted to seventy-nine percent of total gas throughput on the interstate pipelines, but that LDCs had not exercised a similar amount of contract-demand reductions. As a result, LDCs were paying for fixed levels of service but receiving gas subject to conditions of interruptible service. Order No. 636, *supra* note 6, at 13,272-73. The Commission further noted that transportation was also limited by pipeline restrictions, lack of storage, and lack of access to upstream capacity. *Id.* at 13,275.

62. *Id.* at 13,275. The Commission buttressed its decision by finding that pipelines were injured by bundled service requirements and the use of weighted average costing for gas sold under regulation. Under such a pricing scheme, the pipelines could not compete for gas sales to parties who could contract separately for gas purchases. Buyers could purchase gas at lower marginal prices than those available through the pipeline and then contract for the particular level of service they wanted. As a result, buyers could avoid the averaged cost of gas and unwanted premiums associated with service reliability offered by the pipeline.

63. *Id.* at 13,277.

64. *See* 18 C.F.R. §§ 284.8(a)(1), 284.9(a)(1) (1994).

65. *Id.* §§ 284.8(b)(2), 284.9(b)(2). *See also* Order No. 636, *supra* note 6, at 13,282.

66. 18 C.F.R. § 284.221(g)-(h) (1994).

67. *Id.* §§ 284.8(b)(3)-284.8(b)(5), 284.9(b)(3)-284.9(b)(5).

A revised view of the market underlies the separation between sales and transportation. In its Orders, the Commission concluded that gas production was sufficiently competitive to permit markets to set pricing for the commodity.[68] Transportation, on the other hand, retained its monopoly status.[69]

2. *Encouraging Alternative Gas Sourcing*

To encourage the pipelines' existing firm customers to switch gas sources, the Commission also revised existing contract and tariff obligations. Initially, the Commission directed the conversion of firm rights to gas supplies (contract demand or CD rights) to a right to firm-no-notice transportation.[70] Under this rule, gas purchasers under existing firm-purchase contracts were entitled to the same daily firm amounts of transportation, but the buyers were now responsible for separately assuring that gas needed by their systems was available for transportation. The Commission also ordered that downstream pipelines transfer their capacity rights to upstream pipelines to end users.[71] To the extent that such transportation was not necessary, buyers were permitted to release capacity through pregranted abandonment.[72] Finally, the Commission defined transportation to include storage facilities.[73] The effect of this decision was to make storage a tariffed item available to end users on a nondiscriminatory basis.[74]

3. *Pricing Firm Transportation Service*

Consistent with other changes that attempted to increase the economic efficiency of pipeline service, the Commission also addressed transportation pricing. Before Order No. 636, the Commission usually assigned some portion of fixed costs to the incremental commodity charge for gas in order to encourage pipelines to seek customers for abundant supplies.[75] Because a fixed cost was added to a variable cost item utilities could only fully recover their fixed costs by using all of their capacity. The Commission found this

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68. Order No. 636-A, *supra* note 6, at 36,179.
69. Order No. 636, *supra* note 6, at 13,269.
70. *See* 18 C.F.R. § 284.8(a)(4) (1994). *See also* Order No. 636, *supra* note 6, at 13,287.
71. 18 C.F.R. § 284.242 (1994). *See also* Order No. 636, *supra* note 6, at 13,283.
72. 18 C.F.R. § 284.243 (1994). Typically abandonment (the termination of previously authorized service) requires Commission review of a specific request and a finding that abandonment is in the public interest. 15 U.S.C. § 717b (1988); 18 C.F.R. §§ 157.5-157.21 (1994).
73. 18 C.F.R. § 284.1 (1994).
74. In theory, and probably now in practice, end users could contract for storage so as to purchase gas when prices are low. Then they could hold the gas until it is needed and low-cost supplies are not available. The ability to store, however, is dependent on both storage rights and capacity rights.
75. Order No. 636, *supra* note 6, at 13,292.

pricing scheme inconsistent with the market-based pricing of gas and announced that it would no longer seek to shift fixed costs into the variable cost of gas. Instead, the Commission adopted a straight fixed-variable method for setting transportation rates in which all fixed costs would be assigned to the demand portion of the rate.[76] One obvious effect of this change was to shift costs from high-load/low-peak customers (industrial customers) to low-load/high-peak customers (LDCs serving residential customers).[77] Another effect was to put more pressure on firm contract holders to reduce the amount of demand charges by reducing firm no-notice transportation claims.

D. *The Apparent Effects of Order No. 636 on Local Regulation of Natural Gas*

Taken together, the rule changes in Order No. 636 placed a new set of burdens on local distribution companies. As the Commission offered: "It is true that the Commission has changed the terms and conditions of service and thereby subjected pipeline customers to more responsibilities, duties, and risks."[78] That assertion probably understates the result. The LDC, in particular, is now at risk for securing supplies to assure availability, avoiding curtailment of its transportation, and doing all of this at a reasonable cost. The LDC has become a portfolio manager of gas sources, a role unheard of until recently.[79]

This shift of risk to LDCs comes at the same time as another important regulatory policy. No longer will the doctrine of federal supremacy dictate the pricing of wholesale gas.[80] Instead, responsibility for reviewing the LDC's gas costs will shift to the states. As George Hall noted in a similar context: "[Public utility commissions] must confront such issues as whether LDCs are assuming an inappropriate amount of risk or are being sufficiently aggressive

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76. 18 C.F.R. § 284.8(d) (1994); Order No. 636, *supra* note 6, at 13,270; Order No. 636-A, *supra* note 6, at 36,173.

77. Order No. 636, *supra* note 6, at 13,270; Order No. 636-A, *supra* note 6, at 36,173. LDCs with a high proportion of residential sales face significant problems due to the purchasing patterns of their customers. The cost shift occurs because residential customers tend to buy at defined periods (particularly winter months) when the price of gas is highest and available capacity on a pipeline is at a premium. These peaks must be satisfied by the creation of capacity, a fixed cost. Since fixed costs are no longer shared with interruptible customers, inevitably, capacity costs shift back to remaining firm customers.

78. Order No. 636-B, *supra* note 6, at 57,912.

79. Order No. 636-A, *supra* note 6, at 36,166-67.

80. Extensive literature exists on federal preemption of state rate-making authority. For a listing of these articles and a discussion of the Supreme Court decisions, see Frank P. Darr, *Mitigating Costs and the Preemptive Effect of Federal Rate Orders*, 13 ENERGY L.J. 61 (1992). For purposes of this Article, it is assumed that the states will have the authority to review LDC purchasing practices. For the time being, that position is also the one adopted by the FERC. *See, e.g.*, Order No. 636-A, *supra* note 6, at 36,205.

in seeking bargains."[81] The balancing act will take place within the context of state reviews to determine the appropriate amount of gas costs that should be borne by utility customers.

Several factors make this shift of risk inevitable.[82] First, FERC's change to the straight fixed-variable method of rate setting results in a substantial shift of costs from customers with choices to those without. That is, industrial customers that have access to alternative providers of gas or those that can switch to alternate fuels will face reduced costs while residential and small commercial customers are likely to see higher ones.[83] Second, LDCs face increased risk in determining gas supplies and securing regulatory approval for those choices that will be reflected in higher costs to secure capital, a major component of a gas utility rate case.[84] This increased risk is also likely to be found in a company's ability to provide its basic service: as it relies to a greater extent on contracting with multiple suppliers in place of a single pipeline with a tariffed duty to serve, it incurs the risk that gas providers will fail and that the LDC will incur the wrath of its state regulators for those failures.[85] Indeed, increased regulatory risk, the risk that the markets will perceive a company as being underfunded due to state regulatory action, appears to be one of the dominant concerns arising from Order No. 636.[86] The combination of higher prices and less reliable service for politically powerful customers will likely lead to a disaster for regulators.

At the same time that it becomes more difficult to serve core customers, Order No. 636 creates additional pressures for bypass. "[B]ypass occurs when customers of the LDC turn to another gas provider such as an interstate,

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81. George R. Hall, *Getting Regulation from "Here" to "There"*, *in* DRAWING THE LINE ON NATURAL GAS REGULATION: THE HARVARD STUDY ON THE FUTURE OF NATURAL GAS 241, 260 (Joseph P. Kalt & Frank C. Schuller eds., 1987).

82. For an excellent discussion of the likely impacts of Order No. 636, see William P. Boswell, *The New Competitive Monopoly: A Thundering Silence*, FORT., Oct. 1, 1992, at 27.

83. Estimates vary as to the amount of redistribution of costs. *GAO Issues Final Report on Order No. 636 Economic Impacts*, FOSTER NAT. GAS REP., Nov. 11, 1993, at 1. The General Accounting Office estimates that the transfer will amount to approximately $1.2 billion annually. RESOURCES, COMMUNITY, & ECONOMIC DEV. DIV., U.S. GEN. ACCOUNTING OFFICE, NATURAL GAS: COSTS, BENEFITS, AND CONCERNS RELATED TO FERC'S ORDER 636, at 2 (1993) [hereinafter GAO REPORT]. In addition, local distribution companies will face new costs associated with acquiring gas that were not necessary under the prior regime. *Id.* at 4. *See also Local Distribution Company Post-Restructuring Issues Are Identified in GAO Report Appendices*, FOSTER NAT. GAS REP., Nov. 18, 1993, at 20. Finally, there will be significant one time charges associated with the conversion of existing gas contracts. According to the GAO, new costs associated with transition required under the rule amount to about $300 million. GAO REPORT, *supra*, at 10.

84. *Increased Risk*, *supra* note 10, at 1; *Moody's Report*, *supra* note 10, at 7.

85. *Increased Risk*, *supra* note 10, at 1; *Kansas State Regulator and East Coast Distributor Representative Explain to Energy Bar Conference Their Concerns About Economic Rationale and Cost Impact of Order No. 636-1927*, FOSTER NAT. GAS REP., May 13, 1993, at 5.

86. Craig S. Cano, *LDCs Want Market-Based Regulation, but States Need More Convincing*, INSIDE F.E.R.C., May 3, 1993, at 7; Phillip S. Cross, *Major Issues Remain for States as Order 636 Arrives*, FORT., Nov. 1, 1993, at 58; Dodson, *supra* note 1, at 11.

intrastate, or private pipeline; or start using a fuel other than gas . . . or invest in conservation measures to consume less gas."[87] The problem with bypass is that someone must absorb the share of the gas system's fixed costs that the bypassing customer is no longer paying.[88] Either the remaining customers will absorb these costs, shareholders' returns will decrease, or the company will have to reduce the costs of service, possibly by degrading existing levels of service.[89] As the interstate gas system opened during the 1980s, bypass became an increasing concern because gas producers were willing to sell gas to end users who found pipelines to transport the gas to their facilities.[90] Order No. 636 further encourages bypass by removing existing barriers to transportation and increasing an LDC's cost of purchasing firm gas from a pipeline (by the use of the straight fixed-variable rate methodology). The net effect is to increase the likelihood that the customers with the least economic power will face increased costs. Like the concerns about increased reliability, the bypass problem points to increased state scrutiny.

II. State Action on Order No. 636

While it seems reasonable to assume that state commissions will continue to increase their level of oversight, it is less clear what form this increased oversight will take. Traditional regulation has taken the form of cost-plus pricing and does not fit the emerging environment of partial competition. In addition, both the traditional forms of review and more recent efforts at resource planning and incentive pricing have their own significant problems.

A. *The Traditional Structure of Rate Regulation*

The existence of natural monopoly-like circumstances in gas distribution implicates the classic rationale for regulation. For at least some core customers, there are few or limited opportunities for alternative sources of gas.[91] Whether driven by the inherent economics of gas provision or the lack of alternative physical facilities, these core customers are locked into a single provider, the LDC.[92] The traditional model of regulation has thus been for

87. Kelly, *supra* note 26, at 360.

88. *Id.* For example, if the fixed costs of an LDC are $2 million a year and these are spread over 4 million units of gas, each unit of gas must carry a 50¢ charge per unit for fixed costs. If, for some reason, a large customer leaves the system and the gas sold by the LDC goes to 3.5 million units, the remaining customers will pay a 57¢ charge per unit for fixed costs.

89. Broadman & Kalt, *supra* note 26, at 203.

90. Kelly, *supra* note 26, at 360.

91. A distinction is commonly drawn between core and non-core customers. Non-core customers have fuel-switching options.

92. Hatcher & Tussing, *supra* note 23, at 13-14.

a commission to set prices using a rate-of-return formula. State commissions have responded in several ways to the changes required by Order No. 636.

B. *Formal State Actions in Response to Order No. 636*

One area of concern involves the transition costs that FERC permitted the pipelines to pass to LDCs.[93] Despite FERC's attempt, in its Order, to preempt state review, commissions have sought to address the manner in which costs will be transferred to LDC customers.[94] Likewise, some commissions are already attempting to address issues concerning the bypass of LDCs through rate structure reviews.[95] These types of claims could well be expected in light of FERC's stated goals in the rule change.

Rate-of-return levels are also ripe for reconsideration. LDCs, for example, are requesting increased rates of return as compensation for the increased risk they face in making supply choices.[96] In addition to the rather obvious request for a higher return on equity, there is also the potential for altered debt-equity structure. One Wisconsin utility sought to revise its approved structure so that it could assume additional short-term debt to finance storage costs.[97]

Much of the transitional work, however, remains to be done.[98] For example, states are struggling with the periodic filing requirements for gas purchases to accommodate the new obligations placed on LDCs.[99] At least two kinds of problems are likely to emerge. One is the technical treatment of newly identified costs, such as storage, that result from unbundling

93. *See supra* note 83 and accompanying text.

94. Statement of Policy Regarding the Recovery of FERC Order 636 Transition Costs, 1993 Pa. PUC LEXIS 77 (Oct. 15, 1993); Investigation into the Appropriate Recovery by Illinois Gas Utils. of FERC Order 636 Transition Costs, 1993 Ill. PUC LEXIS 387 (Sept. 15, 1993).

95. *In re* Application of Baltimore Gas & Elec. Co. for Revision of its Gas & Elec. Rates, 1993 Md. PUC LEXIS 99 (Apr. 23, 1993); *In re* Petition of Northern States Power Cos. Gas Util. for Auth. to Change its Schedule of Gas Rates for Retail Customers in Minnesota, 146 Pub. Util. Rep. 4th (PUR) 1 (Minn. Pub. Util. Comm'n 1993).

96. Washington Utils. & Transp. Comm'n v. Washington Natural Gas Co., 1993 Wash. UTC LEXIS 87 (Sept. 27, 1993); Iowa-Illinois Gas & Elec. Co., 1993 Ill. PUC LEXIS 245, at *111 (July 21, 1993).

97. Application of Wisconsin Gas Co., a Gas Pub. Util., to Increase Natural Gas Rates, 1993 Wisc. PUC LEXIS 68 (Nov. 11, 1993).

98. One survey concluded that most states appear to be taking a wait-and-see approach in considering the appropriate regulatory action to Order No. 636. *Survey of States Uncovers No Radical Effort to Reform LDC Regulations this Winter, but Ideas for Local Responses to FERC's Restructuring of Natural Gas Pipelines Are Being Explored*, FOSTER NAT. GAS REP., Feb. 10, 1994, at 12-20.

99. Many states allow gas utilities to file changes in the gas components of their rates on a periodic basis. This fuel clause adjustment addresses the cost recovery for gas purchases. The process of adjusting the gas cost recovery becomes more complex as the available alternatives expand. *In re* Regulation of the Purchased Gas Adjustment Clause Contained in the Rate Schedules of Murphy Gas, Inc., 1993 Ohio PUC LEXIS 888 (Sept. 30, 1993); *In re* National Fuel Gas Distribution Corp. for Waiver of Certain Provisions of Regulations, 1993 Pa. PUC LEXIS 96 (June 15, 1993).

service.[100] A second and more important issue is the rule structures and incentives that commissions will adopt in light of the less heavily regulated federal portion of gas sales.[101]

State commissions are only beginning to look at the long-term regulatory questions. The Massachusetts Department of Public Utilities issued one early decision on the treatment of changes in supply sources. In its decision, the Department concluded that it could not make wholesale changes in its approach to cost recovery, and it would not greatly change its level of review.[102] It adopted a two-phase approach. In the first phase, LDCs would seek approval of gas conversions. The conversions would need to be prudent and based on a comparison of available, market-offered replacement resources. Prior approval, however, would not assure the recovery of these gas costs. In the second phase, the Department would continue to review the utility's management of the resulting gas contracts. Because these contracts would provide the LDCs with the ability to adjust their actual purchases, the Department would continue to monitor those contracts approved in the first phase.

In contrast, the California Commission has embarked on a more aggressive use of incentive regulation of gas procurement. In one case, the Commission announced its intent to tie gas prices to futures prices (with some consideration given to other indices and some given to long-term stability).[103] To the extent there was any under- or over-recovery, the approach called for an even distribution of the gains or losses between shareholders and rate payers.[104]

As the Massachusetts and California opinions suggest, the real battles about the prudence of costs incurred by LDCs are beginning to take place. As the next round of requests for rate increases and purchased-gas adjustment-clause cases begin, the states will be forced to determine whether the LDCs are acting prudently within the new environment.

C. *Alternative Regulatory Responses to Order No. 636*

State commissions have several tools, such as prudence reviews and resource planning, with which to respond to the changes caused by Order No.

100. Indiana has taken tentative steps to deal with these costs. *See, e.g.*, *In re* Kokomo Gas & Fuel Co. for Approval of Gas Cost Adjustment, 1993 Ind. PUC LEXIS 228 (June 17, 1993); *In re* Northern Indiana Pub. Serv. Co. for Approval of Gas Cost Adjustment, Commodity Cost of Gas Adjustment, & Take-Or-Pay Surcharge Adjustment, 1993 Ind. PUC LEXIS 173 (Apr. 30, 1993).

101. *See, e.g.*, Gas Price Hedging, 151 Pub. Util. Rep. 4th (PUR) 58 (Iowa Util. Bd. Apr. 8, 1994).

102. *In re* Berkshire Gas Co., D.P.U. 93-187, 1994 WL 71304 (Mass. Dept. Pub. Util. Jan. 19, 1994).

103. Southern California Gas Co., 1994 Cal. PUC LEXIS 231 (Mar. 16, 1994).

104. *Id.* at *31-32.

636. Although it appears likely that there will be increased pressure to unbundle services at the local level,[105] deregulation of all gas service does not appear to be likely. Several factors point to the retention of some form of continued regulation. First, core residential service retains its natural-monopoly characteristics.[106] Second, there are some practical limits to fuel switching by larger customers.[107] Finally, there are some painful distributional effects associated with the Order that state regulators are unlikely to ignore.[108] As a result, LDCs will probably see continued regulation,[109] and some commentators suggest that the LDCs are likely to see increased levels of regulation in the short-term.[110]

As noted previously, some state commissions are already studying the problems that the Order has created.[111] Emerging out of these efforts, and numerous articles and conferences, is a consensus that regulation will move in one of several directions: toward modified prudence reviews, integrated resource planning, or incentive regulation.[112] Each has its own strengths and weaknesses when judged in light of the policy goals state regulators typically use to explain their actions with regard to an industry in transition.

1. *Regulatory Goals*

Although many criteria are used to measure the appropriateness of a regulatory approach,[113] three are predominant. First, the approach should make it possible for utilities to attract capital without extracting monopoly profits from customers.[114] Second, the regulation should have the distributional goal of making the product available to all who need or want it. In this regard, dividing the costs of services becomes important as commissions attempt to subsidize particular classes of users who may not be able to afford

105. *See supra* text accompanying notes 87-89.

106. *See supra* text accompanying notes 25-26.

107. Richard J. Pierce, Jr., *Intrastate Natural Gas Regulation: An Alternative Perspective*, 9 YALE J. ON REG. 407, 408-11 (1992).

108. The most obvious short-term effect is the recovery of several billion dollars in transition costs. This recovery will be followed by years of potential transfers effected by the adoption of straight-fixed variable rate making. *See supra* note 83 and accompanying text.

109. Cano, *supra* note 86, at 7.

110. Phillip S. Cross, *Major Issues Remain for States as Order 636 Arrives*, FORT., Nov. 1, 1993, at 58.

111. *See supra* notes 93-100 and accompanying text.

112. *Regulator: Residentials Will Be on the Short End of Order 636 Benefits*, INSIDE F.E.R.C., June 1, 1992, at 6 [hereinafter *Regulator*].

113. BONBRIGHT ET AL., *supra* note 34, at 92.

114. *Id.* at 101. This notion of price setting is composed of elements related to capital attraction, efficient production, and consumer rationing. *Id.* at 92-101. "All three of the functions of public utility rates (based on these rationales) are designed cooperatively to serve one common goal of rate-making policy: the provision of the community with adequate kinds and amounts of public utility service, produced in an economical manner." *Id.* at 101.

a service level or who have the political wherewithal to claim a preferred allocation.[115] Like the telephone industry, where there were significant consumer subsidies built into the system,[116] the changes in gas regulation present real threats of unbundling and bypass at the local level that threaten any subsidies in existence.[117] Finally, the costs of administering regulation should be reasonable; that is, there should be real benefits to enforcing a particular regulatory regime. It makes no sense to adopt a particular regime if it will not produce benefits—lower prices or lower costs of capital attraction—that outweigh the administrative costs. Thus, there is a practical limit to the amount of tinkering that a commission can and should attempt.[118]

Without doubt, there is tension among these goals. To the extent a subsidy exists in a currently approved pricing scheme, it cannot withstand the effects of alternative providers. The subsidy will be bid out of the system.[119] On the other hand, it is plainly unfair to allow fuel-switching customers to burden captive customers with the full fixed costs of service. Those core customers' contributions to fixed costs are a significant reason that fuel switching is available. Finally, it is impossible to assign rates a true cost of service and thus to manipulate the rates to their "efficient" levels.[120] There is no simple administrative answer to the problem.

Although no simple formula will relieve the conflict of regulatory goals, one solution might be to adopt only some of the goals.[121] Practically, however, no commission can take such an approach because of competing political concerns and the immediate short-term economic transfers that might

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115. *Id.* at 101-05.

116. *See* Alfred E. Kahn & William B. Shew, *Current Issues in Telecommunications Regulation: Pricing*, 4 YALE J. ON REG. 191, 194-95 (1987). Similar concerns arise over the transfers that will occur with the change to straight fixed-variable rate making.

117. *Regulator*, *supra* note 112, at 6 ("[T]he past practice often has been to adopt cost-allocation methods 'because they tend to favor the residential class. Such favoritism toward the residential class may not be possible in the future.'"); *see also* Larry Foster, *Debate on LDC Restructuring Long on Questions, Short on Answers*, INSIDE F.E.R.C., May 24, 1993, at 10.

118. The practical limit may be seen by examining the risk of LDC gas procurement error:

> It is evident that the risk for the LDC in buying too much or too little commodity gas and transportation capacity or paying too much for gas services always exists. No matter how strict the state oversight is, the risk of making "errors" in gas procurement cannot be totally eliminated. So the objective of state oversight is not to require the LDCs to develop a "perfect" gas procurement strategy but to eliminate any systematic and preventable "errors" or "distortions" that are attributable to the LDCs. In other words, the emphasis of the state commission's involvement should be to communicate clearly with the LDCs regarding their responsibility and flexibility in arranging gas supplies without the threat of later penalties arising from regulatory hindsight.

Duann, *supra* note 28, at 74-75.

119. *But see infra* text accompanying notes 200-01.

120. The problem is intractable because of the existence of common cost for firm and interruptible transportation and commodity service. There is no principled rule to allocate these costs to particular customers. Pierce, *supra* note 107, at 414.

121. Typical of that approach is Mark Fowler's controversial position on telephone deregulation. *See* Fowler et al., *supra* note 8.

occur.[122] Instead, there must be a balancing of the various interests. The point of accommodation may vary,[123] but it will always exist in some form or another. Because there is no right answer, some process must accommodate the various interests. The current popular ideas are prudence reviews, integrated resource planning, and incentive rate making.

2. *Prudence Reviews*

Historically, commission practice has been to judge utility costs through a retrospective prudence review.[124] In a prudence review, a commission analyzes a utility's management decisions to determine their reasonableness given the surrounding circumstances.[125] Many states use some form of prudence review.[126]

The strength of the prudence review is that it does not displace the management's ability to make decisions. In its most effective form, the review only examines whether the management decisions and related costs were reasonable under the circumstances.[127] The examination process itself has an important attribute:

> Reasonableness reviews reduce an important asymmetry of information that exists between a utility and its regulator . . . . [T]he PUC has enough time to get all the facts it needs to review the reasonableness of a gas utility's supply portfolio. Reasonableness reviews, although generally unpopular, have been effective in catching or preventing large errors made by LDC managers.[128]

As noted previously, it seems likely that utility commissions will continue to use prudence reviews as a means of assuring the public that its welfare is being safeguarded.[129]

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122. Order No 636 is remarkable in this regard given the large transfers involved in its implementation. *See supra* note 83. FERC faced the same kinds of conflicts and modified its introduction of straight fixed-variable rate making, offering small companies alternative rate schedules that broke from the efficiency arguments driving the rest of the order. Order No. 636-A, *supra* note 6, at 36,173 (rates for small customers subject to volumetric one-part rates).

123. The Illinois Commerce Commission is approaching regulation with a lighter hand, trying to keep "regulatory interference . . . to a minimum." Cano, *supra* note 86, at 7 (quoting Ruth Kretschmer, Illinois Commerce Commissioner, speaking at the April 1993 Conference sponsored by the National Association of Regulatory Utility Commissioners and the Department of Energy).

124. *See supra* notes 42-47 and accompanying text.

125. *See* Duann, *supra* note 28, at 76.

126. *Id.* at 75 (reporting 31 of 50 states have conducted such reviews).

127. *See infra* notes 130-133 and accompanying text.

128. CHARLES GOLDMAN ET AL., PRIMER ON GAS INTEGRATED RESOURCE PLANNING 71 (1993).

129. *Id.* at 71-72 ("[R]egulators will be reluctant to remove after-the-fact reasonableness reviews because their regulated utilities that have heretofore been protected and many [utilities] will not have a proven record of operating in competitive gas markets.").

There is a significant philosophical and doctrinal limitation on the traditional prudence review. Inherent in the determination that a capital item or an expense is too high is a rejection of the management decision to incur that cost. "If . . . consumers prove that utility management was imprudent . . . then imprudent management expenses will be excluded from [the expenses] component of the rate-making formula."[130] Such a determination shifts the cost to the utility's investors by moving it out of the revenue formula.[131] Thus the reasonableness assessment implies a standard of review of management decision making. The standard of review may vary, depending on the type of expense involved. In the case of expenses for which there is arm's length bargaining for the item or service, the commission normally gives great deference to management's choices because the market tends to force the price of the item to competitive levels. On the other hand, commissions will impose a higher level of review in the absence of such bargaining, as in the case of transactions with affiliated companies.[132] Even in those situations, however, the courts will require some deference to utility management. The commission must establish that there has been an abuse of discretion and must overcome a presumption of managerial good faith.[133] The problem is to determine the degree of deference that ought to be afforded to the utility's management.

The dichotomy between arm's length and affiliate transactions, however, does not appear to be particularly pertinent to the emerging state regulation of gas after Order No. 636. If one were to accept the dichotomy, the changes wrought by Order No. 636 would not appear to be significant. In an environment that is likely to be increasingly competitive, the utility's decisions would seem to be sacrosanct. Only in those instances in which an LDC was purchasing gas from a parent or sister company would the state commission apply a marginally higher level of scrutiny.

The application of the dichotomy is not quite so simple in the Order No. 636 environment. Additional factors must be considered in the prudence review. The Order creates a brand-new world for LDCs. The LDC is not a city-gate purchaser from a source whose prices have already been scrutinized. Their managers are now responsible for creating a portfolio of gas. These decisions bring new kinds of risks. Under these circumstances, it is not clear whether lower levels of review are warranted (given the market checks) or whether higher standards are more appropriate (given the greater levels of risk).

130. TOMAIN ET AL., *supra* note 44, at 166.
131. *Id.*
132. PHILLIPS, *supra* note 2, at 245.
133. *Id.* at 246.

Prudence reviews also come with significant costs. First, the process is administratively expensive for both the LDC and the commission. "A prudence review is typically an elaborate and involved process because the state commissions and the LDCs need to reconstruct the market environment upon which the procurement decisions were made initially. It can be a huge undertaking even under the best of circumstances."[134] Moreover, as Duann notes, the complexity of the review process can only increase as the number of potential procurement decisions increases with the deregulation of commodity pricing and interstate transportation.[135]

Second, the review process may encourage uneconomic choices in both directions. On the one hand, the utility may be too aggressive and lock into short-term contracts to lower prices and thereby increase the risk of a supply disruption.[136] On the other hand, the LDC may fear supply disruption so much that it locks in useless long-term contracts and thereby exposes customers to unnecessarily high gas prices for long-term supplies.[137] In either case, the risk of an unfavorable prudence audit would adversely affect the supply mix.[138]

Finally, there is no positive benefit from being aggressive in the traditional prudence review. Because gas costs are an expense, there is a rough dollar for dollar recovery, and the utility gains no particular advantage from an effective cost strategy.

> [A]ll cost savings from a more efficient fuel portfolio are passed through to ratepayers, if not immediately, then within a short period. Without some positive benefit, utilities will tend to be more passive and cautious in fuel procurement, emphasizing stable (read static) and reliable fuel sources over less costly alternatives, whose substantial price discount may more than offset any disadvantage from lower reliability.[139]

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134. Duann, *supra* note 27, at 76.

135. *Id.* at 76-77.

136. Stephen A. Furbacher, PUC Review of Supply Management, *in* RECORD OF PROCEEDINGS: CONFERENCE ON NATURAL GAS USE, STATE REGULATION AND MARKET DYNAMICS IN THE POST 636/ENERGY POLICY ACT ERA 119 (Apr. 26-28, 1993); Craig S. Cano, *Unbundling at LDC Level Will Feature New Set of Problems, NARUC Told*, INSIDE F.E.R.C., Aug. 3, 1992, at 13.

137. *Increased Risk, supra* note 10, at 1 (recognizing both sides of the trade-off).

138. A similar problem exists in the regulation of electric utilities. *In re* Revision & Promulgation of Rules for Long-Term Forecast Reports & Integrated Resource Plans of Elec. Light Cos., 1989 Ohio PUC LEXIS 1306, at *5 (Dec. 19, 1989) (order denying rehearing).

139. Robert E. Burns & Mark Eifert, Designing Purchased Gas Adjustment Clauses to Provide for Incentive Compatibility in a More Competitive Environment, *in* RECORD OF PROCEEDINGS: CONFERENCE ON NATURAL GAS USE, STATE REGULATION AND MARKET DYNAMICS IN THE POST 636/ENERGY POLICY ACT ERA 543 (Apr. 26-28, 1993). For a similar suggestion, see *Local Distribution Company Post-Restructuring Issues Are Identified in GAO Report Appendices*, FOSTER NAT. GAS REP., Nov. 18, 1993, at 20.

Part and parcel of this conservatism is the element of regulatory risk itself. "Some analysts have argued that LDCs, in an environment of intense prudence reviews, begin to purchase gas not to meet the overriding goals of reliability, cost, and cost stability, but rather purchase gas in ways defensible in a reasonableness review."[140] Taken together, the effects of the regulatory system itself tend to be at odds with each other. It is not remarkable, therefore, that there have been calls for a modified definition of prudence in the new regulatory environment created by Order No. 636.[141]

3. *Integrated Resource Planning*

In response to the problems of prudence reviews and to changing regulatory approaches in general, support has grown for prospective reviews of utility purchasing.[142] While such planning is in its infancy for gas utilities,[143] it has been part of electric utility regulation for several years.[144] One estimate suggests that more than thirty states have some form of planning process in place.[145] Moreover, the National Energy Policy Act mandates at least the consideration of such an approach for gas utilities by the end of 1994.[146] States are beginning formal processes to address that mandate.[147]

Integrated resource planning (IRP) involves utility management and state commissions in a process of prospectively determining what mix of supply and demand options will produce reliable service at the lowest cost.[148] Generally,

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140. GOLDMAN ET AL., *supra* note 128, at 71.

141. Craig S. Cano, *Winter of Our Discontent? Cautiously, Gas Industry Officials Say No*, INSIDE F.E.R.C., Nov. 22, 1993, at 11.

142. Larry Foster, *Debate on LDC Restructuring Long on Questions, Short on Answers*, INSIDE F.E.R.C., May 24, 1993, at 10; *NGSA Issues Checklist to Help PUCs Implement Order No. 636*, FOSTER NAT. GAS REP., Dec. 30, 1993, at 4; John Simpson & Lori Burkhart, *Industry, Regulators Share Visions for Natural Gas*, FORT., June 1, 1993, at 10.

143. GOLDMAN ET AL., *supra* note 128, at 3.

144. Ohio, for example, has had rules for electric utility IRP in place since 1989. *See In re* Revision & Promulgation of Rules for Long-Term Forecast Reports & Integrated Resource Plans of Elec. Light Cos., 1989 Ohio PUC LEXIS 1144 (Oct. 31, 1989).

145. Leonard V. Parent, *If It Isn't One Thing, It's Another; Integrated Resource Planning; Pipe Line Progress*, PIPE LINE INDUSTRY, Feb. 1993, at 13.

146. Energy Policy Act of 1992, Pub. L. No. 102-486, § 115, 106 Stat. 2776, 2803 (1992); *see* Donald F. Santa, Jr. & Patricia J. Beneke, *Federal Natural Gas Policy and the Energy Policy Act of 1992*, 14 ENERGY L.J. 1, 23-24 (1993) (discussing legislative history).

147. *In re* Investigation into Standards Regarding the Encouragement of Inv. in Conservation & Energy Efficiency by Gas Utils. Under Section 115 of the Energy Policy Act of 1992, 1993 Minn. PUC LEXIS 176 (Nov. 8, 1993); Rulemaking to Consider the Comm'n's Compliance with the Energy Policy Act of 1992, 1993 Cal. PUC LEXIS 484 (June 3, 1993).

148. GOLDMAN ET AL., *supra* note 128, at 3 ("IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost."); *NARUC Studies Integrated Resource Planning*, FOSTER NAT. GAS REP., Jan. 20, 1994, at 13 ("IRP may take either a formal regulatory path or may become a set of processes overlaid upon existing business and regulatory practices.") (discussing GOLDMAN, *supra*

the regulatory process will require the LDC to prepare and present an integrated resource plan that explicitly considers supply and demand options. Public participation and either commission review or approval of the plan will follow.[149]

Like prudence reviews, integrated resource planning has strengths and weaknesses. The primary benefits come from the expectation of better resource planning.

> An integrated resource planning process can help facilitate a systematic approach for utility managers to evaluate diverse business activities and potential investments . . . . Gas utilities will increasingly have to offer innovative services to diverse customer groups with varying needs . . . . After completing a strategic planning process, the utility is in a much better position to explain its decision-making and resource procurement process, whether or not it is required to do so by a regulatory commission.[150]

In addition, integrated resource planning would likely reduce the regulatory risk of disallowance that a utility would face without the plan in hand.[151] The assumption is that if the utility commission approves the supply structure of the utility at the outset, it would be less likely to attempt to second guess a LDC.[152]

These benefits, however, come with some likely costs.[153] Most problematic is stagnation which could result from integrated resource planning.

> A utility with a commission-approved least or best cost fuel procurement plan is unlikely to deviate greatly from that plan since any deviation places them [sic] at risk of a prudence disallowance. Instead of taking advantage of price differentials among various fuel

note 128, from which definition in text was drawn); *see also* Cano, *supra* note 86, at 7 (comments by Adam Jaffe).

149. GOLDMAN ET AL., *supra* note 128, at 25.

150. *Id.* at 26-28.

151. *Id.* at 28-29. The Ohio commission conceded as much when it adopted its rules for electric company integrated resource planning. *In re* Revision & Promulgation of Rules for Long-Term Forecast Reports & Integrated Resource Plans of Electric Light Cos., 1989 Ohio PUC LEXIS 1144, at *7 (Oct. 31, 1989) ("[S]ubjectivity in the retrospective analysis of the prudence of management activities will be minimized by the development of a comprehensive record in forecast evaluation proceedings.").

In addition to better planning and decreased regulatory risk, the report prepared for the National Association of Regulatory Commissions listed as additional benefits: (1) better penetration of end-use options for high efficiency products, (2) public participation in resource planning, and (3) coordination of energy and environmental planning. GOLDMAN ET AL., *supra* note 128, at 29-30.

152. Pierce, *supra* note 31, at 51.

153. *See* GOLDMAN ET AL., *supra* note 128, at 31-32 (forecasting high administrative costs versus low expected benefits, incompatibility with competitive sourcing, and capture of most benefits in building standards).

> markets (for example, gas futures, spot gas, short-term gas, or long-term gas), fuel managers tend to stand firm. The ex-ante fuel procurement review tends to substitute for legitimate managerial prerogatives as the utility adheres to the fuel portfolio approved in the ex ante plan.[154]

A variation of this problem is the lack of flexibility that the plan may imply.[155] Also, the gains associated with integrated resource planning will not be significant because the practical implications of demand-side management, such as introducing high efficiency water heaters, are not great.[156] Finally, integrated resource planning has the potential to involve high administrative costs.[157] This problem would be particularly visible in early periods of implementation as the companies, the public, and the commissions struggle to determine the unclear definitions associated with integrated resource planning.[158]

Integrated resource planning has some obvious appeal, but shares many of the same problems as prudence reviews. On the one hand, both the commissions and the public would obtain at least a view of the planning process, and access would benefit the company, at least to the extent of

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154. Burns & Eifert, *supra* note 139, at 543.

155. As Duann points out:

> The main disadvantage of the prior-review approach is that the procurement plan may be developed and agreed on far ahead of time and the gas market conditions may have changedconsiderably. By the time the procurement plan is implemented, it is clearly a less desirable plan. Since the LDC's gas procurement decisions will still be evaluated based upon the agreed-upon plan, the LDC will have little incentive to make the necessary adjustments, knowing it will not be penalized for not changing the procurement plan. The implied fixity of an agreed gas procurement plan appears to be counterproductive.

Duann, *supra* note 28, at 78.

156. As Goldman, et al. elaborate:

> Avoided electricity costs often tend to be higher than gas avoided costs when adjusted for equivalent energy service provided. However, it is not that easy to directly compare avoided electric and gas costs because of differences in costing methods and conventions, end-use conversion efficiencies, and operational characteristics of electric and gas utilities. Despite that caveat, avoided gas costs that are lower than avoided electric costs for DSM suggest that: (1) it will be relatively more difficult for gas energy efficiency programs to pass cost-effectiveness tests compared to electric DSM programs, and (2) all else being equal, net DSM program benefits might be smaller.

GOLDMAN ET AL., *supra* note 128, at 20-21 (citations omitted); *see also* David Dodson, *Impact of SFV Rates, Transition Costs Overstated, Analysts Argue*, INSIDE F.E.R.C., Nov. 29, 1993, at 11.

157. GOLDMAN ET AL., *supra* note 128, at 31.

158. Parent more fully describes this problem of variation between IRPs of different locations:

> IRPs are supposed to take into consideration the costs to society of environmental degradation that are not currently reflected in the price paid for energy at the burner tip or the point-of-use. But the manner of consideration varies widely from state to state, from commission to commission.

Parent, *supra* note 145, at 13. The Ohio commission conceded the difficulty of the problem in its order adopting IRP for electric companies. *In re* Revision & Promulgation of Rules for Long-term Forecast Reports & Integrated Resource Plans of Elec. Light Cos., 1989 Ohio PUC LEXIS 1144, at *9-10 (Oct. 31, 1989) (defining least cost alternatives).

reducing regulatory risk. On the other hand, these benefits may not translate into any real financial gains that could not otherwise be obtained by the gas industry through less expensive alternatives such as building codes. Indeed, the benefits may well result in lost opportunities for cost savings through purchasing.

A proposal by Adam Jaffe and Joseph Kalt takes the interesting alternative approach of providing gas purchase planning.[159] The Jaffe-Kalt method is clearly not a full process of integrated resource planning because it does not adjust for demand-side management. Instead, it looks only at the mix of gas options. "Pre-approval policies would require a gas . . . utility to justify the composition of its acquisition portfolio before the PUC, much the same way that IRP [Integrated Resource Planning] policies now require utilities to justify the extent of their reliance on Demand-Side Management . . . and so forth."[160] The process would provide a range of options with which the utility could work with some assurance of regulatory approval.[161]

The approach has two potential advantages. First, it avoids the problem of trying to determine avoided gas costs, a process that appears to have little likelihood of success. Second, it provides the utility with some assurance that its plan, if followed, will result in prudent, and therefore recoverable, expenditures.

4. *Incentive Regulation*

In reaction to the limits of both pre- and post-review of costs in traditional regulation, a growing number of scholars, regulators, and regulated entities argue for some form of incentive regulation. The primary justification for such a change is the information asymmetry that exists between utilities and state commissions. Without a clear sense of how various costs of service fit together, commissions arguably will fail to provide the right cost signals to utilities and their customers.[162] As a counterbalance to information asymmetries, regulators can attempt to insert incentives in elements of the traditional rate structure or totally divorce prices from costs.

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159. Adam B. Jaffe & Joseph P. Kalt, *Oversight of Regulated Utilities' Fuel Supply Contracts: Achieving Maximum Benefit from Competitive Natural Gas and Emission Allowance Markets*, *in* RECORD OF PROCEEDINGS: CONFERENCE ON NATURAL GAS USE, STATE REGULATION AND MARKET DYNAMICS IN THE POST 636/ENERGY POLICY ACT ERA 121, 123 (Apr. 26-28, 1993) (on file with author) [hereinafter Jaffe & Kalt, *Oversight of Regulated Utilities*]; *see also* Adam B. Jaffe & Joseph P. Kalt, *Insight on Oversight*, FORT., Apr. 15, 1994, at 23, 24-25.

160. Jaffe & Kalt, *Oversight of Regulated Utilities*, *supra* note 159, at 123.

161. *Id.* Another interesting aspect of the Jaffe-Kalt approach is the use of competitive bidding to fill gas contracts. *Id.* at 123-24.

162. Duann, *supra* note 28 at 80; Mohammad Harunuzzaman et al., *Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure*, 91-19 NAT'L REG. RES. INST. 46 (1991).

a. *Incremental Approaches*

Two common ways of providing incentives involve allowing the utility to retain cost savings or to add additional returns for desired behavior. For example, the commission might set a target rate for gas expenses. If the utility beats that goal, it keeps or shares the benefits of the lower cost. If the utility misses the goal, it absorbs or shares the loss.[163] In this way, the utility's management has an incentive that is consistent with the customers' welfare interest.

One difficulty with such an approach arises in the setting of target prices.[164] One logical construct would use the spot price of gas. Since the spot price represents the current market-clearing price of gas, it is, arguably, the proper measure of value that the utility should be seeking to attain.[165] Regulators, however, are likely to balk at setting prices based on contracts that require only best-efforts production with thirty-day limits.[166] Moreover, price is more volatile than it would be under longer-term agreements.[167] While these short term contracts may be an economic solution, they may not provide the political cover regulators desire.

Another problem with basing incentives on expenses is that it creates problems in calculating the allowable rate of return for the regulated portion of the utility. In the basic formula, rate of return is tied to the rate base, not expenses, and the utility is allowed only a rate of return on rate base. The effect of an incentive structure tied to expenses is that it leverages the rate of return. The extent of the leverage would depend on the ratio of expenses to allowed rate of return and the accuracy of the expense predictions used to set

163. For an application of this approach, see Harunuzzaman et al., *supra* note 162, at 54-65 and Burns & Eifert, *supra* note 139, at 543-45. A detailed discussion of the target-rule proposal is contained in Robert E. Burns et al., *Current PGA and FAC Practices: Implications for Rate making in Competitive Markets*, 91-13 NAT'L REG. RES. INST. 175-221 (1991).

164. Duann, *supra* note 28, at 82.

165. For an interesting discussion of this point, see Hatcher & Tussing, *supra* note 23, at 21-32. Like Burns and Eifert, they propose a benefit-splitting approach, but their base is tied to a weighted average of spot-market prices. *Id.* at 29.

166. A fine explanation of why regulators will likely hesitate to use only best-efforts production with thirty day limits is explained by Harunuzzaman et al.:

> It may not be economically optimal to minimize either long-term contract costs or spot-purchase costs individually. This is because the optimal mix depends on demand parameters such as peak demand and annual volume demand, and supply parameters such as the maximum delivery per day each firm supplier can guarantee and the total volume each spot supplier is able to deliver.

Harunuzzaman et al., *supra* note 162, at 55. There would appear to be less legal protection against breach as well. Richelle, *supra* note 31, at 666, 676. Hatcher and Tussing, however, point out that spot markets have been more successful in recent years in covering for firm contract shortfall during periods of peak demand. Hatcher & Tussing, *supra* note 23, at 27 n.21.

167. In a discussion of the spot market, Richelle notes that reported spot-market prices moved from $.95/Mcf to $2.65/Mcf between February and September 1992. Richelle, *supra* note 31, at 662-63. The days of the twenty year contract and its accompanying inefficiencies, however, appear to be gone.

the gas component of retail rate to customers. In any case, rate of return could be greatly exaggerated or injured by the use of an incentive built into expenses.[168]

In theory, this leverage problem could be solved by allocating the amount of the savings or loss between the company and its customers. For example, the company and its customers might share equally any loss or gain around the target price for gas.[169] This theory, however, is extraordinarily difficult to apply in practice. Setting the appropriate sharing ratio is hardly a science. Rather, it will reflect a political judgment about the particular level of risk each of the relevant parties should absorb in the newly defined market for natural gas.[170]

As a second alternative, the commission might vary the rate of return based on performance.[171] For example, some states have tied the basis points for return on equity to the performance levels of power plants.[172] The clear advantage is the mechanism's simplicity. Once the standards are set, the commission and utility can mechanically calculate the allowable return.[173] It is not clear, however, that there is any marginal advantage to adopting such a scheme over even simpler options available to the commission.

> [I]t can be argued that under flexible rate-of-return pricing the cost-control incentive will not be that much different from the incentive effects of regulatory lag under the traditional rate-of-return regulation. This approach also has apparently no direct effect in adding flexibility for pricing core-distribution service. It is a somewhat compromising approach which may be viewed as a trans-

168. Walker explains:

> Disallowances of gas costs can easily wipe out an LDC's earnings. A review of 1992 fiscal results for the 53-company C.A. Turner Distribution and Integrated Natural Gas Group demonstrates this point. Sixty percent of the group's revenues were gas costs ($16.6 billion), while income available for common equity was $1.5 billion. A 9-percent disallowance of gas costs would nearly erase the group's earnings. Conversely, if allowed to keep or share an equal percentage, its earnings would increase dramatically.

Harold Walker III, *Managing Gas Supply Risk*, FORT., Mar. 1, 1994, at 39.

169. For an example of the approach using a sharing mechanism, see Harunuzzaman et al., *supra* note 162, at 63-64.

170. *Id.* It is also important to note that expense-based incentive programs have been attacked because they have been of limited success. PHILLIPS, *supra* note 2, at 564 n.156 (citing Eric J. Schneidewind & Bruce A. Campbell, *Michigan Incentive Regulation: The Next Step*, *in* CHALLENGES FOR PUBLIC UTILITY REGULATION IN THE 1980s 407 (Harry M. Trebing ed., 1981)).

171. *See generally* Harunuzzaman et al., *supra* note 162, at 77-79.

172. PHILLIPS, *supra* note 2, at 535-36.

173. Duann, *supra* note 28, at 84-85.

ition from the current cost-based regulation to a more "direct" incentive regulation.[174]

In short, it may be tinkering without any real purpose.

b. *Price Caps*

In response to the problems associated with incremental changes, a more radical demand for price caps sometimes emerges. This form of incentive regulation seeks to separate pricing from costs by setting a ceiling price and allowing the utility to retain or share the earned profits.[175]

> Under pure [price cap regulation], the earnings of a regulated company are divorced entirely from both its realized production costs and its investment decisions. Maximum average price levels (price caps) are specified in advance and remain unaltered as the magnitude of the company's realized production costs change or its investment patterns and performance vary. In this respect, the company bears the full financial implications of its actions.[176]

After a rate hearing of some sort, the incentive rates permitted for particular services would permit the company to recover its costs as initially established. In subsequent periods, the approach would permit increases in rates for exogenous factors such as inflation and taxes. Yet it would encourage the utility to reduce costs by accounting for and offsetting costs against expected increases in productivity.[177]

There may be several benefits from this form of regulation. First, because every dollar saved is profit for the utility, it creates incentives for utilities to cut costs.[178] This incentive would be consistent with the effects of Order No. 636's requirement of access to competitive gas markets. Second, it avoids

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174. *Id.* at 85.

175. Harunuzzaman et al., *supra* note 162, at 46-47.

176. David E.M. Sappington & Dennis L. Weisman, *Designing Superior Incentive Regulation: Accounting for All of the Incentives All of the Time*, FORT., Feb. 15, 1994, at 13.

177. For examples of price caps in telecommunications, see Policy & Rules Concerning Rates for Dominant Carriers, 54 Fed. Reg. 19,836 (1989); *In re* Alternative Regulatory Frameworks for Local Exchange Carriers, 107 Pub. Util. Rep. 4th (PUR) 1 (Cal. Pub. Util. Comm'n 1989). For a more complete description of the federal scheme, see Frank P. Darr, *Deregulation of Telephone Services in Ohio*, 24 AKRON L. REV. 229, 258-61 (1990); Sutapa Ghosh, *The Future of FCC Dominant Carrier Regulation: The Price Caps Scheme*, 41 FED. COMM. L.J. 401 (1989). Caps have also been used by other national authorities outside the United States. Alexander J. Black, *Responsible Regulation: Incentive Rates for Natural Gas Pipelines*, 28 TULSA L.J. 349, 375 (1993) (describing Great Britain's regulation of British Telecom).

178. Duann, *supra* note 28, at 83-84; Hyde M. Merrill, *Interutility Electricity Pricing: Theory vs. How to Do It*, FORT., Jan. 15, 1994, at 19-20.

exposing customers to monopoly rates. The cap prevents that form of expropriation.[179] Finally, administrative costs could be reduced.[180]

Each of these strengths, however, has an elemental problem. First, it is not clear that the incentives would have the intended effects on behavior. Because any really successful program will result in additional state scrutiny to adjust rates to a proper level that does not result in too much return, there is a counter-incentive to take small steps.[181] Second, a successful program may encourage a diminution in the quality of service as the company cuts costs to improve its return under price caps.[182] In the newly deregulated gas market, this change might translate into either inefficient long-term contracts or uncertain short-term arrangements. Third, even though the second argument in favor of caps—that caps avoid gouging—is premised on the belief that the state commission can properly set the rates, the escalators, and the offset, "[t]here are complex problems to be resolved in the implementation of any price-cap regulation. These problems include the selection of the initial price cap, the adjustment indices, the types of services covered, and the period for reconciliation."[183] These problems are especially apparent during periods of price instability.[184] The process of setting and monitoring these sorts of rates is just as complicated as a full-blown rate case,[185] and the public relations problems for a commission that permits a rate that turns out to be too high may be even worse.[186] Thus, while price caps may seem to get the incentives right at one level, the counter-incentives and administrative problems present significant reasons to reject that approach.

III. Dealing with the Future: A Combination Approach

The foregoing discussion of the various ways a commission might pursue the goals of low-cost and efficient administration indicates that no single regulatory or market scheme is a panacea. Rather, each alternative has benefits and costs. The real solution lies in finding the balance of tools and markets

179. The company's initial rates will be set to recover its existing costs, including reasonable expenses. However, the plans would require periodic true-ups to insure that the program would continue to work in subsequent periods.

180. Harunazzunman, *supra* note 162, at 66 ("One perception is that price caps would spread out the number of rate reviews over time, with the different stakeholders expending less resources as a consequence.").

181. *See* Sappington & Weisman, *supra* note 176, at 14-15 (discussing the problem of recontracting by state commissions).

182. Merrill, *supra* note 178, at 21.

183. Duann, *supra* note 28, at 83.

184. Harunuzzaman et al., *supra* note 162, at 91.

185. Merrill, *supra* note 178, at 21.

186. *Id.* at 84. A related concern is that regulators will reject the approach as being inconsistent with their understanding of regulation. Black, *supra* note 177, at 390.

that best accomplishes those goals at a particular time when the rules are changing and utilities, commissions, and customers are apprehensive.

A. *Some Reasonable Assumptions*

The proposal that follows is premised on the general goals of utility regulation: avoidance of monopoly pricing; sensitivity to distributional issues; and recognition of administrative costs.[187] Additionally, the proposal rests on several assumptions.

First, reliance on a single regulatory tool or the market is not a workable solution. The various tools, ex ante or post hoc reviews or particular types of incentive regulation, all have inherent problems that make each one standing alone insufficient. In addition, markets are inappropriate remedies because the large core residential customer base is bound to the LDC in what currently appears to be a natural-monopoly relationship. The solution, then, may lie in some combination that draws on providing market-like incentives within the framework of limited regulation.

Second, administrative costs will not be determinative, although the costs may lead to limitations at the margins. Commissions can be expected to continue regulating for the reasons suggested previously.[188] They will continue to use a set of tools, and those tools are costly. Indeed, there is every reason to believe that initially commissions will feel a need to exert more effort just to fill the informational void created by the new rules set out in Order No. 636. While administrative cost at the margins will be important, and the commissions should attempt to adopt a cost-effective mix of tools, deregulation at the federal level will not translate into reduced administrative costs at the state level. In the short term, the opposite is likely to be the case.

Third, commissions will require companies to adopt some sort of mix of long-term, short-term, and spot purchases to satisfy core customer requirements. Although there are arguments to the contrary (and the California commission is experimenting with other alternatives based on spot prices),[189] it seems unlikely that commissions ex ante will find it acceptable for a gas utility to guarantee service on thirty-day spot-market contracts.

Fourth, utility commission will seek to balance monopoly pricing concerns against loss of high-load customers to minimize underuse of facilities (stranded costs) through wider use of transportation programs. Commissions will attempt to keep high-load customers in the system in order to spread demand-related costs. The trade-off for gas utilities is that these high-load customers may be required to absorb more than the incremental price of transportation. That is,

187. *See supra* Part II.C.1.
188. *See supra* notes 33-34 and accompanying text.
189. *See supra* note 113.

these customers will pay transportation rates that will include costs that might be identified as demand costs that are usually only assignable to firm transportation and commodity customers.

Finally, there are some transaction costs in leaving the LDC and contracting for gas supplies and transportation. These costs include one-time payments required to make a new connection, and the ongoing costs of contracting for gas supplies and transportation. These costs create some cushion in setting transportation rates.

B. *A Transitional Approach to Gas Acquisition Reviews*

Based on the assumptions set out above, regulation should consist of ex ante planning, incentive rate setting, and post hoc reconciliation.[190] Although administrative costs are potentially high, this approach would tend to lower the uncertainty of review and encourage entry into new markets.

In practice, a commission would establish guidelines to determine the acceptable range of risk represented by varying mixes of spot, short-term, and long-term gas contracts. The commission would then set a target range or dead band of costs for gas. Within that dead band, the commission would estimate gas cost, and set that as the cost of gas to be recovered in rates. The utility could fill its gas needs in the market through whatever means it chooses.

Periodically, annually or semi-annually, the commission would review the rates to determine if the range has been properly set, if the company is making prudent purchasing decisions, and if the company is continuing to earn a reasonable rate of return. During this review, the gas costs would be reviewed to determine compliance with the resource plan. If the utility is within the dead band, there would be no adjustment. If its gas costs are below projected levels, and the company did not unreasonably subject the core customers to unnecessary price risks, it would retain all or a part of the customer receipts, subject to any sharing mechanism the commission might establish. If the utility's gas costs are above the projected levels, and the company did not purchase gas at unreasonably high rates, it would recover none or a portion of the underpayment from customers, subject to any sharing mechanism the commission might establish.

Because there is a potential for major swings in recovery, the commission would also need to review the rate of return to determine if the company was continuing to earn a reasonable return on rate base. To the extent that the company was over-earning or under-earning, there might be a need to adjust

190. What follows draws heavily on the literature concerning incentive regulation of gas utilities, in particular the work of Burns & Eifert, Harunuzzaman et al., and Jaffe & Kalt. *See supra* notes Part II.C.2-C.4.a. The attempt here is to draw the strengths of the various approaches together while elimnating as many of the weaknesses as possible.

the formulas used to set gas expenses, to review the distribution between customers and the utility of benefits and losses due to purchasing, or to consider initiating a full review of rates.

For example, assume that a utility needs 200,000 units of gas for customers. It might fill that need through various combinations of contracts. Further assume that through a gas purchase planning hearing, the commission determines that the appropriate range of contracts is between a combination of 30% spot, 30% short-term, and 40% long-term (30-30-40), and a combination of 20% spot, 30% short-term, and 50% long-term (20-30-50). If average prices for these types of contracts at the time of the finding are $1.90, $2.00, and $3.00, then the dead band of rates would be $2.37 to $2.48.[191] Assume the commission sets the price for billing at the midpoint of the range. If the utility's gas costs are within the dead band, there is no disallowance of or additional recovery. If the gas costs are lower than $2.37, the utility would either retain or partially retain receipts based on the average price. In that case, however, the commission would determine whether the company incurred an unreasonable amount of risk. If the gas utility did not incur unreasonable risks, the commission should allow the pass through of receipts to the utility to continue. For the next period, however, the commission might want to consider making an adjustment to the formula for calculating the dead band.[192] If the gas cost savings are attributable to a different mix of contracts, the commission should consider revising the formula to reflect more

191. The calculations are set out below:

	Spot *(%)* *(Tot)* *(SP)*	Short *(%)* *(Tot)* *(ShP)*	Long *(%)* *(Tot)* *(LP)*	Total Cost	Ave. Cost *TC/ Tot*
High Risk	$114,000 *(.3)* *(200,000)* *($1.90)*	$120,000 *(.3)* *(200,000)* *($2.00)*	$240,000 *(.4)* *(200,000)* *($3.00)*	$474,000	$2.37
Low Risk	$76,000 *(.2)* *(200,000)* *(1.90)*	$120,000 *(.3)* *(200,000)* *($2.00)*	$300,000 *(.5)* *(200,000)* *($3.00)*	$496,000	$2.48

The figure in each block indicates the percentage of that particular component assigned by the commission. To calculate properly the weighted average of the total, the component totals are calculated, summed (TC), and divided by the total number of units.

192. Under this circumstance, the recalculation should only occur if there were an expectation of continued low rates.

clearly the market risks that appear reasonable under changing circumstances. If the utility acted unreasonably in incurring the savings, then the response should be a full or total refund of the savings to customers.[193]

If the gas costs exceed those projected by the dead band, the utility would be liable for all or part of the excess costs. If the utility was reasonable in incurring these costs, then the predetermined recovery mechanism should be applied. As in the prior example, the commission should determine whether the preexisting price assumptions and mix ratios should be adjusted. If the commission determines that the overage is the result of imprudent behavior, however, then the loss should fall on the utility.

This proposal meets the criteria for setting the incentives in a manner that is consistent for both sides of the transaction. The utility has an opportunity to take advantage of the marketplace and retain some of the benefits of its managerial efforts. The commission will not have to bailout the utility for its mistakes or foreclose the possibility that existing practices cannot be improved and then passed through to customers. The proposal will encourage least-cost purchasing and simultaneously assure the commission that the utility is not taking advantage of the risk presented by some forms of incentive regulation.

It is unclear, however, whether this incentive form of regulation has the ability to avoid the problems and disincentives associated with a commission's reversal. Part of the problem may be avoided by adding a requirement that the utility competitively bid its requirements under the formula.[194] Bidding might have the effect of assuring regulators that the gas purchases made were the best available for a given level of reliability. Thus, the regulators would have less incentive to reverse or recontract prior determinations. Formal auctions, however, carry their own costs, and it is not clear that the costs are justified.[195] If the incentives cannot be built into the process by some sort of external factor, then it will fall on the state commission to regulate in good faith and avoid the recontracting problems on its own initiative.

A second problem is that commission review will require substantial administrative resources. To create confidence in the end product, the commission will be reviewing a broader range of purchasing activities. Despite increased administrative costs and resources, the apparent trend in regulation points in this direction. The alternatives to setting core customer rates—increased prudence reviews, price caps, or deregulation—are not

193. To the extent that the utility stayed within the ranges and took advantage of lower prices, those lower prices should be reflected in the new calculation of the dead band. This aspect of the proposal is problematic since it creates an incentive for the commission to disallow costs. Commissions have often been attacked for their abuse of this power. Richard J. Pierce, Jr., *Public Utility Regulatory Takings: Should the Judiciary Attempt to Police the Political Institutions?*, 77 GEO. L.J. 2031, 2047-53 (1989).

194. Jaffe & Kalt, *Oversight of Regulated Utilities*, *supra* note 160, at 123-24 (proposing mandating LDCs to seek competitive bids for gas resources).

195. Electronic bulletin board systems may be one way to reduce auction costs.

particularly palatable. Moreover, to the extent that the proposed formula works, the review process would be simplified over time as the informational problems decrease with experience. More importantly, the proposal looks at gas costs, the most significant and variable item in the customer bill.[196] It logically follows that the commission should focus its resources on assuring itself and the public that the utility is making reasonable efforts to address the new marketplace and take advantage of available benefits.

C. *The Problem of Bypass*

The commission will face both renewed claims of bypass and the need to address transportation access and rates. Some level of unbundling would appear to be a foregone conclusion. The marketplace requires a response that includes transportation.[197] Most states already permit such inclusion and Order No. 636 will further encourage such actions on the part of customers that have the means to purchase gas. The real debate will be on setting transportation rates that will allow LDCs to retain some of the load. That debate will turn on whether the transportation rate should include a portion of the system's fixed costs for what would appear to be interruptible service. As more costs are included, the transportation rate will tend to encourage bypass; as rates are lowered, the utility will face an ever tighter cost squeeze that will have to be made up somewhere else.[198]

Although it is clear that price discrimination cannot be sustained,[199] it is not self-evident that all fuel-switching customers will leave the system in significant numbers[200] or that the core customers absorb all of the costs of bypass.[201] One element that is seldom included in the calculation, however, is the transaction costs that a transporter must incur to leave the system.[202] First, there is the cost of leaving the system and making any necessary new connections to a pipeline. Second, and more important, are the costs of contracting for a predictable level of service. The transporter either will have to develop that expertise internally or contract for it. Recognition of this cost may give commissions some room to shift costs in the short term to those high-

196. Harunuzzaman et al., *supra* note 162, at 55.

197. Broadman & Kalt, *supra* note 26, at 201.

198. MacAvoy et al., *supra* note 27, at 227, 236.

199. John R. Meyer & William B. Tye, *Toward Achieving Workable Competition in Industries Undergoing a Transition to Deregulation: A Contractual Equilibrium Approach*, 5 YALE J. ON REG. 273, 286 & n.46 (1988).

200. *See Over Half of Northwest Natural Gas' Transporters Return to Sales Service*, INDUS. ENERGY BULL., Feb. 3, 1994, at 3 (Northwest Natural Gas, an LDC, reported that many customers are returning to the LDC because of difficulties associated with contracting gas supplies and transportation.).

201. Broadman & Kalt, *supra* note 26, at 203.

202. Pierce, *supra* note 107, at 409-11.

load customers who do not perceive that they benefit marginally from open transportation. Again, however, this shift is probably only temporary.

Conclusion

As long as there is a core customer base that has only one provider for its gas service, there will not be an ideal solution to the regulation of natural gas distribution. The last segment of distribution will remain essentially monopolistic and price regulation of some sort will continue. The problem for regulators and utilities, however, is that some other portions of the market are competitive. Thus, the utility faces real challenges to its ability to earn a return on existing assets, and utility commissions lose the ability to stratify the market and shift costs to protect residential and other high-priority customers who cannot move to alternative services. Both planning and incentives offer some relief. Planning involves the commissions in the choices utilities will make. For the utilities, planning offers some protection from regulatory second-guessing. Incentive regulation, within certain parameters, offers all parties some of the benefits and risks of the newly restructured markets.

The proposed solution is imperfect and transitional. Imperfect solutions, however, will be common in an industry in which "gas is a commodity, but gas service is not."[203] Some regulation will be necessary in the transition period, and state commissions should make the best possible attempt to assure that an effective regime is in place.

203. *Id.* at 407.

By Darlene M. Denard and Mia T. Vu

The One-Stop-Shop Marketer

We're in a multi-fuel revolution whose banner reads Mass-Marketing Energy.

For those of us who marketed natural gas at the beginning of this decade, the world is not in transition. It is in revolution. Gone are the days of entrepreneurs who could make a 10% margin buying and reselling gas. And the very face of the industry is changing as producers the size of Chevron and Mobil consolidate their gas marketing operations with marketing powerhouses.

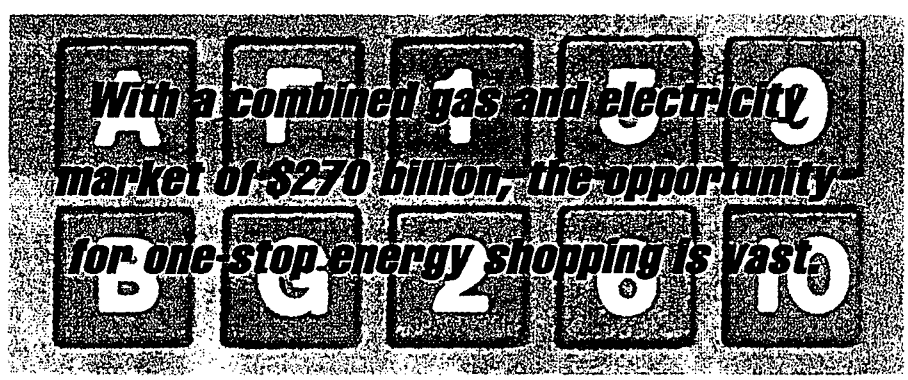
Out of this revolution is emerging a multi-fuel marketplace characterized by mega marketers, interfuel dynamics, technology and new opportunities — for those who know where to look.

Scale is becoming a driving force in this new world. Marketers will have to develop a critical mass to survive the continued pressure on margins. Key players are ramping up their volumes through alliances in order to reduce overhead costs and garner a competitive advantage.

The recently announced alliances of Shell and Tejas Gas, Chevron and Natural Gas Clearinghouse, and Mobil and PanEnergy are testimonies to the upheaval.

The significance of these combinations? The creation of mega marketers with volumes in the range of 6 Bcf to 9 Bcf per day — in an industry where 3 Bcf per day constituted a major presence just a couple of years ago. As this trend continues, the bar is being raised for the rest of the industry.

The likely result? Only a handful of mega marketers will succeed in the national market. Smaller companies will need to develop innovative niches, which can be done on a limited scale.



Multi-fuel dynamics

The cornerstone of the new world is multi-fuel marketing. Natural gas marketers have long marketed gas liquids. Some even market oil and refined products through affiliate relationships. However, the pivotal addition is electricity — an opportunity created by the ongoing restructuring of that industry.

Gas marketers make up about 40% of the companies applying to the Federal Energy Regulatory Commission (FERC) to become electricity marketers. Having prospered through the deregulation of the gas business, these companies are now change agents in the electricity arena. In addition to introducing creative deals, their efforts at the federal and state level are influencing the *shape* of the competitive electricity industry to come.

So far, the leaders in power marketing include Enron, Louis Dreyfus, Electric Clearinghouse, and Louisville Gas and Electric. These companies together represented about 70% of the power marketing business at the end of 1995. (See Figure 1.)

Broadening their portfolios to include electricity gives gas marketers access to the $60 billion *wholesale* electricity market. Perhaps more significantly, this step will position them to participate in what is estimated as the total $200 billion electricity industry when the *retail* electricity market opens up. And even though power marketing volumes are now small (less than 3% of the wholesale market), volumes are expected to escalate this year as the FERC finalizes its ruling on transmission access and NYMEX launches electricity futures trading.

In pursuing the power market, gas companies will need to realize that electricity is not the same as gas. Electricity moves and must be consumed instantly, as it cannot be stored. Unlike natural gas, power cannot be transmitted efficiently over long distances. Except for combustion turbines, generation plants require long leadtimes for startup or shutdown. And, finally, there are distinct regional differences in the

seasonal demand and fuel mix among generators.

These characteristics — speed and diversity — result in a dynamic electricity market.

The evolution of multi-fuel marketing will integrate gas and power markets. With a higher price than energy sources such as nuclear, coal and hydro, natural gas is usually a marginal fuel in electric generation. (See Figure 2.)

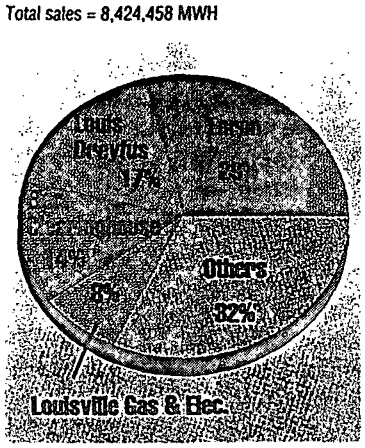
Except in the case of baseload combined-cycle plants, gas demand for electric generation is highly variable. The interplay between gas and competitors for the electric generation market will result in more daily and even on-peak/off-peak pricing for natural gas — a change from the predominant 30-day market.

A competitive electricity market will also increase the competition between gas and coal. Due to the lower marginal cost of coal, existing coal-fired generation will be used more fully. Those regions with excess coal-fired capacity will increase their market share at the expense of higher-cost generators.

Power Marketers

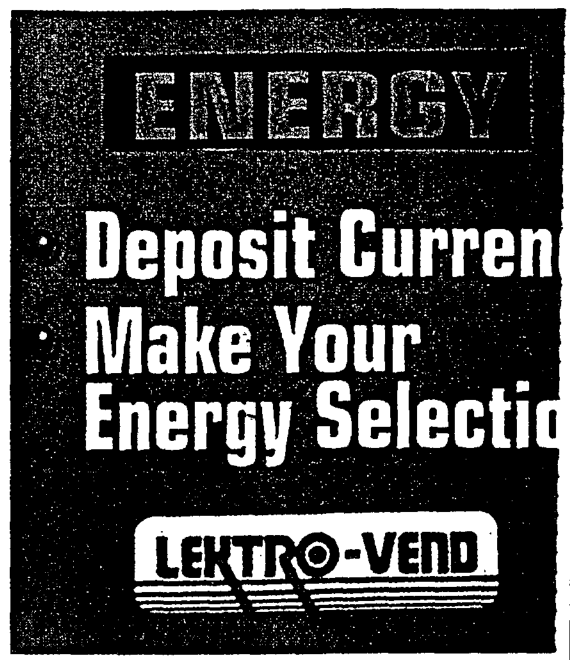
Share of Total Sales in 3rd Quarter 1995

Total sales = 8,424,458 MWH



Source: Edison Electric Institute

Figure 1. Gas-related companies dominated power trading markets in 1995.



New technology

The winners in the new world will embrace technology. Information systems will create a substantial startup cost for new players, but will transform the ongoing administrative burden of the 24-hour business. Plus, technology will provide a competitive edge for those who use it to sift through the data mass to seize profit opportunities. Software developers are creating proprietary models for multi-fuel marketers to rapidly identify trading opportunities and manage financial risks.

The gas and power industries are quickly developing advanced technology to facilitate faster and more complex transactions. The gas industry is revamping its data processing infrastructure to bring the backroom activities of nominating, dispatching and accounting into the 21st century. It has established the Gas Industry Standards Board to simplify business transactions by developing common standards for electronic communication will improve the speed and a of gas invoicing — a long- issue. And the standards ad the industry will also influ effort to standardize com tions in the power business.

To avoid some of the pi the gas experience, the FE proposed a rule requiring r utilities to make real-time i tion on transmission capa pricing available on the I As the information is stand users will be able to c transmission rates across utilities.

Marketers would access to facilitate trading in th bulk-power market. The will eventually move to e trading so that transaction consummated on an el

Numerous alliances have popped up recently. They pair previously unlikely partners: Louis Dreyfus with Duke Energy and Citizens Power with Lehman Brothers.

Aggressive utility affiliates will join the ranks of power marketers to position themselves for the competitive new world. Currently, utilities are limited by regulatory constraints, but they have specific strengths, including knowledge of power-plant economics, transmission systems, and end users. Utilities also have experience in arbitraging among fuels through their dispatch models and fuel-switching capabilities.

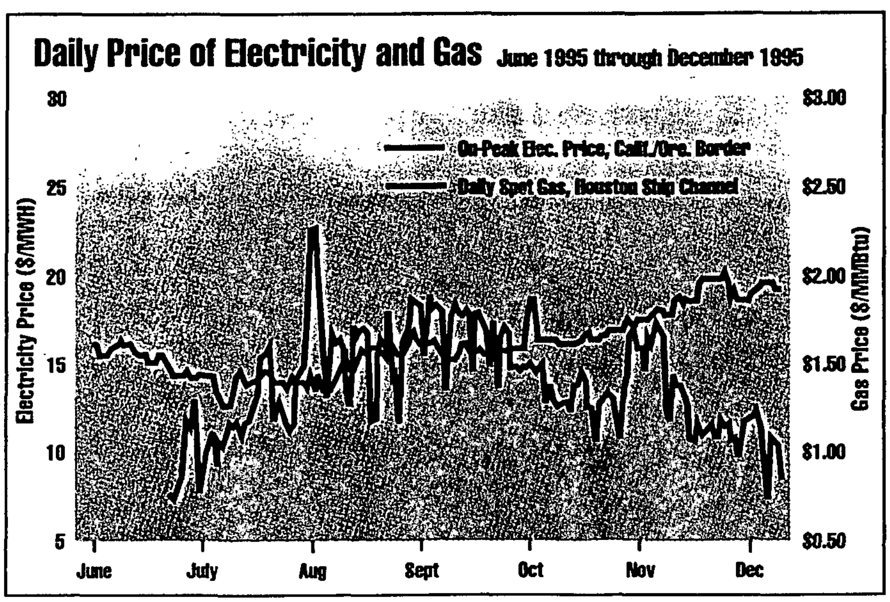
As a result, the most aggressive utilities could be valuable partners or formidable competitors in the multi-fuel market place.

• **Retail marketing.** The destiny of retail competition for electricity and gas has been left to the individual state utility commissions. These will have to wrestle with the issue of stranded costs from regulated generation plants. However, with a combined gas and electricity market of $270 billion, the opportunity for one-stop energy shopping is vast. And multi-fuel marketers will likely offer lower prices to previously captive end users in key regions.

Many of the relationships formed through gas marketing will open the door for selling multiple fuels to large industrial customers. Multi-fuel marketers will also offer customized energy services, including the management of fuel supplies and the development of strategi optimize fuel usage and costs.

Retail marketing will eventu shift the focus from hundred wholesale customers to million industrial plants, shopping cen apartment complexes, and eve ally households.

In this context, new and nont tional players are expected to pa ipate. These new players will li introduce the techniques use marketing telephones, cable te sion, insurance and credit cards.



Source: Dow Jones and Natural Gas Intelligence

Figure 3. Among currently traded commodities, gas is the most volatile, but electricity prices will be even more volatile.

Conclusion

To sum up, the multi-fuel re tion is moving toward the ulti challenge of mass marketing ergy. The magnitude of the ch is significant enough to shift th tire economy. Well-equipped ers will have deep pock marketing acumen and finar skills.

The revolution will be rough tumble, and the outcome cann completely predicted. But one c characteristics that winners share is the speed with which seize opportunities. NGF

Darlene Mason Denard consu gas, electricity and multi-fuel keting. Previously, she held tions in marketing and stra planning at Mobil Natural Also, she is a past president c International Association of E Economics-Houston Cha Mia Tran Vu is consulting economist at Houston Lighti Power, specializing in financia management. She holds a Ph economics from Southern Ill University.

Moody's Special Comment

August 1993

Contacts

Analyst	Phone
K. Christopher Taylor	(212) 553-1653
William G. Christman	
F. Joseph Messina	

FERC ORDER 636 WILL PRESSURE RATINGS OF GAS DISTRIBUTION COMPANIES

FERC Order 636 will cause a **shift of risk** from pipelines to local gas distribution companies (LDCs):

- The new pipeline billing methodology, "straight-fixed-variable", will increase fixed costs for all LDCs, resulting in increased **operating leverage.** Pipeline demand charges are akin to operating leases and firm purchased power contracts but are generally **not disclosed** in most LDCs' annual reports.

- "Unbundling" of pipeline services will provide more scope for "mistakes" by LDCs and regulatory **prudency challenges.**

- **"Capacity release"** (the resale of contracted pipeline space) could become an issue in after-the-fact prudency reviews, if it involves significant discounting of long-term capacity (as opposed to seasonal). This is especially a concern in California, where a significant overcapacity situation is emerging.

- LDCs relying on **spot supplies** face event risk should gas shortages reappear. These LDCs could be forced into unfavorable contracts, as were the pipelines in the late 1970s.

- LDCs with **fixed price** contracts will face increased regulatory risk if gas prices decrease. Those with **indexed** prices will face increased regulatory risk if gas prices **increase** significantly.

- LDCs served by pipelines with significant **"transition costs"** face regulatory uncertainty, especially LDCs in states that previously disallowed full recovery of take-or-pay. LDCs served by the **Columbia** system face further uncertainty.

- Although we expect that most state regulators will be relatively reasonable, Order 636 could become the scapegoat if customer bills increase significantly (e.g. due to further increases in **gas prices**). Regulators would face political pressures to keep bills down, e.g. through prudency challenges or by lowering permitted returns, depreciation rates, or the equity component.

For most LDCs rated by Moody's (i.e. mainly the larger ones), we do not anticipate a significant increase in their explicit "cost of gas" (which includes pipeline charges) due to Order 636. Indeed, once transition costs roll off, there could be a decrease. However, the **risk profile** of these expenses will increase due to the factors noted above, which will have implicit costs: the cost of risk. Under the current regulatory regime, LDCs merely break even on their merchant function (i.e. cost of gas and transportation). They are generally **not reimbursed for the risk** of buying and reselling gas.

LDCs most affected will be the low-load factor, smaller ones that Moody's generally does not rate publicly. At present, the increase in credit risk will have only a **marginal ratings impact** for most publicly rated LDCs. The exception will be LDCs with poor regulatory relations, whose managements are inadequately prepared for the new environment, and those exposed to significant transition costs (especially of the Columbia system).

Longer term, we anticipate a **consolidation** within the industry as a result of Order 636, especially for the smaller LDCs. Many electric utilities which own gas properties are also reconsidering their strategies. If such a consolidation is debt financed or involves a significant amount of goodwill, there will likely be a negative ratings impact.

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Moody's rates 29 local distribution companies, and several of their holding companies (see Table 1). The total amount of rated debt outstanding for these companies is $7.4 billion (not including shelf registrations and commercial paper). In addition, we rate nine "integrated pipeline" companies (Table 2) and 42 electric utilities which have significant investments in gas distribution properties. The total rated debt for these integrated pipeline companies is $7 billion and for these electric utilities is $64 billion. Gas distribution assets constitute roughly 1/3 of total assets for the average integrated pipeline, but only 12% for the average electric utility.

BACKGROUND-FERC ORDER 636:

For a detailed description of FERC Order 636 and its impact on pipelines, please refer to Moody's April 1993 ***Corporate Credit Report: Diversified Gas Transmission***. In summary, the order mandates three basic changes in pipeline operations:

1. **MERCHANT FUNCTION:** Pipelines will no longer have the responsibility to secure adequate gas supplies for LDCs (the "merchant function"). Their only responsibility will be to transport the gas. LDCs will have to purchase their own gas supplies and will have to assume responsibility for short-falls ("supply risk").

2. **UNBUNDLING:** Pipeline services have been "unbundled". Whereas pipelines formerly charged one rate for all services, they must now offer a menu. LDCs will have to decide for themselves how much storage, gathering, upstream capacity, back-up supplies, etc. they need ("capacity risk").

3. **STRAIGHT-FIXED-VARIABLE:** The pipeline billing methodology ("rate design") has been changed. Formerly, customers' bills were split in two: a monthly charge to reserve capacity on the pipe ("demand charge") and another fee based on actual usage ("volumetric charge"). Going forward, all the pipelines' fixed costs can be recovered through the demand charge, and only the (usually minor) variable costs will be based on actual usage. This is known as the *straight-fixed-variable* (SFV) rate design. SFV could increase overall costs for LDCs, and will certainly increase operating leverage.

Transition costs: As part of their merchant function, most pipelines entered into fixed-price, long-term "take-or-pay" contracts, which required that they purchase gas regardless of whether it was needed. Since the pipelines will no longer need these gas supplies, Order 636 has provided a mechanism for them to buy out these contracts. In theory, pipelines will be able to recover these "transition costs" from the end-users.

It is important to note that Order 636 is not a sudden change, but is merely the final, albeit the most dramatic, step in the deregulatory process for pipelines. Deregulation of gas prices started in the late seventies, in response to gas shortages. In the mid-eighties, LDCs and other end-users were allowed to purchase their own gas supplies when the deregulated gas prices declined, thus by-passing high-cost pipeline gas. Since then many LDCs have steadily moved away from total reliance on their pipeline for gas supplies. Several pipelines have already abandoned their merchant function in the last couple of years and shifted to "open access," under which the end-user buys its own gas and the pipeline merely transports it. Buying out the high-cost take-or-pay contracts has also been in process for several years.

LOCAL DISTRIBUTION COMPANIES (LDCs):

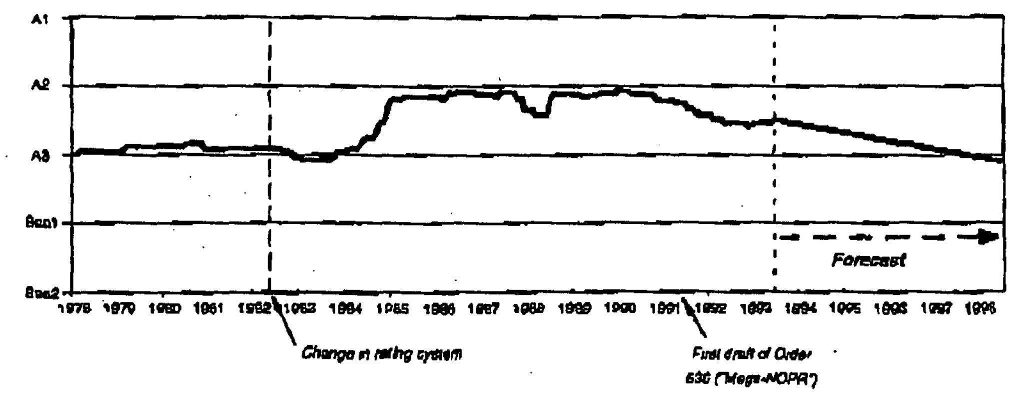
Although gas competes with other energy sources, LDCs are to a large extent a monopoly. States regulate the prices they can charge their end-users (or "ratepayers"). To understand the regulatory structure, it is useful to view an LDC as two separate businesses: transportation and marketing. Unlike railroads or other transportation companies, LDCs (and pipelines prior to Order 636) take title to the product (gas) they ship. This purchasing and reselling of gas is known as the merchant (or marketing) function.

ALTHOUGH THE TRANSPORTATION FUNCTION ALLOWS THE LDC TO EARN A RETURN ON EQUITY, THE MERCHANT FUNCTION IS MERELY A BREAK-EVEN PROPOSITION.

In a rate case, an LDC will estimate the cost of gas, which includes charges paid to interstate pipelines, and will recover this amount on a break-even basis from the ratepayers. However, actual incurred costs are usually quite different from the estimates due to the volatility of gas prices and sales volumes. LDCs are permitted to recover or are required to refund these differences, which are accounted for as "purchased gas adjustment" (PGA). This PGA is a working capital asset or liability, and can cause large swings in an LDCs net working capital position. Although this variance should stabilize over time, in the interim it must be financed, usually through short-term debt. These financing costs are usually also recoverable on a break-even basis.

Prior to pipeline deregulation, both the marketing and transportation functions were low risk for LDCs. Exhibit 1, which shows the average rating of 25 LDCs during the past 15 years, illustrates this point. LDCs have been one of the most creditworthy of all industries rated by Moody's, with an average rating of A2/A3. Post-Order 636, the LDCs' transportation function will remain low risk, but we anticipate higher risk related to the merchant function.

Exhibit 1: Average Rating for 25 LDCs



THE NEW OPERATING ENVIRONMENT - THREE KEY RISKS:

Longer term, we anticipate that Order 636 will cause more risk related to the merchant function, higher operating leverage, and more regulatory risk. Short term, transition costs will be an issue, at least until state regulators determine recovery mechanisms.

1. MERCHANT RISK: Prior to deregulation, the main decision for an LDC was how much capacity to contract for on the pipeline. The contract would be bundled, in that it combined aggregation, balancing, storage, transportation and sales. There was only limited price risk, because state regulators generally permitted full pass-through of the FERC-approved rates charged by pipelines. There was limited supply risk, since the pipelines assumed responsibility for securing gas. There was limited capacity risk, since the pipelines made upstream and storage arrangements. Although most larger LDCs have been taking an increasingly active role in purchasing their own gas, until now they have always had the assurance that their pipeline would be able to supply their peak winter requirements. Order 636 abolishes this "obligation to serve" of the pipelines, which makes the LDCs fully responsible for the merchant function.

Supply Risk: After Order 636, LDCs will have to balance their pipeline input and output. If they fail to do so, they could be subject to balancing penalties from their pipelines. LDCs will have to diversify their gas supply sources, so that production problems in one supply basin do not cause shortages. They will have to manage broker risk (i.e. the possibility that their gas marketers fail to perform on their supply contracts).

After Order 636, LDCs will have to balance purchases in the spot market against more expensive (but also more reliable) supplies reserved under longer-term contracts. Should another gas shortage occur, LDCs without adequate supplies under contract could fail to meet their "obligation to serve". More likely, they could be forced into unfavorable long-term contracts in order to secure supplies, as were the pipelines in the late seventies.

LDCS RELYING ON THE SPOT MARKET FOR A SIGNIFICANT PERCENTAGE OF THEIR GAS SUPPLIES WILL BE SUBJECT TO EVENT RISK SHOULD GAS SHORTAGES REOCCUR.

Price Risk: Closely associated with supply risk is price risk. If an LDC relies on market-based pricing, there is a risk that prices could surge. If an LDC relies on fixed-price contracts, the risk is the opposite: that market prices will decline significantly below the fixed price. A long-term purchase contract with prices reset on a less frequent basis, say annually, would avoid temporary price volatility, but would still expose the LDC to long-term price increases. Hedging through the increasingly efficient derivatives markets is another means of insuring against volatility, but these instruments entail other risks (e.g. open positions or basis risk).

The main reason the merchant function for LDCs will not be as risky as it was for pipelines is that we do not anticipate that many LDCs will enter into high cost take-or-pay contracts. Although it would seem to make sense to lock in today's low gas prices under long-term, fixed-price contracts, at present most regulators do not look favorably on fixed-price contracts for gas utilities given the take-or-pay fiasco at the pipelines. In addition, fixed-price contracts are off-balance-sheet liabilities, which in our assessment have an impact on LDCs' creditworthiness.

HOWEVER, SHOULD SPOT PRICES INCREASE SHARPLY, REGULATORS WILL SEEK WAYS TO KEEP RESIDENTIAL CUSTOMER BILLS FROM INCREASING, WHICH COULD HAVE A CREDIT IMPACT.

A price surge would impact residential customer (i.e. voter) bills, but would also lead to reduced commercial and industrial sales. Since by law utilities are permitted to recover all prudently incurred costs; this loss of commercial and industrial load could cause a further cost shift to residential and small commercial customers. Regulators have a strong political incentive to limit increases in customers' bills. Even if they do not question the prudency of LDCs' gas purchases, they could try to offset the impact of higher gas prices by reducing depreciation rates or permitted returns or the equity component. Any of these would cause a decline in debt-protection measurements, and potentially a decline in credit ratings.

Upstream capacity: Most LDCs will simply convert their existing contract with the pipeline into a transportation contract, with maybe some market-area storage added. However, upstream capacity (such as supply-area storage, gathering, or supply-area mainlines) could pose some risk. A few of the larger LDCs can probably manage this risk, but most LDCs will probably rely on aggregators or their suppliers for upstream capacity. In general, the further downstream (i.e. away from the wellhead) an LDC takes delivery, the less risk we anticipate.

Capacity release: Order 636 provides a mechanism for LDCs to sell their excess pipeline capacity, either on a seasonal basis or permanently. If this capacity release mechanism works as anticipated, it could help LDCs offset some of their underutilized pipeline capacity. However, it could also be used by adversarial groups to argue that an LDC "overpaid" for its pipeline capacity, thus increasing the potential for prudency challenges. This is especially a concern for California utilities, where a significant overcapacity situation is emerging.

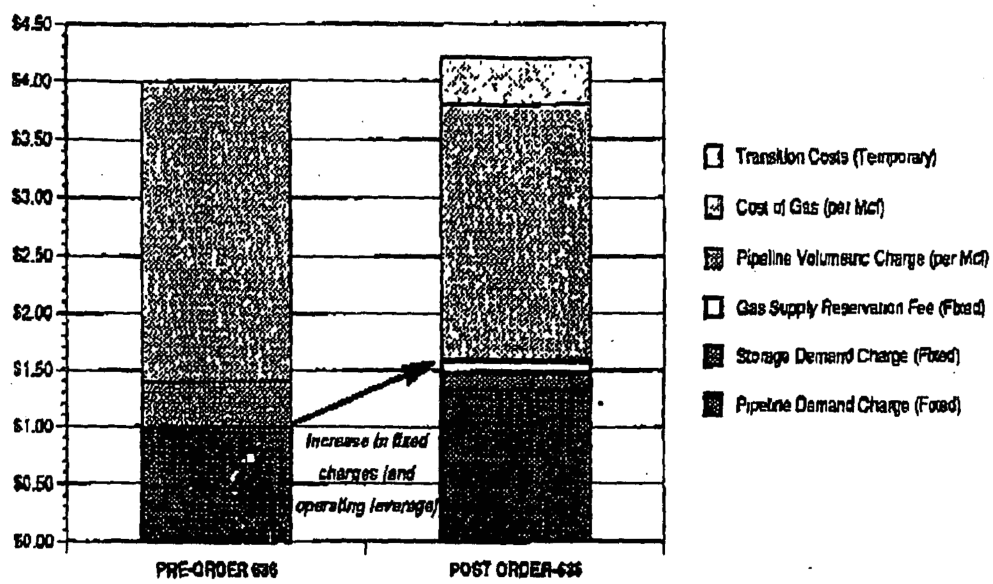
2. OPERATING LEVERAGE: Although several LDCs could face an increase in their pipeline expenses due to the change in billing methodology (straight-fixed-variable) mandated by Order 636, we do not believe that this increase will be significant for most LDCs rated by Moody's. However, Order 636 does cause a shift in the risk profile of "cost of gas", as is illustrated in Exhibit 2. Even if an LDCs total cost of gas and pipeline services remains the same, the composition of these costs changes: a larger share will become fixed and a lesser percentage will be based on usage. As a general rule, the further away from the supply areas an LDC is and the worse its load factor (i.e. capacity utilization), the higher its increase in demand charges will be. This increases operating leverage, which is of course a credit factor. When revenues are lower, e.g. during warmer-than normal winters or economic downturns, there will be a larger impact on earnings and cash flow, all other things remaining equal.

The key fixed costs that will increase are the pipeline and storage demand charges. From a credit perspective, there is virtually no difference between these demand charges and operating leases. Gas supply reservation fees are also fixed charges, although usually minor. Fixed-price contracts combined with "fixed takes" (i.e. take-or-pay) would also constitute significant off-balance-sheet liabilities, but we do not expect that many LDCs will utilize fixed-price take-or-pay contracts. Demand charges are generally not disclosed in financial statements. Sometimes they are disclosed only for unregulated subsidiaries, but there does not appear to be any consistency. Regardless of accounting treatment, we consider demand charges to be fixed obligations, which will be reflected in our credit ratings.

DESPITE THE LACK OF DISCLOSURE, THIS INCREASE IN FIXED CHARGES IS ONE OF THE MOST SIGNIFICANT IMPACTS OF ORDER 636 AS IT RELATES TO THE CREDITWORTHINESS OF LDCS.

Under current regulatory treatment, only explicit costs are recoverable through the

Exhibit 2: Impact of Unbundling and Straight-Fixed-Variable (Cost of Gas per Mcf for Hypothetical LDC)



PGA mechanism. Implicit costs, such as the costs of risk, are not factored into a PGA clause. However, an increase in off-balance-sheet liabilities such as demand charges has implicit costs. Unless regulators increase the equity component of an LDCs' balance sheet or increase the permitted return on equity, any increase in fixed charges must result in an incremental diminution of an LDC's credit strength.

3. REGULATORY RISK: All the risks outlined above are common to many businesses. The key difference for LDCs is that under the current regulatory regime they cannot make a profit on their merchant function. In theory, there should be no downside either since by law all prudently incurred costs are fully recoverable. However, prudency is a subjective judgment and the take-or-pay debacle at the pipelines demonstrates that the merchant function does have significant downside.

After Order 636, the scope for regulatory disallowances will increase. Formerly, the cost of gas and the pipeline demand charge, both paid to the pipeline, were determined under FERC rules. This left little room for prudency challenges. Because these costs will now become unbundled and gas purchases will no longer be subject to FERC jurisdiction, the LDC will have to justify each separate component of its cost of gas to state regulators. Regulators in turn have to answer to their political constituents.

The unbundled cost of gas will include many components. The basic cost of gas (so long it is market based, and there are no price surges) and downstream pipeline charges (so long there is relatively little capacity under-utilization) should remain uncontentious. Most other charges (e.g. for supply reservation, storage, no-notice-service, hedging, or upstream facilities) should also be easily justifiable economically. Even imbalance penalties or losses from capacity release could have economic justifications.

UNDER THE CURRENT REGULATORY STRUCTURE IN MOST STATES, HOWEVER, THE RISK OF AFTER-THE-FACT PRUDENCY CHALLENGES AND DISALLOWANCES WILL INCREASE, EVEN IF ALL PURCHASING DECISIONS WERE BASED ON ECONOMICALLY SOUND REASONING.

Contracting for gas supplies and pipeline capacity often involves long-term commitments, which may make sense in today's economic and political environment, but could be proven "wrong" in the future. Although the pipelines may have had sound economic reasons for entering into long-term take-or-pay contracts in the late seventies, these contracts ultimately caused them significant losses. This is the kind of risk now faced by LDCs.

Many LDCs have chosen to take a pro-active role in working with their regulators regarding their merchant function, and we believe that this reduces regulatory risk. We have also noted that many regulators are becoming more active in educating themselves on their LDCs gas supply strategies. However, consent or even formal approval from regulators regarding gas supply strategies does not eliminate regulatory risk altogether.

Most regulators have indicated that they wish to take a responsible role during the transition, but they will remain subject to political pressures. In addition, the make-up of each commission changes on a regular basis. If customers face significant increases in their bills (e.g. due to higher taxes or a surge in gas prices), regulators would face political pressures to take a tougher line in their LDCs' prudency reviews or rate cases, and could use Order 636 as a convenient scapegoat. This increases LDCs' business risk and could impact their debt-protection measurements.

We do not expect that most regulators will reimburse LDCs for the implicit costs of Order 636. When risk increases, a company's cost of capital increases as well. From a creditors' perspective, when business risk increases, debt-protection measurements must increase commensurately in order to avoid an increase in credit risk.

IF THE INCREASE IN BUSINESS RISK DUE TO ORDER 636 IS NOT SOMEHOW OFFSET, ALL LDCS WILL FACE A MARGINAL DECLINE IN THEIR CREDIT QUALITY.

Affiliate dealings: Many LDCs or their holding companies have gas production or pipeline subsidiaries, which supply or sell gas to the LDC. Often regulators have questioned the prudency of such affiliate transactions. This risk is more prevalent for exploration and production affiliates than it is for pipeline affiliates because pipeline rates are set by FERC, leaving less scope to question prudency. Unbundling will require that the LDCs make decisions on a broader spectrum of issues, thus increasing the risk of prudency challenges. In the past, any disallowances have been relatively minor compared to overall gas costs. Although we do not currently expect a significant change, we will closely monitor LDCs that have significant dealings with affiliates.

Those LDCs that have pipeline affiliates have an advantage over other LDCs; they already have staff experienced in the merchant function. Several companies have simply shifted their staff and purchase contracts from their pipeline to their distribution subsidiary. These vertically integrated gas companies such as Questar, MDU Resources, KN Energy, National Fuel Gas, Equitable Resources, and Arkla are probably least at risk in the new gas purchasing environment.

TRANSITION COST RECOVERY:

Many pipelines still have significant amounts of gas supplies under contract, often at above market rates. These take-or-pay contracts can either be assigned to LDC customers or will have to be bought out. FERC has estimated the cost of these buy-outs ("transition costs") to be above $4 billion (although the final amount will probably be less). However, this amount does not include Columbia Gas, which is currently in Chapter 11.

Under Order 636, transition costs can be recovered from the pipelines' firm customers, including LDCs. LDCs should be able to recover these transition costs from their customers. However, they will probably not be automatically included in the PGA mechanism. Instead, the LDCs will have to file separately for recovery. Even if transition costs will be offset in the long run by lower gas costs (see Exhibit 3), they will be more difficult to justify politically than straightforward cost of gas, thus increasing regulatory risk.

At present, we are aware of only a few states (e.g. Pennsylvania) that could take hard-line positions on their LDCs' transition costs. The risk to LDCs in those states is already reflected in their current ratings. For most states, we are not currently projecting any significant disallowances. However, LDCs which are currently "overearning" could see their permitted returns lowered as a quid pro quo for full recovery. Also, carrying costs (i.e. interest charges incurred due to the timing difference between pay-out and recovery) might not be recoverable in several states.

THE COLUMBIA BANKRUPTCY REMAINS A WILD CARD AND COULD POTENTIALLY IMPACT THE RATINGS OF LDCS ON ITS SYSTEM.

Columbia -- which is currently in Chapter 11 -- has filed for $11 billion in transition costs. While we do not expect the final permitted amount to be anywhere near this amount and FERC has recently ruled that they will not be eligible for transition cost treatment, even 10% or 20% of this amount would be significant. If Columbia's permitted transition costs turn out to be very high, LDCs on its system might encounter some difficulties recovering 100% of their assigned transition costs.

Transition costs should be offset by lower gas costs. The difference between the cost of gas under a take-or-pay contract and market prices in essence becomes the transition cost. Buying out the high-price gas contracts will consolidate this difference into a shorter time period, likely resulting in a temporary increase in total costs, as shown in

Exhibit 3: Effect of Take-or-Pay and Transition Costs
(Average Cost per Mcf for Hypothetical LDC)

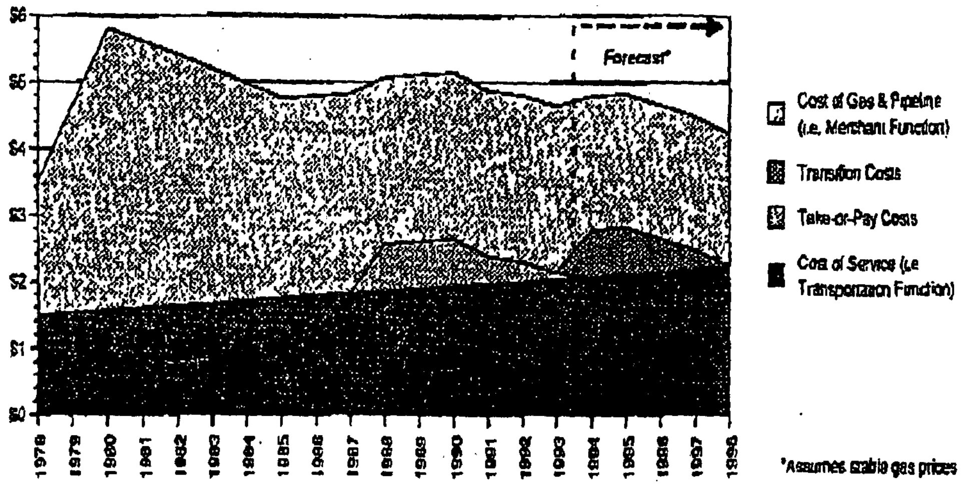


Exhibit 3. Once transition costs are fully recovered, total costs should be lower. However, the removal of fixed-price contracts will also increase the volatility of LDCs' gas costs. Should gas prices surge again, there could be an increase in regulatory risk.

IMPACT ON CREDIT WORTHINESS - FOUR YARD-STICKS:

1. SIZE: Size will be a key factor in how LDCs cope with the new environment. It will be much more difficult for smaller and medium-sized LDCs to be efficient gas purchasers. LDCs by their very nature are somewhat disadvantaged as gas buyers, since their requirements (for heating) tend to be highly seasonal and volatile. Larger LDCs offset this disadvantage through their market clout, gained from large volume purchases. Larger LDCs will also find it easier to diversify their supply sources and broker risk, which could be economically difficult for smaller LDCs. Smaller LDCs could also find it uneconomical to attract a sufficiently large, qualified purchasing staff.

We believe that the smaller LDCs could encounter operational and economic problems in the new gas purchasing environment. Most small LDCs will probably subcontract their purchasing function, but this could entail broker risk as well as a substantial premium. At present, we have taken no direct rating action for the several medium-sized LDCs that we rate, but we are closely monitoring the implementation of their gas purchasing strategies.

Mergers: We believe that "voluntary" mergers of small LDCs are likely to occur, once these smaller systems encounter operational difficulties due to Order 636. The most likely solution to such difficulties would be to merge with a neighboring LDC or to form some type of cooperative, such as in Georgia. We anticipate that most medium-sized LDCs will remain independent, although voluntary mergers to achieve economies of scale (e.g. in New England) should not be ruled out. Most large LDCs rated by Moody's could easily absorb a few small LDCs without a significant impact on their creditworthiness. Cost savings from increased economies of scale should easily offset the acquisition premium (i.e. goodwill), as well as higher taxes if the LDC acquired is a tax-exempt, city-owned system (municipal). However, for a medium-sized acquisition the cost savings would likely be less and the relative acquisition premium higher. Thus, there could be a ratings impact.

Electric-owned LDCs: Many LDC systems are owned by electric companies. Although most of these are managed quite well, several are somewhat neglected.

After Order 636, electric utilities will have to decide the future of their gas operations. Some electric utilities are considering improving their LDC management, or creating a separate subsidiary. Others, however, have chosen effectively to ignore the changing environment. We anticipate that many of these latter LDC properties could be put up for sale once the operational difficulties of Order 636 become more obvious.

CONSOLIDATION AFTER ORDER 636 WILL PROBABLY IMPROVE THE EFFICIENCY OF THE INDUSTRY, BUT COULD HAVE AN ADVERSE IMPACT ON CREDITWORTHINESS IF IT INVOLVES SIGNIFICANT GOODWILL AND DEBT.

2. SUPPLY EFFICIENCY:

Load factor: The more dependent an LDC is on the heating market, the poorer its load factor (i.e. capacity utilization) will be. Load factor is an important variable in calculating the economic impact of Order 636. As a general rule, the lower an LDC's load factor is and the further it is from producing areas, the larger its increase in fixed costs will be. Northeastern LDCs in particular will be most impacted by Order 636.

Storage: Market-area storage can be used to offset to some degree the disadvantage of poor load factors. Of the northern states, Michigan and Illinois are best situated for storage facilities, and Appalachian states such as Pennsylvania, Ohio, West Virginia, and New York also have good potential. Over the next several years, we expect storage capacity to grow rapidly. LDCs that can utilize this storage should be able to partially offset the unfavorable economics of poor load factors, although storage can be expensive.

Pipeline connections: Quite a few LDCs have the benefit of being able to choose from several pipelines. If any of these pipelines have extra capacity available, the LDC will have leverage to negotiate discounts when their contract is up for renewal. It might be economical for an LDC to expand its system so that it interconnects with a cheaper pipeline. Another advantage is that the life of the capacity contract tends to be shorter where there are more pipelines from which to choose. Thus, mid-western LDCs will be less affected by Order 636 than will LDCs in the northeast, where capacity is more constrained.

Transition costs: LDCs located on open-access pipelines that have already abandoned the merchant function will probably avoid significant transition costs. Thus, their regulatory risk during the transition period is reduced. However, there are at least nine pipelines that will have a significant amount of transition costs. LDCs served by these pipelines will face some risk until their regulators determine a recovery mechanism. For eight of these pipelines, the transition costs appear manageable. We do not anticipate major problems for their LDC customers, but we will monitor the regulatory process in each state until a recovery mechanism is determined. LDCs served by the ninth pipeline, Columbia, will face some uncertainty until that situation is resolved.

3. MANAGEMENT: Management's preparation for Order 636 is a key variable in our rating assessment. The managements of most LDCs that we rate are taking a pro-active approach to the new environment, and we believe that this will to a large extent mitigate the increase in business risk. Even if a well-prepared management team does encounter difficulties, they will be more likely to resolve these problems without a significant, lasting impact on debt-protection measurements.

However, not all managements are equally prepared for the challenge of Order 636. The larger LDCs have more resources and market clout, and thus should have less difficulty in adjusting. At present it appears that most medium-sized LDCs rated by Moody's are as well prepared as their larger peers, but we still believe that many medium and smaller-sized LDCs -- mainly those with no publicly-rated debt -- will encounter problems in the new environment. In addition to size, our assessment of how well management will be able to handle the challenges of Order 636 focuses on two factors:

WHETHER MANAGEMENT IS DISTRACTED BY DIVERSIFIED ACTIVITIES, AND WHETHER MANAGEMENT IS CONCENTRATING ON PREPARING FOR ORDER 636 OR ON FIGHTING IT.

Whether an LDC has approached the restructuring ("settlement") negotiations with its pipelines on a contrarian or constructive basis might be a good indicator of how well the LDC is situated for and able to cope with the new environment. It appears that those LDCs that have focussed on fighting the restructuring proposals of their pipelines are those who face the largest cost shifts, transition costs and/or regulatory risk, and are also relatively unprepared for the new environment.

We focus closely on management quality and structure when assessing the impact of Order 636, especially if the LDC has diversified activities. We often find that utilities with diversified operations have ignored their core business. Indeed, diversification is a key factor in many LDC downgrades. With the increase in business risk for LDCs due to Order 636, lack of management focus becomes an even larger credit concern.

4. REGULATORY RELATIONS: Order 636 will create two potentially contentious issues for regulators: gas purchase prudency and transition costs. Thus, regulatory relations will become an even more important credit issue after Order 636. Until formal mechanisms for recovery of transition costs are in place, and each state regulatory commission has developed a track record on gas prudency reviews, we will remain cautious and watchful. We believe that those regulators that have had historically positive relations with their LDCs will continue their constructive approach. Even most of those states that denied full recovery of take-or-pay costs are expected to approach the new environment in a reasonable manner.

THERE ARE ONLY A FEW JURISDICTIONS (E.G. PENNSYLVANIA) WHERE WE ANTICIPATE THAT REGULATORS WILL CREATE SOME DIFFICULTIES FOR THEIR LDCs, EITHER FOR TRANSITION COST RECOVERY OR IN PRUDENCY REVIEWS.

CONCLUSION & RATINGS IMPACT:

Virtually all deregulated industries have seen significant declines in their creditworthiness. For example, the Columbia Gas Systems Inc. went into Chapter 11 as an indirect consequence of changing pipeline regulations, and several other pipelines lost their investment-grade ratings. Our assessment is that the impact of Order 636 on most LDCs that we rate will not be this severe.

We have traditionally viewed the credit profile of LDCs as low risk and stable. Our assessment for the transportation part of their business remains unchanged, but we believe the risk of their merchant function has increased.

UNLESS THE INCREASED BUSINESS RISK AND OPERATING LEVERAGE RESULTING FROM ORDER 636 IS OFFSET BY STRONGER DEBT-PROTECTION RATIOS (E.G. THROUGH HIGHER PERMITTED RETURN ON EQUITY, A LARGER EQUITY COMPONENT, OR FASTER DEPRECIATION RATES) THERE WILL BE A DECLINE IN CREDITWORTHINESS FOR ALL LDCS.

Our current assessment is that most regulators will NOT compensate LDCs for this increased risk. However, we believe that the shift in risk will be manageable for most LDCs rated by Moody's (i.e. the larger ones), and that the decline in their credit quality will be only marginal. There are only a few LDCs that we rate publicly where we anticipate more than a marginal credit impact, but this is already reflected in their debt ratings. The changing regulatory environment has been a factor in all our rating decisions, confirmations as well as changes, in the last couple of years. Since 1992, when Order 636 was issued, Moody's has downgraded seven companies vs. two upgrades.

IN GENERAL, THE INCREASE IN CREDIT RISK DUE TO ORDER 636 WILL NOT BE SEVERE ENOUGH TO CAUSE DOWNGRADES, UNLESS THE LDC'S RATING ALREADY IS BORDERLINE. ON THE OTHER HAND, UPGRADES HAVE BECOME LESS LIKELY.

However, future developments could cause further ratings pressure. The three factors that are most likely to cause downgrades within the next few years are management quality, regulatory relations and gas prices. If we see evidence that our confidence in management's preparedness for Order 636 is not justified, there could be some negative rating implications. The same applies if the regulatory response on transition costs and prudency reviews is stricter than we currently project. Finally, a surge in customer bills during the 1993-94 heating season, e.g. due to a further increase in gas prices, could have negative political consequences and thus amplify the risks of Order 636. We will continue to monitor all rated LDCs for developments in these three areas, and reflect them in our ratings.

Longer term, the anticipated consolidation within the industry could have a negative ratings impact, especially if it is financed with debt and involves significant premiums (i.e. goodwill).

CONSEQUENTLY, THE LONG-TERM RATING OUTLOOK FOR LOCAL DISTRIBUTION COMPANIES IS SLIGHTLY NEGATIVE. HOWEVER, WE EXPECT THEM TO REMAIN SOLIDLY INVESTMENT GRADE.

Table 1: Local Distribution Companies (LDC)

$ Millions (Parent company in parentheses)	Net Plant	Senior Rated Debt Outstanding*	Rating (Utility)	Commercial Paper Rating
Southern California Gas Co. (Pacific Enterprises)	$3,313	$1,630	A2	P-1
Northern Illinois Gas (Nicor)	$1,763	$535	Aa1	P-1
Peoples Gas Light / North Shore (Peoples Energy)	$1,244	$620	Aa3	P-1
Brooklyn Union Gas Co.	$1,229	$634	A1	P-1
Atlanta Gas Light Co.	$1,218	$622	A3	P-2
Michigan Consolidated (MCN Corp.)	$1,115	$298	A2	P-1
Southwest Gas Corp.	$953	$516	Ba2	
Washington Gas Light Co.	$865	$389	Aa3	P-1
Washington Natural Gas (Washington Energy Corp.)	$778	$43	A3	P-2
Oneok Inc	$684	$235	Baa1	
Piedmont Natural Gas Co.	$615	$11	A2	
New Jersey Natural Gas Co. (NJ Resources Corp.)	$592	$113	A2	P-1
UGI Utilities Inc.	$588	$80	Baa1	
Northwest Natural Gas Co.	$575	$336	A3	P-2
Pennsylvania Gas & Water Co. (Pennsylvania Enterprises)	$512	$145	Baa3	
Indiana Gas Co. (Indiana Energy)	$477	$140	Aa3	P-1
Boston Gas Co. (Eastern Enterprises)	$442	$189	A3	P-2
Bay State Gas Co.	$410	$147	A2	P-1
Laclede Gas Co.	$388	$187	Aa3	P-1
Wisconsin Gas Co. (Wicor)	$388	$135	Aa3	P-1
South Jersey Gas Co. (South Jersey Industries, Inc.)	$355	$35	Baa1	
Elizabethtown Gas Co. (NUI Corporation)	$323	$108	A3	
Southern Union Co.	$286	$100	Baa3	
Connecticut Natural Gas Corp.	$269	$11	Baa1	P-2
Alabama Gas Corp. (Energen Corp.)	$255	$68	A1	
Southern Connecticut Gas Co. (Connecticut Energy)	$210	$0		P-2
Cascade Natural Gas Corp.	$175	$89	Baa1	
Providence Gas Company (Providence Energy Corp)	$147	$10	Baa2	
Corning Natural Gas Corp.	$13	$3	Baa2	
TOTAL	$20,180	$7,402		

* Not including commercial paper and shelf balances
** Consolidated numbers

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Table 2: Gas Pipelines And Integrated Gas Companies

$ Millions (Parent company in parentheses)	Net Distrib. Plant	As % of Total Net Plant	Rated Debt Outstanding*	Senior Rating (Utility)	Commercial Paper Rating
Consolidated Natural Gas Company	$1,443	37%	$1,077	A1	P-1
The Columbia Gas System, Inc.	$1,175	34%	$1,419	Caa	
Arkla, Inc.	$1,161	46%	$2,420	Ba2	
National Fuel Gas Company	$720	51%	$480	A3	P-2
Mountain Fuel (Questar)	$419	38%	$135	A1	P-1
Equitable Resources, Inc.	$348	30%	$299	A1	P-1
MDU Resources Group, Inc.	$61	10%	$210	A3	P-2
KN ENERGY INC.	n/a	n/a	$225	A3	
ENSERCH Corporation	n/a	n/a	$718	Baa2	P-2
TOTAL	$5,327	32%	$6,980		

* Not including commercial paper and shelf balances

Natural Gas Focus
A Hart Publication
4545 Post Oak Place, Suite 210
Houston, TX 77027
713-993-9320 / FAX 713-840-8585
ABP

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ABOUT THE COVER: *The cycles influencing global weather patterns in the late 1990s haven't combined in over 300 years, and the outcome may be not only beneficial to gas players, but flamboyant to boot. Digital imagery by Dave Martinez of Digital Innovations.*

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By Vinod K. Dar

The Copernican Revolution

Let's bring a little perspective to bear on the LDC rate base, shall we?

Nicolaus Copernicus was an amateur astronomer with notions strange and heretical for the 16th century. He displaced a system amply supported by tradition that held the Earth was fixed and orbited by the Sun. Copernicus' revolution: The Earth moved and it was the Sun that was the center of the universe.

That same revolution is now coming to the rate base, which is no longer fixed and will not be the center of the energy universe. Indeed, the rate base will be but one more planet, and a modest-sized one at that, orbiting the true center of the energy universe, the energy consumer.

Some managers of the rate base, certain regulators and assorted special interests are responding to this new view of the world by building walls in the mind to keep this heretical idea out. Eventually, the idea will win. The resisting mind will either accept or be rendered irrelevant.

Remember that the French built the Maginot Line to wall themselves off from the Germans after World War I. This supposedly impregnable system of fortifications would have succeeded admirably if time had stood still, but it proved useless when confronted by the new technology of the tank and the airplane and the strategic innovation of the blitzkrieg. The invaders went around and over the forts.

The Line lasted but a few weeks and France collapsed. It was one of the great bypasses of a fixed asset base in the history of the world.

Many a manager of the rate base today seems to be imbued with the French disease and seems unaware or, worse, unconcerned that information technology and intellectual capital are being marshaled to bypass or, in some cases, smash right through the LDC rate base.

A few years after World War II the Communists, having learned nothing, built the Berlin Wall to keep change out. The technology of the fax machine, satellite broadcast and VCR brought down the Wall in 30 years. Today, the Chinese dictators cannot rely on the Great Wall to keep out foreign influences flowing in daily via the myriad technologies of telecommunications and the invisible bypass of cyberspace.

The rate base is a collection of capital-intensive fixed assets accumulated over decades and protected from competition through high barriers to entry. . . and it's being overthrown everywhere.

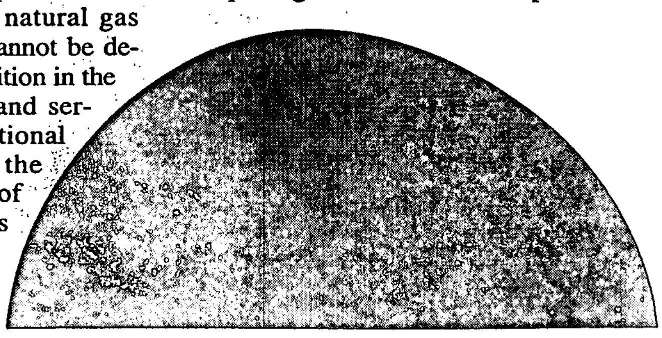
Full competition in natural gas can be delayed but it cannot be denied. Increasing competition in the distribution of goods and services is a systemic national and global trend that the regulated distributors of gas can as little resist as a man on a beach can stay a tidal wave.

Competition in distribution has come to industry after industry — soft goods, groceries, mutual funds, long-distance telecommunications, trucking, railroads, stocks and bonds, over-the-counter drugs, electrical and electronic appliances, office machines and home-renovation supplies. It is accelerating in natural gas and local phone calls and inexorably and inevitably coming to the electromagnetic spectrum and electricity.

The tottering rate base

The rate base is not unique to natural gas LDCs or even to utilities. Its decline is also not unique to utilities. The rate base is a convenient term to define a collection of capital-intensive fixed assets, accumulated over decades, that have been protected from competition through high barriers to entry. These barriers can be regulation, technology, uninformed consumers, tax laws or political power. The geography over which this rate base is spread is called the service area. This geography can be as small as a county or town or as large as a country or sometimes a couple of continents. The service area is not the same as the rate base. Everywhere, however, the rate base is being overthrown.

In telecommunications, MCI and Sprint attacked AT&T's rate base, compelling AT&T to metamorphose



from a phone company into a global network company, cellular phone and personal communications systems are eroding the rate base of the local phone monopolies. Microsoft, Novell and others overthrew the rate base of IBM's operating systems and its software, while Compaq and Apple overthrew IBM's rate base in hardware, forcing IBM to transform itself from a computer company into a "business solutions" enterprise. Wal-mart and Kmart substantially diminished Sears' rate base in general retailing; Southwest Airlines is demolishing the rate base of the large, established airline companies. The emergence of E-Mail, faxes and private overnight-delivery services such as Federal Express and UPS is slicing the rate base of the Postal Service; cable and satellite TV is systematically extinguishing the rate base of network TV. QVC and other TV- or telecomputer-based shopping systems are making gaping holes in the rate base of department stores, while home video providers are doing the same to the large-screen movie theater industry. In the money industry, finance companies, mutual funds and discount brokers have pounded the rate base of commercial banks, S&Ls, and traditional stock and bond brokerage houses.

Indeed, in industries across the world, the combination of highly mobile intellectual capital, decentralized yet ubiquitous information technology, webs of malleable alliances, entrepreneurial risk capital and aroused consumers is clashing with and defeating the massed forces of congealed capital, overengineered hardware, ossified corporate culture, rigid and aloof organizational structure, central planning and decision-making, and entrenched vested interests.

The former combination is inherently low-cost; the latter, intrinsically high-cost. The former is libertarian; the latter, totalitarian.

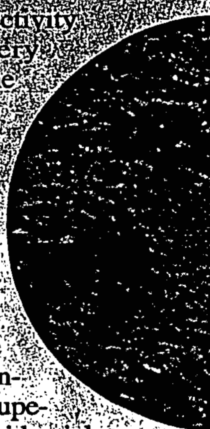
Increasing competition in the distribution of goods and services is a systemic national and global trend. Full competition in natural gas can be delayed but it cannot be denied.

It is hardly surprising that the LDC industry is seeing its rate base come under concerted assault from competitive forces. The industry is huge, remarkably fragmented and high-cost; it's hobbled by a corporate culture that believes regulators, not consumers, are its customers; and it's often a willing agent for tax collection and social engineering agencies at every level of government.

Managers of rate bases everywhere use the same two arguments to justify their peculiar institutions: If customers are given choice, reliability will suffer catastrophically (and civilization itself will fall); and, their business is so unique that the normal economics of competition do not apply. Ma Bell used to say pretty much the same thing before it was broken up. Now AT&T buys 30-minute blocks of TV time to advocate competition in the local phone market, which, at $90 billion per year in sales, is about the same size as the final market for gas, that is, the LDC market.

First segment, then implode

Reliability is practically free (even though LDCs claim to spend extraordinary sums to provide what the competitive market gives almost as a gift to consumers) because it is a function of connectivity and liquidity. Every day, in every way, the gas delivery system is becoming better connected and more liquid. We know, of course, there is nothing unique about the gas business.



By definition, the merchant function, including choice and superior service to the residential sector, is a competitive activity. Moreover, in an unbundled world, functions such as insurance, storage, metering, engineering and construction, development and installation of billing, collection and customer service software and systems are best left to the wit of the enterprise base — not the rate base.

What then is the residual monopoly function of the rate base, and how should it be regulated? Each state will find the answers to these questions in its own particular way, but the general path will be similar.

• **First, the rate base will be formally segmented into three parts:**

1. The first segment consists of services where competition is not in sight and subject to substantial regulation — the black base.

2. The second segment consists of services where the potential for workable competition is high and is regulated to encourage competitive behavior — the grey base.

3. The third segment consists of services subject to substantial competition and lightly regulated — the white base.

The white rate base and the enterprise (i.e., unregulated) base may be increasingly indistinguishable to customers, competitors and managers.

• **Second, the service area concept will cease to be analytically useful.** The traditional franchised service area for electric and gas utilities is a historical anomaly caught between two pincers: market segmentation and market boundary.

1. The energy "market" will fragment into finer segments until each consumer becomes a segment, which is, in turn, a bundle of profit opportunities.

2. The natural boundary of the market (as an arena for competitive strategy and economic contests) will, however, inflate until it becomes regional, then continental, and finally planetary.

Taken to their logical conclusion, gas-electric industry convergence, mass customization and the lateral integration of the merchant and energy logistics (pipe and wire) functions will first blur and then erase the regulatory and franchise distinctions among service areas and the boundaries between the gas and electric industries.

• **Third, the notion of revenue requirements will fall as there won't be a critical mass of truly captive consumers from whom to exact adequate tribute.** With that, the allowable rate of return of regulating will collapse, to be replaced by price caps and shared efficiencies regulation.

Finally, state regulators, left stranded, will lose market share, economic power and staff as their role is changed and diminished. After a very muddy transition, most gas and electric regulation will come under the control of the FERC and the federal courts, with the courts setting the policy — just as in telecommunications.

1. In telephony the FCC recently took away the authority of state commissions to regulate cellular and PCS services; as usual the California PUC resisted federal authority the most.

2. In road transportation, the federal government recently preempted state regulation forcing the CPUC to lay off 10% of its workforce.

The role of state regulators may shrink to that of policemen and safety inspectors, with some rate-setting authority on the residual monopoly function associated with purely local, small pipe and wire business activities.

State PUCs will attempt to create regional regulatory authorities, but these will be transitional arrangements at best.

The role of state regulators may shrink to that of policemen and safety inspectors, with some rate-setting authority on the residual monopoly function associated with purely local, small pipe and wire business activities (i.e., the black base).

And the customers?

Sooner than most LDC executives believe possible, the customers of the typical LDC will become not the final consumers, but a few national and many niche nonregulated merchants of energy products and services.

• With the sales function severed from the rate base — perhaps taken over by the large, well-capitalized enterprise-based affiliate of the LDC, as most LDCs become subsidiaries of holding companies and many are merged out of independent existence; and

• With metering and billing long since migrated out of the rate base, the LDCs will find themselves being transformed from an essential utility for consumers to *a cost of doing business* for merchant shippers. These shippers will not view the LDC as a strategic or any other kind of partner. Many will pretend, for a while, that they wish to form strategic alliances with LDCs, but these will be shown in a few years to be rather obvious devices to separate LDCs from sales services to final consumers, including residentials. The shippers will not hesitate to ruthlessly squeeze the margins of LDCs.

At the end of this not terribly long journey, LDCs will find their (a) rate bases severely shrunk, (b) logistical margins compressed, (c) rates of return subject to substantial volatility, (d) dividends reduced, and (e) enterprise value imploded.

The Copernican revolution will then be over.

LDC executives who anticipate this revolution and begin the orderly transfer of assets, opportunities, skills and functions to their enterprise bases will have little to fret about. LDC managements that do not will also have little to fret about because they will be taken over and replaced.

The energy world will go on — cheaper, better, faster. NGF

Vinod K. Dar is director of Worldwide Strategic Services at Hagler Bailly Consulting, Inc. in Arlington, Virginia, and a contributing editor to Natural Gas Focus.

By Paulette Whitcomb

Just in Time

What is the natural gas industry's new paradigm?

They called their conference "Just in Time" — and their timing was right on target. What took shape was the conference organizers' dream: The issues discussed were the issues the industry was hot to discuss. And so it was that a record number of attendees from North America came to Denver for the 7th Annual Rocky Mountain Natural Gas Strategy Conference and Marketing Fair, hosted by the Colorado Oil & Gas Association (COGA).

All sessions were mobbed, not just the capacity release one featuring the El Paso and PG&E reps on the same dais.

What were these timely issues?

• **Growing competition.** Telling producers up-front that what they need are lower prices and plentiful supply at the burnertip, Tejas Power chairman Larry Bickle cited a four-step way: Support hubs; support LDC unbundling; support incentive-performance rates; and focus on the daily swing market. As the hub system interconnects, the pipelines will be pressured into significant efficiencies, forecast Bickle, and selling at hubs increases choice. In the short term, producers need to learn to use salt dome storage's quick turnover — a few days or even just hours — so as to benefit from cash price volatility.

While co-keynote speaker Paul M. Anderson, Panhandle Eastern president and CEO, drew a different route to success, it only appeared contradictory. In effect, attendees agreed, the industry needs to heed both experts. Among Anderson's producer survival skills: Recognize the change in the market, utilize the financial markets, invest in intelligence and explore strategic alliances.

On the Canadian front, Roland George, director, natural gas, at the Canadian Energy Research Institute, politely but firmly intoned, "Make the decision to let the market work, let it find its level." And hammering home the conference theme of long-term strategy, conference chairman and COGA mainspring Fred Julander likened the Canadian gas-import situation to "having our glass three-quarters full." End users need no longer fear product unreliability, noted the longtime Rockies producer: A huge volume of supply steadily available at reasonable prices breeds confidence in those planning multimillion-dollar gas-fired plants.

"All of us will be market-driven. We'll even train our lawyers to become marketers." Peter E. Weidler, Transwestern Pipeline marketing vice president

• **Financing.** "Bankers in 1995 are different from the bankers of the mid-'80s," noted Banque Paribas' Jean-Marc Bonnefous. "Today they understand and even like dealing with price volatility." Outlining options in a declining gas market, the Commodity-Indexed Transactions Group vice president endorsed diversifying the gas portfolio by creating synthetic price exposure, that is, basis swaps; by selling longer-term; by using prepayment facilities, monetizing long-term contracts and selling Section 29 tax credits.

Surveying the energy equity market, Tom Petrie, Petrie Parkman & Co. chairman and CEO, pointed to renewed uncertainty in the commodity price outlook, more competition for capital and projects, and the emergence of gas storage as a new market factor. "A preference for gas has diminished, while a preference for liquidity is evident," he summarized. "We have a volume-driven situation, with visible production volume growth favored. The market has embraced technology. And a consolidation trend is under way — not a merger mania, but elegant fits."

• **Gas and electric deregulation impacts.** Ron Denhardt, a principal at Jensen Associates, projected the likely changes from traditional cost of service regulation and their implications: Deregulation or light-handed regulation of the capacity release market; incentive-based rates; shakeout of marketers, and strategic alliances among producers, marketers and LDCs, leading to a concentration of shippers; and producers' need to protect themselves from loss of value added caused by this increased concentration.

What's a gas supplier to do? asked Lincoln Anderson, manager of energy supply at Portland General Electric. His prescription: Redouble efforts to learn the electricity industry, because today the power industry understands the gas industry better than the gas industry understands power. Learn the technical complexities of the power industry, who your competitors — gas marketers or coal suppliers, for instance — are and what they're doing, who and where the generators are and when they operate. "Add flexibility through storage to an industry that has difficulty storing, and provide flexibility to match the generators' requirements," urged Anderson.

"Regulation made it affordable to build coal and nuclear plants with amortization periods of 30 years or more," said Steven Lewis, senior vice president of Duke/Louis Dreyfus Electric Power. "But deregulation will force cheaper fixed-cost alternatives with shorter ROIs." The increased efficiency of smaller gas-fired units makes them a viable alternative for industrial customers, he noted, underlining the significant advances in natural gas turbine technology with lower fixed costs. Today, industrial customers are beginning to make their own supply decisions; in the longer-term macro view, there's increased demand for intermediate and peaking capacity, price signals create incentives to invest capital, and merchant plants are developed with equity owners taking much more market risk.

And, oh yes, retail wheeling is already here, noted Lewis, and natural gas is indeed the fuel of choice. NGF

Letter...

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Its authors are Merton H. Miller, professor emeritus of the University of Chicago's Graduate School of Business and winner of the 1990 Nobel Prize in economics; and Christopher L. Culp, senior fellow in financial regulation with the Competitive Enterprise Institute in Washington. These prominent authors commented that:

"Its [the CFTC's] extremely broad definition of futures calls into question the legality of numerous financial transactions." And, "In almost total disregard of its previous rulings and statements, the CFTC defines a future as any financial contract that:

1. calls for future delivery at a price or formula set at the contract's inception,
2. can be satisfied either by physical delivery or an offsetting transaction, and
3. is used either to speculate or hedge rather than to take delivery."

These criteria would apply to almost every derivative contract. A futures contract is illegal unless it is traded on an exchange.

Are derivative contracts going to be illegal unless traded on a U.S. government-regulated exchange?

Forward contracts for physical delivery are excluded by statute from CFTC regulation. Are we sure the CFTC knows the difference between a forward and a future?

The WSJ reports that Mary Schapiro denies that her agency is going after swaps. Is this a cover for her agency trying to expand its jurisdiction?

Do the CFTC's criteria apply to take-or-pay contracts?

What will the International Swaps and Derivatives Association (ISDA) do?

Can other industry associations involved with users of derivative contracts help?

Should Congress leave the markets alone to self-regulate?

Should Congress regulate the regulators?

What happens next to counterparties who hold "in the money" derivative contracts?

Thank you for alerting your readers.

Brooke Wunnicke
Diane B. Wunnicke
Denver, Colorado

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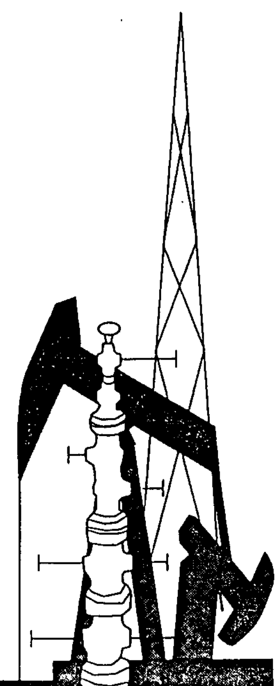

Swift Energy Company
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Houston, Texas 77060

800/777-2412 • 713/874-2700

STATE POLICY & ECONOMIC DEVELOPMENT IN OKLAHOMA: 1996

A Report to

OKLAHOMA 2000 INC.

OKLAHOMA 2000, INC. 330 N.E. 10TH OKLAHOMA CITY, OKLAHOMA 73104-3200

Donald A. Murry

GAS AND ELECTRIC DEREGULATION AND ECONOMIC DEVELOPMENT EFFECTS IN OKLAHOMA

Introduction

In recent months, the Oklahoma Corporation Commission (OCC) has sponsored a symposium concerning the restructuring of regulation of the retail electric and gas industries in Oklahoma, and a legislative Electric Utility Task Force has been meeting to consider deregulation and a broader range of related issues.[1] This local interest in deregulating the end-use, retail markets for electricity and natural gas is part of a national trend that includes similar interest in other states, federal deregulation of other sectors of these industries, and a broad move to deregulate a number of other industries at both the federal and state levels.[2]

More specifically, the federal agencies are moving to deregulate the wholesale markets,[3] and other states are investigating how to deregulate the retail markets (which the OCC regulates in Oklahoma). State companies buying or selling natural gas or electricity in the wholesale or interstate natural gas markets already face competitive pressures; observers generally agree that the trend will continue. For the responsible state officials—members of the executive branch, legislators, and regulators—this creates an encircling environment of deregulation. However, some of the most difficult issues at the state level are yet to be confronted.

Because of the national scope of the deregulation movement and the interconnected energy markets, Oklahoma politicians face special circumstances. Oklahoma is a low-cost energy state and does not possess constituencies strongly motivated to restructure these industries. In addition, of course, Oklahoma is a major producer of natural gas.

Donald A. Murry is Professor of Economics at the University of Oklahoma, Norman, Oklahoma.

The policy issues for Oklahoma have efficiency implications in the state's energy industries and equity concerns which could impact many groups.

The Public Purpose of Regulation

There are relatively few, if any, effective alternatives to the utility services, and centralized production and distribution of service brings about certain efficiencies in supply. For example, the distribution of electric power and natural gas has certain efficiencies. The efficiencies of providing service lead to a single firm being the least-cost method of supplying service, and a community will provide a franchise, which may or may not be exclusive to the firm, creating a virtual monopoly. In exchange, the company assumes an obligation to serve all qualified customers in the territory.[4]

As a control of the market power of the investor-owned franchised utility, the state regulatory body is empowered to approve the rates charged to customers. In this way, regulation serves as the force that limits customer rates, just as competitors would in competitive markets. The franchise serves to limit entry, and the regulators limit prices.

The Regulatory Process

The regulatory process, adjudicated as a method to balance the interests of company investors and ratepayers and also provide equity among ratepayer groups, allows the company to collect revenues that are equal to the cost of providing service to customers. The general standard applied throughout the U.S. follows the *Hope Natural Gas* decision by the U.S. Supreme Court that states that the rates should "...enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed...."[5]

To meet this standard, the company must collect revenues to cover costs and to attract capital. These costs include all operating costs; all taxes and depreciation on the plant used to provide service to customers; and a return allowed on the net investment in the plant used to provide service. This plant investment is known as the rate base. The methods of accounting for costs and the rate base, as well as for determining how large a return to allow, become more important to the involved parties than the stated purpose of the regulatory standard.

Criticisms of Regulation

Critics of regulation attack the process as ineffective and argue that it produces adverse economic consequences. Although the criticisms' legitimacy is important conceptually, in some ways their prevalence is more important. The broad range and frequency of criticisms of the regulatory process have surely aided the movement toward, and the political acceptance of, deregulation.

An important criticism addresses the arbitrariness of some rate designs produced through the regulatory process. A characteristic result of regulation is the prevalence of excessive cross-subsidies; that is, charging a price to one group of customers that is high enough to support subsidies for other customers.[6] These cross-subsidies lead to price differentials among customer groups that are not consistent with the differentials caused by differing costs of service. For example, the price per unit of service to the residential customers is higher than the price per unit of service to larger, industrial customers, but typically the residential cost differentials are even higher. Consequently, a major concern about the regulatory process is the setting of rates that are not reflective of costs, as would be the case in competitive markets.[7]

A group of theories has criticized regulation for its susceptibility to political influence by parties interested in the regulatory results. One of these simply addresses the influence of the regulated companies on the regulatory process. This argument is descriptively called the "capture theory."[8] Similar but more elaborate theories attempt to explain the political process of regulation, and the circumstances governing regulatory outcomes. These theories recognize that the state's power to regulate is the power to redistribute wealth.[9] They focus on the desire of politically elected officials to stay in office, and the exchange of political support from such entities as groups of customers or regulated companies interested in a politician's attention to regulatory appointments and policies.[10]

Another group of studies has questioned the efficacy of regulation. They argue that regulation does not achieve its objective to set rates at levels lower than they would be without regulation. Probably the most widely recognized study of this type claimed that, empirically, there were no measurable benefits of lower rates as a result of regulation.[11] However, this was a comparative study based on a period before all states had regulatory bodies. More recent studies have concluded that regulation does result in lower rates than would occur in unregulated markets.[12]

In economic literature, the most widely recognized efficiency criticism of the regulatory process is that of Averch and Johnson.[13] They used a theoretical model to argue that the rate of return allowed by regulatory bodies on a firm's investment, or rate base, encourages a company to overinvest in plant; that is, the increasing of investment to levels that are beyond the most efficient levels. The strong assumptions of the model have opened it, in turn, to strong criticism, and Averch and Johnson's viewpoint remains controversial. Critics of their theory have pointed out that investment will always raise costs, which in turn lowers profits in the short term. Nevertheless, theirs is a view still held by many.[14]

Although controversy around these observations remains, taken together they present a broad front of criticism of the regulatory process and they provide a conceptual base for the current environment supporting the deregulation movement. From that perspective, they are significant.

The Changing Natural Gas and Electric Markets

The long-standing structural and pricing relationships for electric and natural gas companies have been changing, as legislation and regulatory decisions open various stages of the natural gas and electric utility industry to competition. On the supply side of the market, the result is freer entry and market-based rates. On the demand side of the market, consumers have a broader range of service choices. For example, in the natural gas industry, relatively free entry and market-based pricing have replaced regulation in the producing and pipeline segments and in much of the distribution segment. Now there is increasing interest and some experimentation with competition for the smaller end-use customers also.

In the electric industry, there is relatively free entry into the generation segment, and a Federal Energy Regulatory Commission (FERC) proposal for access and cost-based, market driven rates in the high-voltage transmission systems. In many states there is increasing interest in opening the retail segment of the industry to competitive power suppliers, at least for the largest customers.[15] Deregulation advocates expect competitive pressures from freer entry and market-driven rates to replace regulation as a limit to price increases.

Competition also will provide groups of customers with alternative supply sources and afford at least some customers the opportunity to tailor their service to their specific energy needs. On the other hand, the existing cross-subsidies are not sustainable in competitive markets where pricing is based on the incremental costs of additional supplies. Even with net efficiency gains, surely some customers will gain and others will lose with the removal of cross-subsidies.

Although there are some similarities between the restructuring of the natural gas industry and the electric industry, there also are some important differences. Many analysts of the electric industry have used natural gas, which is further along toward deregulation, as a model. That may be instructive for the significance of such changes as open access to the transmission system, but it may be deceptive as well. The industry differences are also very important.

Natural Gas

The natural gas industry consists of three separate levels: production, high pressure transmission, and local distribution. Each has undergone different steps in deregulation. Combined, the results provide a more complicated, but immeasurably more flexible, natural gas system that supplies an array of services for gas consumers.

Production Deregulation

For roughly three decades, federal authorities regulated the wellhead ceiling prices for gas sold in the interstate market. The Natural Gas Policy Act of 1978 was the beginning of the end of wellhead regulation, as it initiated phased deregulation; however, the role of the market is often overlooked. Increased supplies caused the field markets to clear at price levels less than the FERC ceiling prices in the early 1980s.

The supplies at the wellhead also stimulated the opening of the pipeline system to common carrier transportation. Financially pressured producers and pipelines arranged to transport low-priced gas directly to large industrial customers in place of high-priced gas flowing under prior long-term contracts. That is, the markets led regulatory action in setting field market prices, as well as encouraging the end-user transport of natural gas.[16] Eventually (and anticlimactically), Congress deregulated the remaining sectors of the wellhead prices.

As a producing state, Oklahoma found the deregulation of the wellhead market a significant regulatory development. While Oklahoma today has a declining share of the national market, an efficient natural gas industry remains an important economic factor to the state.

Pipeline Deregulation

With many large customers or local distribution companies (LDCs) acting as agents for customers purchasing natural gas in the field and transporting gas under various emergency provisions, the pipeline system moved a long way toward open access in the early and mid-1980s. Pipelines, producers, and customers all were motivated to effect such transactions. Subsequently, FERC Orders 436 and 636 codified and expedited the pipelines' movement to open access, but again the inherent market forces opened the system to competition.

Now, open access to the pipeline system, freedom for the pipelines to withdraw from certificated service, and the opportunity to offer noncertificated service have added flexibility to the supply side of the market. Straight fixed-variable rates, which distinguish between the purchase of pipeline capacity and a volumetric charge for gas, send pricing signals to customers that are linked to the cost of providing service. In this market, purchasers can choose among a range of services to fit their specific needs.

The ease of exit and entry has brought market participants, suppliers of services, and purchasers to the transportation services market in sufficient numbers and diversity for a workable competitive market. The rates are now market-based. It also has encouraged a physical restructuring of pipeline companies, often through horizontal and vertical mergers, to achieve cost reducing efficiencies and improve supply and market access. Ironically, increased entry and competition have led to fewer, larger, but surely more efficient interstate pipeline systems in the U.S.

LDC Deregulation

The step being confronted now in natural gas deregulation is in the retail market and at the state level.[17] With market forces setting the prices in the wellhead market as well as the rates for transmission and storage services, the LDCs now face competition in the retail market.[18] At the same time, there is regulatory interest in permitting more competition for the end use customers. For example, several state commissions have held hearings or set up pilot programs to test the feasibility of permitting all customers, including core residential customers, to purchase gas from nonutility suppliers.[19]

Impact on LDCs. Pipeline open access introduced new operating risks to the LDCs. With the pipelines no longer serving as the only supplier of gas to the LDC, those companies now faced gas supply acquisition risks. Nondiscriminatory open access of the distribution system to third-party transport will expose the LDCs to new risk from a competitive transport market.

From a regulatory standpoint, the issues of LDC deregulation continue to evolve, and some of them are tough politically. For example, increased competition in the retail market raises the question of whether or not the obligation to serve, under the public service theory, is altered or whether it should be altered. In addition, the unbundling of LDC services, with the requisite shift of cross-subsidies, is likely to shift the allocation of costs, and rates, of customers.

Impact on the Core Customers. The core customers, primarily the residential and commercial heating customers, will find their supplies of natural gas protected somewhat from supply failure by the LDCs. These buyers will continue to purchase system supply and be protected by regulatory policies, at least for a period of time. However, as diversity of supplies maintained by the LDC declines, the core customers will be exposed increasingly to market price fluctuations. In addition, the risk exposure of the core customers to price variability will increase over time, as more and more customers shift to noncore status and as market intermediaries (e.g., purchasing cooperatives, service companies, and brokers) fill the interstices in the market between gas suppliers and customers.

Rate design will shift from the cross-subsidies to cost-based rates. Pricing closer to or at marginal costs for the nonweather-sensitive customers with relatively more elastic demand will cause cost reallocation to the core customers who have a relatively less elastic demand. That, in turn, will encourage more customers to shift from the core to the noncore category.

Impact on Industrial Customers. The noncore transportation customers have, for the most part, already enjoyed the benefits of expanded choices. They have also absorbed the risks of gas acquisition, gas deliverability, market price fluctuations, and contracting commitments from pipeline deregulation, and they have developed the expertise to operate in competitive markets. If and when LDCs become open-access unbundled providers, the supply responsibilities will continue to shift to these end users seeking least-cost service. The noncore gas customers already are becoming the customers for the new services of brokers, marketers, storage and peak shaving services, and the financial instruments that compensate for and hedge against market fluctuations. Expertise in managing gas supplies that has been growing since the early 1980s will now be required by smaller and smaller customers.

From the standpoint of economic development and the use of natural gas as a critical state resource, maintaining competitive prices to this customer group is a legitimate state policy objective.

Impact on Producers. For producers, pipelines, and alternative suppliers, the deregulation of local distribution companies will expand, but complicate, their market alternatives. To get the best market prices, producers will find it necessary to be located well geographically and competitively in the market.

Producers no longer will have just one or a very few purchasers. Their markets will be in geographically diverse regions of the country, and they will have to maintain a marketing capability to reach their markets. As restructuring at the retail level continues, the sales outlets will only multiply further. New suppliers of storage and other services will enter the market. Pipelines and alternative suppliers will develop retail customers behind the LDCs that were formerly protected by the franchise of the utility.

Electric

The Oklahoma Corporation Commission symposium in 1995 and the hearings of the legislature's Electric Utility Task Force demonstrate the emerging interest in restructuring the electric utility industry in Oklahoma. Although in the early stages of discussion and with uncertain results, the local policy debate has begun.

Electric Generation Deregulation

Federal legislation in 1978, the Public Utilities Regulatory Policies Act, set the stage for deregulation in the market for new generation. That legislation mandated the interconnecting of nonutility generators, such as cogenerators, to the utility systems and created competition in the generation market by requiring that utilities purchase power from "qualifying facilities."[20] This legislation ended the virtually complete vertical integration of generation, high-voltage transmission, and low-voltage distribution services of the electric utility companies.

Another major deregulation bill was the Energy Policy Act of 1992. It had two components that provided impetus to the restructuring of the electric utility industry. First, it provided for an additional broad category of nonutility power producers, the Exempt Wholesale Generators. Second, it gave FERC the authority to order utilities to wheel over their high-voltage transmission lines.[21]

Modern technologies also lowered the financial barrier of entering the generation sector. As the modern technologies improved the efficiencies of smaller plants, such as gas turbine and gas combined cycle plants, it became easier for nonutility generators to compete successfully with central station generation. These competitive forces are now such that the FERC is moving toward market-based rates in the wholesale power market and opening the transmission systems to access by third parties.

Electric Transmission Deregulation

The sale of power among utilities via the national transmission grid, wholesale wheeling, and the resulting competition are forcing the issue of opening the transmission system for easier market entry. The FERC has become sufficiently confident in the competitive forces in the wholesale power market that in 1995 it issued a Notice of Proposed Rulemaking concerning open access to the high-voltage transmission system.[22] In the summer of 1995, the California Public Utilities Commission approved a proposal for submission to the California State Legislature that would separate the transmission system from the generation and distribution sectors of the industry.[23] The California Commission designed this proposal to assure equal access to transmission for all utilities wanting to wheel power to their distribution systems. Although the final approval of that proposal is in doubt, it has served as a focal point for the discussion of wholesale power market deregulation at the state level.

Electric Distribution Deregulation

Although there are considerable pressures to open the distribution segment of the electric utility industry to choice for customers, as has been done in the natural gas industry, such a transition will be somewhat more difficult in the electric industry. The electricity product is a complicated one, delivered on instantaneous demand that varies constantly. Because of the nature of the physical connection to the end-use customers and the nonstorability of electricity, the prospect for economies of scale efficiencies and the arguments for central control are strong. Large industrial customers will demand the right to buy power from the lowest-cost sources. Many were able to reduce their gas costs by direct acquisition from the field market, and the parallel is apparent. To access alternative power sources, customers will pay a transmission charge, if necessary, and a distribution charge to their connected utility. This practice, called "retail wheeling" would permit the customer to shop for power and buy from the cheapest sources.[24]

Because there is such a large differential in the U.S. in electric rates regionally, retail wheeling is a more significant economic development issue in some areas than others. In the high-power-cost states, industrial customers that compete with companies in low-cost areas are at a competitive disadvantage. Although being a low-power-cost state may remove some of the urgency in Oklahoma, there is no reason to believe that there is no interest in even cheaper power costs.

From the standpoint of regulators, the concept of retail wheeling creates several problems. First, there is the tough policy question of whether central control of a distribution system is more important than broader customer choices. For regulators, that is likely to focus on the issue of the utilities' obligation to serve if customers are given freedom to leave the system more readily. Second, there are critical equity questions between investors in the private utilities and customers, and among groups of customers.

As to the equity issue between utility investors and ratepayers generally, the regulators must find a mechanism to account for the facilities that utilities built to serve the customers who now seek off-system service. Investments in plant that are no longer needed for customers choosing other service (called "stranded capital") remain in the rate base of the utility. However, if the customers that choose off-system service avoid paying the costs of those facilities, those capital costs will be absorbed by customers remaining on the system. An important issue related to the obligation for the plant investment is the rights of customers that leave the system. Regulators must determine when customers have the right to return to utility service if market-based costs exceed utility rates. There is a feasible reallocation solution, but it is a complicated one in practice.

As to the equity issue among customers, the market-based rates will eliminate any sizable cross-subsidies among customer groups. Many companies will be forced to lower industrial rates and raise residential and commercial rates. Nationally, the prospect of retail wheeling is an important one, but it promises to be complicated and contentious.

The Implications for Oklahoma

Natural gas and electric restructuring is a significant development to the state's economic future because these are infrastructure industries. They affect the well-being of Oklahoma's citizens and the competitiveness of the state's industries.

Table 1

Average Revenue Per Kilowatt Hour
Oklahoma and Contiguous States, 1994
(Cents per kilowatt hour)

	Average Rate	Residential	Commercial	Industrial	Rate Tilt
Oklahoma	5.9	7.0	6.1	4.1	1.7
Arkansas	6.5	8.1	6.9	4.8	1.7
Kansas	6.6	7.9	6.7	4.9	1.6
Missouri	6.2	7.3	6.2	4.6	1.6
New Mexico	7.2	9.1	8.4	4.7	1.9
Texas	6.5	8.1	7.1	4.3	1.9

Source: U.S. Department of Energy, Energy Information Administraiton, *Electric Power Annual*, 1995, (Vol. 1) p. 46.

Table 2

Average Price of Natural Gas
Oklahoma and Contiguous States, 1993
(Dollars per Thousand Cubic Feet)

	Residential	Commercial	Industrial	Rate Tilt
Oklahoma	4.94	4.42	2.2	2.2
Arkansas	5.38	4.42	3.31	1.6
Kansas	4.91	4.06	2.64	1.9
Missouri	5.37	4.76	4.25	1.3
New Mexico	5.46	4.31	3.82	1.4
Texas	5.91	3.91	2.53	2.3

Source: U.S. Department of Energy, Energy Information Administraiton, *Electric Power Annual*. 1993, p. 64.

Interstate Competition

Oklahoma is a low-cost energy state and, as shown in Tables 1 and 2, it has low delivered natural gas and electric rates for all classes of customers. Not only is Oklahoma lower cost than the widely recognized, high-cost energy states on the East and West Coasts, but Oklahoma is a low-cost state regionally, as well. Not only do customers benefit from low-cost service, but the low-cost gas and electric service have developmental benefits. Since the industrial rates will be the first to move to the cost-based, market-driven levels, the low industrial gas and electric rates suggest that the rate impact in Oklahoma may be less that in the surrounding states.

Table 1 also shows that the average electric rate tilt in Oklahoma, here shown as the ratio of the average residential rate to the average industrial rate, is similar to most surrounding states. Texas and New Mexico are somewhat higher. By comparison, the average rate tilt for all gas systems in Oklahoma and Texas is relatively high. In competitive markets, the cross-subsidies will be forced from the rate structure and the rates will more closely follow costs. Consequently, where there is a rate tilt that differs from surrounding areas, competition will, in all likelihood, diminish or remove that differential. Sellers will entry submarkets and sell to customer groups where rates are high or to individual customers. In all likelihood, competitive pressures will increase the rate tilt, the ratio of the average residential rates to the average industrial, and also drive the industrial rates in the region to the same cost-based levels. Consequently, with a relatively high rate tilt and the lowest industrial rates in the region, the Oklahoma gas rates are less likely to experience major adjustments than those in the surrounding states. The impact of competition on Oklahoma's electric rates are more difficult to predict generally, but the impact will surely vary among systems.

In restructured competitive markets, the low-cost providers are well positioned competitively, and they should be able to increase their market share regionally. In that regard, the Oklahoma companies are generally in favorable competitive positions although they will face low-cost competition from both inside and outside of the state. However, for similar reasons, low-cost companies also are likely to become acquisition targets for companies looking to expand regionally and to acquire low cost energy sources.

Intrastate Competition

Because they are infrastructure industries, increased efficiencies link emerging intrastate competition in the electric and gas industries with economic development. Of course, with more competitive markets, systems within the state will also be reconfigured as municipal utilities, cooperatives, and investor-owned utilities realign their territories. New suppliers, some offering specialized services, will enter both the gas and electric markets. At the same time, customers and entire communities will reposition themselves within the various service territories. Under whatever impetus, regulatory permission or market forces, there will be a restructuring of Oklahoma's energy industries along least-cost efficiency lines. In some cases this realignment will occur between companies that are similar, such as between two investor-owned utilities. In other cases this realignment will be between companies that have different cost bases such as among municipal, cooperative and investor owned utilities. In those cases, equity issues become increasingly important as territorial boundaries become less clear and because of unequal tax assessment and franchise rights.[25] Equity among competitors is a policy issue for both the State Legislature and the OCC in the emerging competitive environment of the energy industries.

From a policy perspective, the equity among customers in Oklahoma will be an equally significant issue. The competitive forces will provide greater choice in service and will provide customers the flexibility to shape services to their specific needs. However, some customers will benefit more than will others. The larger customers will be the first to benefit from cost-based, market driven rates, and maintaining the rates at competitive levels regionally is an important economic development issue. The larger customers will, in most cases, have superior access to the lower cost power and gas sources.

Since competitive forces will treat large customers more favorably than small customers, there are significant political and policy implications either for the State Legislature or the OCC. Because of these implications, it will be tempting to try to treat these equity issues as though external market forces will not influence them and to delay their impact by delaying moves to deregulation. In the long-run, such a policy would fail. In a less regulated environment, regional market forces will eventually shape the rate results, even within the state. On the other hand, market forces also doom premature policies to expedite deregulation. They either will be overcome by market forces or bypassed making them ineffectual. The regional market forces and the tendencies toward efficiencies will determine the relative rate levels in a less regulated environment.

The Policy Choice

Probably because prices are relatively low, Oklahoma regulators and legislators have, to date, not faced the intense political pressures for restructuring the energy industries as have those in some other states, but news of the initiatives elsewhere is spilling into Oklahoma. More important, the competitive forces in surrounding states as well as from within Oklahoma will shape the industries' restructuring. Giving customers greater freedom of choice and the discipline of the marketplace are persuasive concerns. Maintaining a modern, financially healthy energy infrastructure is equally compelling. As energy industry restructuring has become a national issue, it is an Oklahoma issue also.

Footnotes

[1]The Oklahoma Corporation Commission sponsored "Symposium on Restructuring the Oklahoma Energy Utility Industries" in Oklahoma City in October 1995. See Bob Vandewater, "Caution Urged on Electric Competition, *The Daily Oklahoman,* January 25, 1996, p. 17; Ray Tuttle, "Sparking Competition," *The Tulsa World,* February 4, 1996, p. E-4; and Bob Vandewater, "Business Asks for Electric Choices," *The Daily Oklahoman,* February 9, 1996, p. 14-15. The legislative task force is addressing a broad range of topics, including territorial boundaries, condemnation, annexation, and taxation. For a related study, see Alexander Holmes, Donald A. Murry, Kent W. Olson, and Larkin Warner, *Emerging Issues in Public Service Property Taxation in Oklahoma* (Oklahoma City: Oklahoma 2000, Inc., 1995).

[2]There is a bill in the U.S. Senate, the Electric Competition Bill of 1996, that would expedite deregulation in the electric industry.

[3]A wholesale natural gas or electric sale is a sale for the purposes of resale. Historically, the sale of natural gas or electricity for resale is subject to federal regulatory jurisdiction.

[4]There is a literature called the "Public Interest Theory of Regulation" based on the following assumptions: (1) economic markets are fragile, and (2) government regulation is cost less. See, for example, Richard A. Posner, "Theories of Regulation," *Bell Journal of Economics and Management Science* (1975): 335-36.

[5]*Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[6]The electric and gas companies are capital intensive, and high fixed costs are a characteristic of their cost structure. The allocation of fixed costs to the various categories of service, even when performed with careful professionalism, is somewhat arbitrary. Consequently, there may be sharp differences among customer groups in their charges for the receipt of similar services.

[7]There is an extensive literature demonstrating the theoretical principle that setting rates which are inconsistent with the marginal cost of providing service leads to economic inefficiencies. See, for example, Charles F. Phillips, *The Regulation of Public Utilities: Theory and Practice* (Arlington, VA: Public Utilities Reports, Inc., 1988), 418-25.

[8]This theory goes beyond just the influence of the "regulated" on the "regulator." Proponents of this theory argue that, after a period of time, a regulatory body becomes part of the status quo, and a major purpose of the agency becomes its own survival. See, for example, Emmette S. Redford, *Administration of National Economic Control* (New York: The Macmillan Co., 1952), 386.

[9]Richard A. Posner, "Taxation by Regulation," *Bell Journal of Economics and Management Science* (Spring 1971): 22-50.

[10]Most of the literature on this subject considers the elected officials to be legislators and the regulators to be appointed, as is the case in the federal regulatory bodies. Consequently, the authors consider the indirect effects on the regulators because of the more direct access to the members of the legislature.

[11]George J. Stigler and Claire Friedland, "What Can Regulators Regulate? The Case of Electricity," *The Journal of Law and Economics* 5 (October 1962): 1-16.

[12]R.A. Meyer and H.E. Leland, "The Effectiveness of Utility Regulation," *Review of Economics and Statistics* (November 1980).

[13]H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-53.

[14]Rates set by regulators will remain in effect until they are again changed by regulators. This "regulatory lag" provides an incentive for the regulated company to seek low operating costs during the intervening period. Any cost level above least-cost will result in a short-term reduction in profits. In a similar vein, incentive regulation is a concept that would permit a utility to retain a portion of cost savings from new efficiencies.

[15]The National Association of Regulatory Utility Commissioners polled the state commissions during the summer of 1995 and identified that there were dockets opened, legislative bills introduced, or commission-sponsored seminars held on electric utility restructuring in at least seventeen states. See, also, National Regulatory Research Institute, *Missions, Strategies, and Implementation Steps for State Public Utility Commissions in the Year 2000: Proceedings of the NARUC/NRRI Commissioners Summit* (Columbus, OH: May 1995); and Colorado Public

Utilities Commission Staff, *Changes in the Electricity Industry* (Denver, CO: October, 1994).

[16]Many analysts begin their study of natural gas deregulation with the regulatory decisions at the FERC. That places a wrong emphasis on the market forces, however. In fact, nearly 50 percent of the natural gas flowing on several interstate pipelines was owned by either producers, natural gas distributors, or end users prior to the issuance of FERC Order 436. There were other arrangements, such as the emergency provisions of the Natural Gas Act or the Natural Gas Policy Act, that made this third-party transportation possible.

[17]New York, New Jersey, Maryland, and the District of Columbia are among the jurisdictions that have investigated the opening of the core, small-purchaser retail market of natural gas to nonutility suppliers.

[18]With the introduction of open access, many gas distribution companies faced the threat of bypass by large customers connecting directly to a pipeline system.

[19]As more states experiment with opening the end-use, core market to non-LDC suppliers, that will become a more significant issue in Oklahoma, as well.

[20]The qualifying facilities consisted of cogenerators, which produce steam for an industrial process and use the steam to generate electricity as a joint product, and small power producers. Small power producers are companies that use nonfossil fuel energy sources and renewable energy sources such as wind and water power.

[21]When one utility uses the transmission lines of a second utility to effect a power sale to a third utility, that is called "wheeling." Wheeling power, as the second utility would do in this instance, has the effect of opening the wholesale power market to competition from many generating companies and not just the adjacent utilities.

[22]Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public utilities, 60 FR 17662 at 17668-17675 (April 7, 1995), IV FERC Stats. & Regs., Proposed Regulations 132,514 at 33,057-33,069 (1995).

[23]For more than a year, the California Public Utilities Commission evaluated a proposed restructuring of the state's electric system and recommended separating the operation of the transmission sector completely from the generation and distribution sectors. At the time of this writing, the results of this proposal are uncertain.

[24]Retail wheeling is a feature of the restructured power system in Great Britain and Scotland. The experiences in that system are cited by both advocates and critics of retail wheeling in the U.S.

[25]See Bob Vanderwater, "OG& E Backs Competition in Norman," *The Daily Oklahoman*, Feb. 20, 1996, pp. 10-11 and Alexander Holmes, *op.cit.*

MARKET FORCES, LDC DEREGULATION AND THE EFFICIENCY/EQUITY TRADEOFF

Many analysts begin a study of natural gas restructuring with FERC Order 436, or worse, FERC Order 636. That, however, is a prescription for a misleading interpretation of the changing structure of the natural gas industry. It puts the wrong emphasis on the role of regulation in natural gas market restructuring, especially relative to market forces.

Instead, recognizing that the natural gas industry has been on the path of the present restructuring since the early 1980s, that the movement has been inexorably toward the emergence of competitive markets puts a more accurate emphasis on market forces. It also changes the perspective on the role of regulation--from one of defining market structure and prices to one of accommodating policy to the inevitable forces of the market.

If one accepts, and "recognizes" is probably a more accurate word, that market forces led regulatory action and not the other way around, that provides a basis for evaluating the meaning of these changes in Oklahoma. More important, it also is a basis for choosing regulatory policies that can constructively influence events. It also helps identify the interests of the involved Oklahoma constituencies of producers, customer groups, pipelines, distributors, regulators and others who will have a role in the restructured industry. Interestingly, many of the persons who will be affected by these changes, and even those who will play significant roles in carrying them out, do not yet know it. In sum, the impacts on these many parties is a measure of the effects of restructuring on the state's economy.

EQUITY AND EFFICIENCY

In some respects the direction is inevitable, but the time table and the end results are not. It is also inevitable that some parties will benefit; others will not. Some sectors of the system will grow; others will not. But a policy that focuses on the equity issues of who gains and who loses will be shortsighted. If trying to strike a regulatory bargain between losers and gainers -- and the adjudicative process does this very well -- is the focus of policy, the objective of the endpoint of these changes may be missed entirely. Equity is important, but efficiency is a superior economic objective.

The equity issue is a problem to work through to soften the blow to those who lose from rapid restructuring. The objective is the end point, and, as a major gas producing state, a very efficient natural gas industry that provides an internationally competitive energy source, is not too ambitious. In short, that means that the system should be least-cost, with abundant supplies, priced efficiently, probably with competitive markets for a full range of customer services, some of which are not now available to customers, and enlightened regulation.

Since the natural gas industry is a critical piece of the economic infrastructure, it is important to any regional economy. However, because Oklahoma is a major producing state, with declining market share, marshalling an efficient natural gas industry is a critical step toward achieving the state's economic potential.

A MARKET PERSPECTIVE TO RESTRUCTURING

At the center of natural gas restructuring is replacing administered prices set by federal and state regulators with market forces. Since the field market, with many producers and customers, had an inherent competitive structure, wellhead deregulation was relatively straight forward. Increased supplies caused the field markets to clear at price levels less than the FERC ceiling prices in the early 1980's. That is, the markets decontrolled themselves before the results were ratified by the removal of price controls. By the time the price controls were removed, it was anticlimactic.

In many respects, the open access provisions of FERC Order 636 also followed market forces. Many large customers were purchasing natural gas in the field from producers and transporting gas under various emergency provisions or Local Distribution Companies (LDCs) were purchasing gas in the field as agents of their largest customers in the early and mid 1980s. Pipelines, producers, distributors and customers all were motivated to effect such transactions. Regulatory codification of the market forces expedited the process, but the innate market forces set the direction. Now open access, freedom to withdraw from certificated services or to offer noncertificated services, unbundled services and straight fixed-variable rates have brought market participants, suppliers of services and purchasers, to the transportation services market in sufficient numbers and diversity for a workably competitive market. Of course, these expedited steps have not been taken without cost. The burden of anachronistic investment in supplies and plant, on the one hand, and unreconciled cross-subsidies among customer classes on the other, have been problems to work through. But those are the costs of transition. The bankruptcies and lives hurt by these forces should not be diminished, but the consequences remind us that market forces can be abrupt, and even brutal, at times.

LDC DEREGULATION

The deregulation of the interstate transmission system foreshadowed the changes for LDCs, their customers, the regulators, and in a producing state, for producers, that will accompany the prospective state deregulation of LDCs. For the LDCs deregulation has already meant acquiring gas supplies, arranging reliable transportation and storage services, facing new sources of competition for markets, and coping with gas cost recovery of emergency purchases.

Further state deregulation means open access for the LDC system, removal of some obligations to serve, opportunities for LDCs to engage in some noncertificated business opportunities, competition in unbundled service markets, increased contracting with outside suppliers, redesigned rates, and this list is undoubtedly not complete.

For customers the deregulation of LDCs means increased choices. Open access means alternative supply sources. Unbundled services means alternative suppliers of services and the availability of heretofore unavailable, or even previously unnecessary, services. Rate design will diminish the cross subsidies that have favored the core customers at the expense of the larger non weather-sensitive customers. Pricing closer to or at marginal costs for the non weather-sensitive customers with relatively more elastic demand will induce cost reallocation to the core customers who have a relatively less elastic demand. That in turn will encourage more customers to shift from the core category to the non-core.

For producers, pipelines and alternative suppliers, the deregulation of LDCs will expand their market alternatives. New suppliers of storage and other services will enter the market. Market intermediaries, e.g., brokers, marketers and aggregators offering gas supplies and companies offering services that are new to the industry, such as peak shaving and storage companies, and financial companies offering hedging and price smoothing instruments, will expand services in the end-use market. Market activity will include pipeline capacity in a secondary market that competes with LDC service. LDC deregulation will expand the market alternatives for producers; but it will also complicate their gas marketing. Pipelines and alternative suppliers will develop retail customers behind the LDCs that were formerly protected by the franchise of the utility.

SHIFTING RISKS

The risks of the LDCs have increased already because of changing roles of pipelines from merchants to transporters, but the effects of the risks on cost of capital is probably still not fully comprehended by persons in the industry or recognized by the financial markets. For example, there is empirical evidence that the market has responded to the risk shift from pipelines to distributors, but the financial markets have yet to encounter an LDC's failure to pass high gas costs through to rates in a post-636 environment. This is a new form of regulatory risk. (The attached Figure 1 illustrates the relative changes in common stock price indices for the Moody's Gas Distribution Companies and the Moody's Interstate Pipeline Companies). Paradoxically, increased competition appears to place a burden on regulators to evaluate the market risks from deregulation.

For customers, the risks are likely to differ in the non-core from the core market segments. The core customers will find their supplies of natural gas protected from supply failure by the LDCs that continue to purchase system supply, and by supportive regulatory policies. However, because of less diversity of supplies maintained by the LDC, the core customers will be exposed increasingly to the market price fluctuations. In addition, the risk exposure of the core customers to price variability will increase overtime as more and more customers shift to non-core status and as market intermediaries, e.g., purchasing cooperatives, service companies and brokers, fill the interstices in the market between gas suppliers and customers.

For the non-core transportation customers many have already accommodated to the risks of gas acquisition, gas deliverability, market price fluctuations and contract exposure in exchange for lower gas prices. As LDCs increasingly become open access unbundled providers, the risks will continue to shift to these end users. The non-core gas customers will be the principal customers for the services of brokers, marketers, storage and peak shaving forms, and the companies offering financial instruments that compensate for market fluctuations. Expertise in managing gas supplies, a profession that has developed since the mid 1980s, will now be required by smaller and smaller customers.

STATE POLICIES

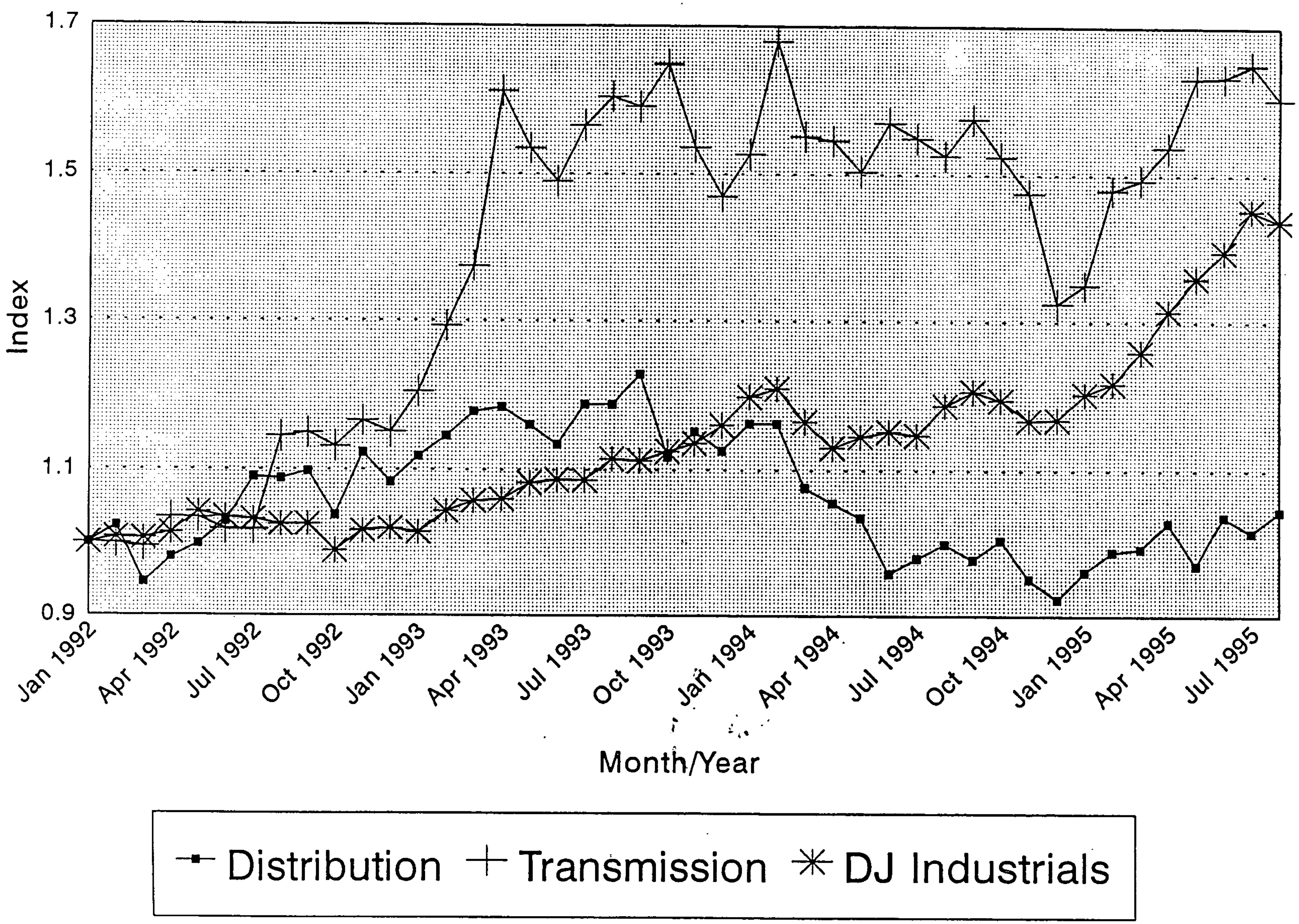
As pipelines moved toward competitive pricing, the gas distributors, situated figuratively in the middle, buffered the rate impact on the core customers. With LDC deregulation, that protection of the core customer is less certain. Nondiscriminatory, open access and unbundled LDC services, with the requisite shift of cross subsidies, will spill the efficiency-equity conflict into the community at large. Because Oklahoma is a major producer of natural gas, many other constituencies also have a stake in LDC restructuring. In this environment, the state regulators will be in the unenviable position of feeling pressures from many directions because of the many affected constituencies; the temptation will be to resist market forces even though they are directed toward more efficient service that would expand the consumption of Oklahoma gas. For the benefit of the state's economy, the task is to resist temptation and to effect a smooth transition.

Donald A. Murry, Ph.D.
Professor of Economics
University of Oklahoma

Symposium on Restructuring in
The Oklahoma Energy Utility Industry
The Oklahoma Corporation Commission
October 17-19, 1995

Comparison of Stock Indices

January 1992 - August 1995



JAN 1 9 1994

American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
Telephone (703) 841-8400

January 12, 1994

MEMORANDUM TO NARUC CONTACT REPRESENTATIVES

Re: Enclosed Merrill Lynch Report Excerpt on ROE

Merrill Lynch just published a report entitled, "Local Natural Gas Distribution Companies -- The Return on Equity Issue." It is my understanding that Merrill Lynch has sent excerpts of that report to the state regulatory community. I have enclosed, for your information, the relevant excerpt which reportedly was sent to the state commissions.

The Merrill Lynch report concludes that if state regulators don't change the way returns on equity are calculated, it is going to be tough for LDCs to compete effectively for capital. According to Merrill Lynch, LDCs are already burdened with an average payout ratio of 77% and cannot easily sustain themselves into the 1990s with falling returns on equity. The report further suggests that state regulators applying outdated valuation models must discard this old utility mind set and realize the far reaching effects of their decisions so that capital will be available at reasonable prices when needed.

A complete copy of this report can be obtained by contacting Merrill Lynch Vice President Donato J. Eassey (713/759-2591) in Houston.

Sincerely,

Eric N. Wise

Eric N. Wise
Counsel

cc: Legal Section Managing Committee

Enclosure

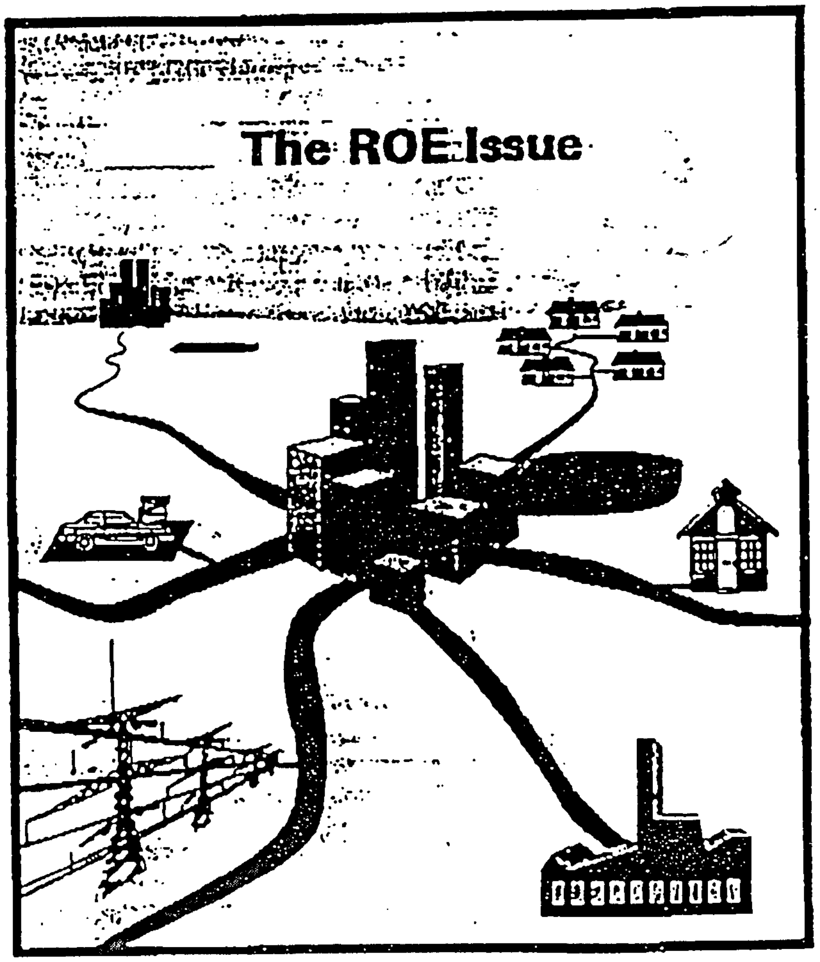
Merrill Lynch

December 3, 1993

United States

Local Natural Gas Distribution Companies

Quarterly Update and Outlook



Donato J. Eassey
Vice President
(713) 759-2591 (Houston)

John E. Olson, CFA
First Vice President
(713) 759-2590 (Houston)

Julianne M. Bass
Industry Analyst
(713) 759-2582 (Houston)

Merrill Lynch & Co.
Global Securities Research & Economics Group
Fundamental Equity Research Department

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Return on Equity Evaluation

Order 636 has had the effect of eliminating the pipeline merchant function as a backstop for LDC's gas supply strategies. Effectively, it eliminated an insurance policy equivalent, and passed the risks of gas costs fully onto the LDC's. Now, return on equity (ROE) has jumped to center stage. What's all the flap about? Is there genuine investment risk or is the concern misplaced and unwarranted? Do the state regulators truly recognize and understand that the fundamentals of the industry have changed? What about the federal administration and its push for more use of domestically produced natural gas? Our analysis suggests that there should be some concern, but overall the risks associated with declining (changing) ROE's present local natural gas utility (LDC) managers, as well as regulators with some new challenges and considerations. We do not believe they will prove to be insurmountable. Further, over the long term LDC's should continue to provide competitive returns with the S & P 500, much like the past 10 years. Why? The secular attractions of gas as a boiler fuel should be reinforced by public and environmental policy making. These should result in decent 5%-10% annual rate base growth. Second, the 10 year long pressure on ROE's, from the falling interest rate cycle, looks about over. Third, we believe state regulators will recognize the shortcomings of current ROE determinations and adjust their decisions accordingly. And, finally diversifications are beginning to make some real contributions.

Table 6 (page 14) provides a regulatory profile of our 18 member LDC universe. The table shows the utilities' theoretical net earnings power based on each LDC's currently approved utility rate base and capital structure. The table also depicts the theoretical EPS sensitivity for each 100 basis point change in ROE as well as each 1% change in rate base. A review should provide greater insight to the specifics associated with declining ROE's.

There is no doubt that declining ROE's in the 1993-1994 era will have to be addressed by both LDC management and state regulators, as well as the financial markets.

We suggest that several LDC's are unique in various regulatory respects. Several attributes should be noted: timing of next rate case; EPS sensitivity to ROE and rate base changes; whether incentive rates have been implemented and/or are under consideration; and whether regulators allow for a prospective or historical test year. Each of these issues along with other important considerations have to be taken into account for evaluation purposes. Generic statements that suggest a decline in ROE will equate to a decline in dividends should be discounted to some extent. There is no doubt that declining ROE's present considerable pressure on EPS. As the table indicates, rate bases must climb by about eight percent on average just to keep pace with a 100 basis point decline in allowed ROE. That is, if nothing else changes. However, there are many other variables, financial markets and flexibility, weather, customer and throughput growth, competing fuel prices and availability, environmental pressures, management's ability to trim or contain costs, and the specific regulatory climate, among others. Many of these would have to remain static for modest changes in ROE's to have a significant impact on EPS and dividend payout ratios. The very dynamics of many of these issues transcend the likelihood of a significant decline in earnings power. As always, there are exceptions.

There is no doubt that declining ROE's in the 1993-1994 era will have to be addressed by both LDC management and state regulators, as well as the financial markets. When Order 636 was issued (July 31, 1991-April 8,1992) the general consensus was that state regulators would recognize and consider the new market realities facing LDCs when rate cases came under review. These new market realities generally translated into greater operating and costs recovery risks. The "one stop shopping" which the LDC historically relied on is

We believe a more representative ROE cap should be based on a five year rolling average of the S&P 500 return on equity instead of interest rate trends.

just that, history. With the advent of Order 636 pipelines today are little more than conduits. Their natural aggregating prowess and shock absorbing abilities are distant echoes. As a result, LDCs had to gear up to access and contract for their own natural gas supplies, transportation and storage requirements. Though untested as yet, most LDCs appear to be prepared for the new market realities. However, it appears not all state regulators are prepared to change. Many appear to still be viewing and treating LDCs as they have in the past; without regard to market realities which have fundamentally changed. If all LDCs were private non-profit companies it would matter little what state regulators did. However, LDCs compete for capital just like any other public company. And they compete for equity capital primarily against the S & P 500, and not bond markets. In past years when risks were primarily weather related, LDCs were able to effectively compete in the market in general, even though the earnings trend were generally on only a modest upward tract. This was due to the perceived dividend stability and overall security of earnings.

Although we believe LDC managements are aggressively discarding much of the old utility mentality to meet the new challenges of 636, we have not yet seen state regulators rising to the occasion. This is nowhere clearer than on the rate of return front. Here regulators are still using both academic and outdated valuation models to derive ROE's that reflect interest rate trends rather than competitive market realities. In our opinion, Regulators must begin to realize that adding a yield premium to the long bond simply will not attract capital to an industry which has such a genuine and tremendous need for capital. The LDC group is already burdened with 77% average payout ratios (66%-100% range) and cannot easily sustain itself into the '90's with a climate of falling ROE's. In our opinion, if state regulators don't change the way ROE's are calculated, it is going to be tough for LDC's to compete effectively for capital.

From an analyst's perspective the federal energy agenda looks far more promising for gas than at the state level. The Administration appears to be focusing on and supporting the use of natural gas. We know of few other single efforts which would hit on so many fronts and have such extensive far reaching positive domestic effects as natural gas. Benefits of increased natural gas usage would include: environmental positives, lessening the nation's dependence on foreign oil, putting a dent in the trade deficit, improving overall energy efficiencies, reducing consumers bills' (both household and transportation, as natural gas is about 2/3s the cost of gasoline); and encouraging more efficient use of existing underutilized capacity. Even at the FERC level, Order 636 and its powerful rate design, along with healthily equity ratios, and 12% or better ROE's provide a solid contribution to a positive investing outlook. However, some state regulators appear to be much more nearsighted. Recent decisions on Washington Energy and to a lesser extent Atlanta Gas Light are good examples as to why regulators should not base ROE's on a snapshot of the long bond in today's new untested and uncertain operating environment. Not to mention that consumers benefit on the debt side of the ledger from lower debt costs as a result of declining interest rates. We believe a more representative ROE cap should be based on a five year rolling average of the S&P 500 average ROE. The result would allow LDC's to compete effectively and more appropriately with market-based equity returns, and not simply the long bond. To enhance the ROE cap a sliding scale customer sharing mechanism would further insure efficiencies. While longer term in nature, this type of ROE determination would send a powerful message to the financial markets which the natural gas industry is so dependent upon. Investors want to buy an equity for both growth and return. They don't want a mere bond substitute. Moreover yields have been built

Why would an investor consider a utility security at all versus a bond when risks have shifted so much?

over the years on a totally different set of operating and market fundamentals. In today's riskier LDC environment, to arbitrarily set ROE's based on the long bond plus some yield premium seems likely to stifle future growth by chilling the investing climate. The ripple effects ultimately can be dramatic. In the wake of the Washington Energy ruling, the dividend was cut: the bond ratings were cut; all charitable contributions disappeared; corporate travel was disallowed; and its unregulated businesses are being cannibalized to raise cash. Why would an investor consider a utility security at all versus a bond when risks have shifted so much? They may not, which could have a snowballing negative impact. Not all state regulators appear so nearsighted, nor are investors. We have seen some progressive decisions and indications from New York, Michigan, New Jersey, Pennsylvania, Alabama; and there are some positive rumblings in California. Moreover, while the Georgia commission lowered ATG's ROE, the Commission allows for a prospective capital structure which helped mitigate the impact of the ROE decline. So, there are some rays of hope from an investment perspective. However, in our view, until regulators become more sensitive to market realities, LDC investors will have to be more vigilant and selective than ever before.

We think this group, with some exceptions, will remain attractive. The flap over declining ROE's seems likely to subside as state regulators come to grips with the market realities (both financial and operational) facing LDCs. While the gas industry will always have its share of uncertainty, it is still one of the soundest and fastest growing sectors of the energy industry. Indeed, never before has there been more of an incentive for LDC's to "fill the trough" (i.e. unused capacity during the off season). As that summer trough is filled, all segments of the industry should benefit and prosper. However, it will take a great deal of new capital to maintain the integrity of existing systems and allow for growth to meet demand expectations. If regulators continue to reduce ROE's in tandem with interest rates, then earnings, yields and credit ratings will all suffer, and more Washington Energy situations could repeat themselves. All of this of course would detract from the ability to raise capital. However, we remain hopeful that state regulators which are still applying outdated valuation models will discard their old utility mind set and realize the far reaching effects of their decisions so that capital will be available at reasonable prices when needed.

Table 8

Analysis of Return on Equity

Distributors	Current rates effective Effective/Next filing date*	Allowed ROE	Allowed Rate Base ($MM)	Allowed Equity Component	Theoretical Utility Earnings ($MM)	Theoretical Utility (Only) EPS	Consolidated 1994 EPSE	Theoretical EPS Sensitivity (Each 100 Basis Pts (ROE) = $/share)	Theoretical EPS Sensitivity (Each 100 Basis Pts (ROE) = %/share)	Theoretical EPS Sensitivity (Each 1% change in RB = $/share)	Theoretical EPS Sensitivity (an 8% change in RB = $/share)	Incentive Rates Current/Pending	Test Year Historical or Prospective
AL Gas Light	11-91 & 10-93/N/A	11.08%	$1,156.30	43.11%	$55.20	$2.23	$2.25	$0.20	9.03%	$0.02	$0.10	Yes - Minor/N/A	Prospective
Brooklyn Union	10-01-93/11-1-93	12.10%	1,217.00	50.10%	73.78	1.60	1.80	0.13	8.26%	0.02	0.13	Yes/Yes	Prospective
MCN Corp.**	4-90/1-94	15.00%	1,025.00	34.97%	53.77	1.83	2.50	0.12	6.67%	0.02	0.15	Yes/Yes	Combination
Nat'l Fuel Gas	3&7-93/8-93 & 12-94	12.08%	834.00	50.00%	50.37	1.38	2.40	0.11	8.28%	0.01	0.11	No/Under Review	Prospective
NICOR	1-88/N/A	12.75%	1,029.60	55.00%	72.20	1.32	2.05	0.10	7.84%	0.01	0.11	No/No	Combination
ONEOK	3-5-92/3-94	12.12%	528.00	54.76%	35.06	1.32	1.30	0.11	8.25%	0.01	0.11	No/No	Historical
Pacific Ent	12-31-93/Pending	10.86%	3,000.00	48.90%	182.47	1.82	1.85	0.17	9.21%	0.02	0.15	No/No	Prospective
Peoples Energy	11-91 & 10-92/N/A	12.31%	1,166.90	55.04%	79.03	2.27	2.15	0.16	8.12%	0.02	0.18	No/No	Prospective
UGI Corp	1984/1994	12.00%	412.00	48.30%	23.88	0.75	1.65	0.08	8.33%	0.01	0.08	No/No	Prospective
Wash. Gas Lt.	8&10-93 & 7-90/N/A	12.08%	820.00	54.44%	60.41	2.92	2.65	0.24	8.29%	0.03	0.23	No/No	Historical
Simple Average		12.24%	$1,128.79	49.25%	$85.62	$1.74	$2.06	$0.14	8.23%	$0.02	$0.14		
Distributors (X)													
Atmos Energy	9 & 11-92 & 5-91/N/A	12.50%	$206.00	46.16%	$11.89	$1.50	$1.90	$0.13	8.00%	$0.02	$0.13	No/No	Historical
Indiana Energy	10-28-92/4-8-94	12.25%	486.00	54.00%	32.15	1.43	1.37	0.12	8.16%	0.01	0.11	No/Under Review	Historical
New Jersey Res.	6-24-92/Pending	12.20%	369.00	38.80%	18.41	1.11	1.85	0.09	8.20%	0.01	0.09	No/Pending	Historical
NW Nat'l Gas	1989 & 1986/N/A	13.25%	427.77	45.40%	25.73	1.96	2.50	0.15	7.55%	0.02	0.16	Yes/Yes	Historical
NUI Corporation	9 & 9-91/N/A	12.56%	246.80	53.68%	10.64	1.84	1.85	0.15	7.96%	0.02	0.15	No/Under Review	Hist (NJ) Prosp (FL)
Piedmont Nat'l	7&11-91/Pending & 4-94	12.39%	483.10	51.28%	31.32	1.20	1.63	0.10	8.07%	0.01	0.10	No/No	Hist (SC) Prosp (TN)
Pub. Svc. of NC	11-1-91/Spring '94	12.90%	281.00	47.54%	16.01	1.00	1.00	0.04	7.75%	0.01	0.08	No/Under Review	Historical
Washington En.	10-6-93/11-93	10.50%	484.00	44.00%	22.34	0.96	1.00	0.09	9.52%	0.01	0.08	No/No	Modified - Historical
Simple Average		12.32%	$374.21	47.61%	$21.81	$1.39	$1.63	$0.11	8.15%	$0.01	$0.11		

Note: We have estimated and weighted certain allowed ROEs and allowed return on equity for those companies which have "black box" settlements and/or multiple regulatory jurisdictions.
*Pending = awaiting decision; N/A = not available or no filing anticipated
**MCN allowed ROE is 11.8% plus various flexible rates which is estimated will bring the allowed ROE to about 15%

Table 7

Latest Balance Sheet Data
($ millions)

	Date Re-ported	Cash & Equiv.	S-T Debt	Net Working Capital	Long-Term Debt	+ Preferreds	= L-T Leverage	+ Common Equity	= Total Leverage	% Leverage
Local Distribution Cos.										
Al. Gas Lt.	09/30	$3.3	$257.4	($162.3)	$376.0	$58.7	$433.7	$482.0	$925.7	46.9%
Brooklyn Un.	06/30	92.9	0.0	155.2	692.7	7.5	700.2	692.7	1,392.9	50.3
MCN Corp.	09/30	8.8	235.0	(46.2)	498.7	5.6	504.3	451.7	956.0	52.8
Nat'l Fuel Gas	06/30	88.1	224.1	(143.6)	448.4	–	448.4	747.6	1,196.0	37.5
NICOR	09/30	48.4	171.9	(58.3)	450.3	16.7	467.0	699.7	1,166.7	40.0
ONEOK	08/31	9.7	38.1	42.4	375.9	9.0	384.9	363.1	748.0	51.5
Pacific Ent.	03/31	420.0	165.0	165.0	1,638.0	453.0	2,091.0	747.0	2,838.0	73.7
Peoples	09/30	n/a	n/a	97.4	528.1	1.8	529.8	628.5	1,158.3	45.7
UGI Corp.	03/31	65.4	45.3	25.0	353.5	34.2	387.8	409.5	797.2	48.6
Wash. Gas Lt.	09/30	4.9	38.5	(18.3)	347.7	28.5	376.2	347.7	723.9	52.0
Total		$741.5	$1,178.2	$58.0	$5,706.3	$615.0	$8,323.3	$5,579.5	$11,902.8	53.1%
Local Distribution Cos. (II)										
Atmos Energy	06/30	$2.3	$20.3	($14.0)	$85.3	$0.0	$85.3	$115.9	$201.2	42.4%
Indiana Energy	06/30	38.8	10.0	8.2	174.9	0.0	174.9	268.5	443.4	39.4
New Jersey Res.	06/30	2.4	10.1	(8.3)	273.0	22.3	295.3	255.7	551.0	53.6
Northwest Nat'l Gas	06/30	4.8	27.2	(16.6)	253.8	45.9	299.6	261.0	560.7	53.4
NUI Corporation	06/30	3.5	53.9	(66.6)	131.5	0.0	131.5	116.9	248.5	52.9
Piedmont Nat'l	04/30	n/a	n/a	(59.9)	193.0	–	193.0	306.0	499.0	38.7
Pub. Service of NC	06/30	15.0	15.5	(11.0)	129.5	–	129.5	130.2	259.7	49.9
Washington Energy	06/30	n/a	133.8	(1.1)	278.4	27.3	303.7	348.8	650.5	46.7
Total		$66.9	$270.9	($171.2)	$1,517.3	$95.5	$1,612.9	$1,801.0	$3,413.9	47.2%

Table 8

Total Returns By Company, 1988 - November 30, 1993

[illegible]	Percent Total Return						Percent Price Change						Percent Yield					
	Nov. 30, 1993	1992	1991	1990	1989	1988	1993 YTD	1992	1991	1990	1989	1988	1993 YTD	1992	1991	1990	1989	1988
[illegible]	1.8	8.7	26.8	6.8	27.8	25.6	(4.0)	3.1	20.1	0.4	20.3	17.4	5.5	5.7	6.7	6.5	7.4	8.2
Brooklyn Un.	22.8	16.8	9.6	(2.4)	43.6	15.4	17.0	10.3	3.0	(8.2)	38.0	7.4	5.8	6.5	6.5	5.6	7.6	8.0
MCN Corp.	18.1	33.6	21.0	(1.2)	34.4	—	12.6	28.7	13.4	(8.0)	25.8	—	5.8	6.9	7.6	6.8	8.5	—
Nat'l Fuel Gas	18.4	28.5	9.3	(9.1)	52.2	20.7	13.1	20.4	3.2	(14.0)	45.4	13.4	5.2	6.1	6.1	4.9	6.7	7.3
NICOR	16.6	14.5	8.5	0.3	53.6	42.5	10.6	9.3	3.4	(4.3)	47.2	34.4	4.9	5.2	5.1	4.6	6.4	8.1
ONEOK	17.4	15.3	20.0	(2.6)	75.7	16.5	11.5	8.9	14.4	(7.6)	68.9	12.7	5.9	6.4	5.6	4.7	6.9	3.8
[illegible]	[illegible]	(29.0)	(25.7)	(16.1)	43.9	(17.6)	37.5	(29.0)	(32.6)	(23.0)	34.7	(24.6)	6.4	0.0	6.7	6.9	9.3	7.0
[illegible]	[illegible]	[illegible]	20.0	(1.8)	42.1	34.2	(3.3)	13.1	12.7	(8.2)	33.8	28.2	5.9	6.6	7.3	6.4	8.3	10.0
[illegible]	[illegible]	[illegible]	[illegible]	(9.0)	36.9	24.4	(9.6)	20.5	24.8	(15.9)	28.6	17.2	5.5	6.6	7.6	6.1	7.4	8.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5.8	12.0	16.9	(8.3)	27.3	10.8	5.8	6.2	7.1	6.4	7.8	8.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7.5	8.9	5.2	(10.6)	34.3	4.1	5.6	5.6	6.6	5.9	7.6	7.7
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10.6	2.2	38.3	(7.0)	10.0	32.7	5.6	5.6	7.3	6.5	7.0	8.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	15.0	3.2	17.0	9.9	32.0	33.0	6.4	6.1	6.9	6.3	6.8	8.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8.1	19.6	10.9	(12.5)	18.5	7.6	6.2	7.5	8.2	7.0	7.8	7.9
[illegible]	[illegible]	8.1	18.2	9.6	26.0	17.9	22.6	(0.8)	11.7	3.0	18.3	9.7	6.2	8.0	8.8	6.6	7.6	8.2
[illegible]	[illegible]	56.0	(2.2)	13.6	(2.8)	8.2	8.8	45.6	(10.7)	4.9	(10.6)	(2.4)	6.6	9.4	8.4	8.7	7.8	7.8
[illegible]	[illegible]	20.8	19.8	10.4	21.8	33.4	10.4	15.3	13.6	4.5	15.4	25.6	5.1	5.5	8.0	6.0	6.6	7.6
[illegible]	[illegible]	17.4	18.8	4.3	16.1	26.4	(8.9)	61.0	11.7	(2.3)	8.3	17.5	4.4	6.4	6.7	6.6	6.7	7.6
[illegible]	[illegible]	4.0	18.8	(4.0)	68.9	8.3	(14.4)	(2.2)	11.9	(10.1)	59.5	(10.9)	4.9	6.3	7.0	6.1	9.4	8.1
Sample Avg.	13.4	19.8	20.0	6.1	25.2	20.8	7.6	13.0	12.8	(1.9)	17.3	12.1	5.6	6.7	7.4	7.0	8.0	8.5

ATG is virtually a pure Natural Gas Utility. It has a $1.2 billion rate base with an average allowed ROE of 11.08%; Regulated Capital Structure: 43.11% equity 56.89% debt; Market Capital $918 mm; Average daily trading volume: 44,685; Institutional ownership: 19%. Our Investment Recommendation B-2-2-7.

Table 8

Atlanta Gas Light Company

Summary Investment Profiles, F1990-F1994E

(per share, except where noted)

	F1990	F1991	F1992	F1993E	F1994E	F1995E
Per share						
Operating EPS	$2.02	$2.07	$2.26	$2.16	$2.25	$2.30
Unusual items	0.00	0.00	0.00	0.00	0.00	0.00
Reported Earnings	$2.02	$2.07	$2.26	$2.16	$2.25	$2.30
Dividend	1.96	2.04	2.06	2.08	2.08	2.10
Cash flow from operations	4.51	5.13	5.35	4.97	4.74	4.93
Book Value	17.93	18.84	19.40	19.80	19.97	20.16
NWC	(3.46)	(2.49)	(9.61)	(0.73)	(3.32)	(4.01)
Percent						
Payout	96.9%	98.4%	91.3%	96.4%	92.6%	91.4%
Return on equity	11.3	11.0	11.6	10.9	11.2	11.4
L/T Leverage	53.6	51.3	51.2	52.0	50.5	51.0
Total Leverage	52.2	51.2	41.9	52.8	50.3	51.6
Taxes	33.9	34.7	31.6	33.0	35.0	35.0
Avg. Yearend shares	21.9	23.3	24.1	24.6	26.0	26.1
Quarterly EPS						
Q1	$0.98	$1.05	$0.88	$0.87A	$0.90	$0.95
Q2	1.63	1.47	1.79	1.79A	1.90	1.95
Q3	(0.11)	(0.11)	(0.06)	(0.14A)	(0.13)	(0.12)
Q4	(0.46)	(0.30)	(0.31)	(0.34A)	(0.42)	(0.46)
Year	2.02	2.07	2.26	2.16	2.25	2.30
Annual EPS Growth Rate	6.30%	2.48%	8.89%	-4.43%	4.07%	2.31%
Dividend paid per share						
Q1	$0.49	$0.51	$0.51	$0.52	$0.52	$0.53
Q2	0.49	0.51	0.51	0.52	0.52	0.53
Q3	0.49	0.51	0.52	0.52	0.52	0.53
Q4	0.49	0.51	0.52	0.52	0.52	0.53
Year	$1.96	$2.04	$2.06	$2.08	$2.08	$2.10
Stock prices (calendar year)				Y-T-D		
High	$32.13	$37.63	$39.00	$42.50	—	—
Low	$29.75	$29.75	$30.25	$36.50		
Close	$30.60	$36.63	$37.75	$37.00		
% Total Return				Y-T-D		
Price Change	—	20.1%	3.1%	-2.0%	—	—
Yield	—	5.6%	5.5%	5.6%		
Total Return	—	25.7%	8.5%	3.6%		

The financial outlook for LDCs and pipelines

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C.H. GUERNSEY CO.

by Donald D. Dufresne

Climaxed by the creation and implementation of Order No. 636, the last few years have been characterized by substantial regulatory change.

Despite the fact that the pipelines have received a great deal of attention throughout this time frame, perhaps due to the Chapter 11 filing of Columbia Gas and speculation that Transco and Arkla might follow in Columbia's footsteps, the local distribution companies will certainly feel the greatest impact of Order No. 636 and other changing industry fundamentals.

The risks that challenge the LDCs have grown beyond the comprehension for many analysts, portfolio managers, managements, local regulatory agencies, FERC, and members of Congress.

LDCs are now responsible for building their own gas supplies, and they have received very little guidance from state regulators as to what is apropos, and what is not. It sets the stage for the kind of Monday morning quarterbacking that many PUCs delight in.

Building a supply portfolio and avoiding disruptions may be tougher for many LDCs than we might imagine, especially if the industry is challenged by a difficult winter. Many LDCs do not understand the nuances of the pipeline systems, or the supply basins that they utilize, as well as the pipelines do. Unexpected bottlenecks and well freeze-ups for instance could disrupt supplies for a period of time. Without a system supply to fall back on, or significant storage working gas for that matter, it may be difficult for pipelines to provide a much needed bail out.

Most other risks that we should be concerned with, both non-636 and 636 risks, will place a significant amount of pressure under the cost structure of many LDCs, and will have a significant impact on consumer bills

1. SFV rates — due to stiff demand charges, LDC payments to pipelines will rise relative to those under modified fixed-variable.

2. Transition costs — the pipelines will attempt to pass on approximately \$3 to \$5 billion in transition costs to LDCs.

3. Bypass — the Atlanta Gas Light/Arcadian/Southern Natural episode offers a great example of how shareholders, and eventually ratepayers, are left holding the bag. The net impact on ATG was \$4 million, and that will be passed on to the ratepay-ers.

4. Take-or-pay — yes, TOP could come back to haunt us. LDCs are being asked to sign such contracts in direct purchase arrangements with producers We are beginning to be concerned about the demand outlook for natural gas, and TOP liabilities could be a reality once again.

5. Escalating wellhead prices — wellhead prices have more than doubled in the past 18 months.

6. Storage — the LDCs will own the gas in storage which will have to be financed. Additional debt financings for this purpose could affect debt ratings.

What is amazing about these developments is that state PUCs are blind to the fact that LDC risks have skyrocketed and current returns are not commensurate with the

risks that we have just discussedThe current trend is frightening.

Recently allowed LDC ROE include:

1. Southwest Gas was awarded a 10.75% return on equity.

2. Washington Natural Gas was awarded a 10.5% return on equity, which translates into a $17 million, or a 5% rate reduction. Regardless what the Washington PUC says, the quality of service will suffer, and the PUC should bear the blame, not Washington Natural.

3. Atlanta Gas Light was awarded a 11.0% return on equity, a 1.1% rate increase. This is the third consecutive bashing that the Georgia commission has given to the company.

The only risk that the PUCs appear to be focusing on is the long bond. With the long bond yielding 6% or less, the result has been the disastrous returns cited above. The risks that we discussed earlier apparently do enter into the determination of a just and reasonable rate of return.

We are afraid of monkey-see, monkey-do rate making. Other PUCs only need a little justification or a slight nudge to reduce returns, and we would not be surprised to see additional awards in the 10 to 11% range.

Today's LDCs dividends and payout ratios were not made for these type returns, so dividend cuts are sure to come if this trend continues. Southwest Gas has already cut its dividend for other reasons, but Washington Energy Company appears to have little choice. Atlanta Gas Light cannot stand another ravishing from its commission, or tough decisions may have to be made.

These are the probable results, if dividend cuts become a major threat to the LDCs:

1. The worst case is that companies would be shut out of the equity market. The best case is that the cost of equity capital to LDCs will rise substantially.

2. The quality of service will be impaired.

3. Natural gas demand growth will slow. LDCs will not have the financial ability to accommodate growth.

It is time for local regulators to wake up and recognize that the consumer is not their only responsibility. They also have a responsibility to the shareholders, managements, and employees of these companies.

In the federal arena

The FERC commissioners had little choice but to endorse Order No. 636, regardless of their true feelings. Realistically, how do you unscramble this egg at this point? However, pressures on FERC to substantially alter Order 636 could mount if LDCs and consumers scream loud enough. Congress could intensify those pressures. Representative Sharp (D-IN) is listening.

The outlook for the pipelines is mixed. Although pipelines still face some risks under Order No. 636, the level of risk for the pipelines has declined by a significant amount. Straight fixed variable ratemaking is as close to a return guarantee as we can get, and, as we said before, long-term rates are a their lowest level.

Pipeline risks are not as great as those faced by the LDCs. Yet, in contrast, allowed pipeline ROEs are in the 13 to 15% range. We are afraid that these returns will have to drop in recognition of a reduced level of risk. One could argue that they should be below the returns allowed the LDCs given the shift in risk that has occurred. We recognize that pipelines no longer have to file periodic rate cases under Order 636; however, as a result of LDC and consumer pressures, it is likely that FERC will effect periodic rate reviews to protect the consumer.

Under Order No. 636, rate base growth is the key to earnings growth. Yet, the pipeline industry is a mature industry with little room for significant expansion. Where can significant construction projects be justified? (That is, California is glutted with pipeline capacity, as is the Midwest. The Northeast is risky as a result of a slow economy and a glut of IPPs. Mexico may not import as much gas as originally thought.)

LDCs will survey pipeline expansion projects very carefully. They will probably lobby for incremental pricing to check questionable pipeline projects. It is possible that the new FERC, which appears to be consumer-oriented, could stymie attempts at bypass.

Pipelines will also attempt to grow non-regulated merchant services. However, we believe many pipelines have overestimated the potential and underestimated the risk of this business. The business will probably be dominated by a few players such as the Natural Gas Clearinghouse, Enron, Coastal Corp., and several of the major oil companies such as Chevron. ❑

Donald D Dufresne represent...

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 17
Witness: Donald A. Murry

Data Request:

The capital structure, which contains 50.24% equity, 40.36% long-term debt, and 9.40% short-term debt, is different from the current capital structure of Atmos. The 9/30/99 13-month average capital structure contains 42.7% equity, 44.5% long-term debt and 12.8% short-term debt. Which of these capital structures do you believe the financial market assesses when evaluating the risk of Atmos -- the actual one or some hypothetical one? Please explain your answer.

Response:

Investors who wish to determine the capital structure of Atmos will have available to them a variety of reputable estimates. It is Dr. Murry's opinion that in most cases investors would choose a current or forecasted capital structure as a more relevant measure of a company's capital structure than a 13-month average. A forecasted capital structure at a point in time is not a "hypothetical" capital structure. It is an estimate of what the capital structure will be at some time in the future, and analysts will use forecasted capital structure in their evaluation of a security's value.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 18.a.
Witness: Donald A. Murry

Data Request:

Refer to page 20, line 2 of your pre-filed testimony. Here you indicate that the cost of equity for Atmos is 11.31% as shown in Schedule DAM-17. Your analysis shows:

	Atmos		Moody's Companies	
	High	Low	High	Low
Schedule DAM-6	8.62%	7.63%	7.62%	6.39%
Schedule DAM-7	9.13%	7.68%	7.90%	6.71%
Schedule DAM-8	9.09%	8.97%	7.63%	7.49%
Schedule DAM-9	15.77%	14.78%	10.95%	9.72%
Schedule DAM-10	15.77%	12.28%	10.29%	8.40%
Schedule DAM-11	16.28%	14.83%	11.23%	10.03%
Schedule DAM-12	16.28%	12.33%	10.57%	8.71%
Schedule DAM 13	16.25%	16.12%	10.95%	10.81%
Schedule DAM-14	16.25%	13.62%	10.29%	9.49%

a. Why did you ignore all of the data in your DCF analysis in forming your recommendation?

Response:

Dr. Murry did not ignore data cited in the question in his DCF analysis when performing his ROE recommendation. The 11.31% cited in the question is from a CAPM analysis. As the testimony indicates, the 11.31% is the estimate using one method only. Other quoted estimates are from various DCF analyses. Dr. Murry evaluated and considered the implications of these various calculations using different analytical approaches.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 18.b.
Witness: Donald A. Murry

Data Request:

b. Why did you ignore all of the data from your Moody's companies in the DCF analysis in forming your recommendation?

Response:

Please see the Response to AG1-18a.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 18.c.
Witness: Donald A. Murry

Data Request:

c. Why did you ignore all of the DCF analysis and your finding on page 20 at line7 to make a recommendation for the cost of equity from 12.0% to 12.5% in Schedule DAM-22?

Response:

Please see the Response to AG1-18a.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 19
Witness: Donald A. Murry

Data Request:

Refer to page 20, line 5 where you state that, "if Western Kentucky were raising capital on its own." Under what circumstances could Western Kentucky Gas Company, as a division of Atmos, raise capital on its own?

Response:

As an unincorporated division of Atmos, Western cannot raise capital on its own. Western would have to establish itself as a separate corporate identity in order to raise capital on its own.

Data Request:

20. Refer to page 4 line 5 of your testimony where you refer to Atmos peer companies. Please provide the names of the companies that you consider to be Atmos peer companies.

Response:

The reference to peer companies on page 4, line 5, of Mr. Reddy's testimony relates to a March 1, 1999 research report on Atmos Energy Corp. published by the brokerage firm of A.G. Edwards. In that report, A.G. Edwards states:

> "As of September 30, 1998 common equity represented approximately 44% of total capitalization (including current maturities of long-term debt and short-term debt) which is below *ATO's peer group average of 51%*. We would note, however, positive efforts on the part of management to improve the balance sheet over the last several quarters through asset sales and debt refinancing." (Italics added.)

In that same research report, A.G. Edwards lists the following companies for peer comparisons to Atmos: AGL Resources, Indiana Energy, Inc., Laclede Gas, New Jersey Resources, NICOR, Inc., Northwest Natural Gas, Peoples Energy, Piedmont Natural Gas, and Washington Gas Light.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 21
Witness: John P. Reddy

Data Request:

21. Refer to page 4 line 5 of your testimony where you refer to Atmos peer companies. What criteria did you use to select Atmos peer companies?

Response:

As explained in the response to DR 20, the peer companies referenced on page 4, line 5 of Mr. Reddy's testimony are those used by A.G. Edwards and are referenced in Mr. Reddy's testimony for the limited purpose of comparing Atmos' capital ratios to a representative sample of peer companies.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 22
Witness: John P. Reddy

Data Request:

22. Refer to page 4, lines 5 and 6 of your testimony. You indicate that a 50% debt and 50% equity structure is consistent with the objective of maintaining an "A" credit rating on senior debt. Please provide a copy of the rating agency criteria which indicates that a 50/50 capital structure will assist in maintaining an "A" rated bond.

Response:

Standard & Poors credit criteria for rating Public Utility Debt can be found at S&P's website, www.standardandpoors.com/ratings. For gas LDC's like Atmos with a Business Position ranking of "3", the Total Debt to Total Capital ratio for an "A" rating is between 47.5% and 53.0%.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 23
Witness: John P. Reddy

Data Request:

23. Refer to page 5, lines 1-4 of your testimony. You describe a reserve of $20 million ($13 million after tax) to account for merger and integration costs associated with the United Cities merger.

a. Do you anticipate the entire amount of the reserve will be used (sic) the merger costs?

b. Please provide the projected timetable for costing the reserve in an amount/quarter/fiscal year format.

Response:

a. A general reserve of $20 million was established to account for costs that might not be recovered through rates. At this early date in the rate proceeding processes, it is not known how much of this reserve will be needed. This will only be known as rate proceedings are finalized.

b. Currently, the reserve is being amortized on the same basis as the amortization of merger and integration costs (i.e., over 7 years).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 24
Witness: John P. Reddy

Data Request:

24. Refer to page 5, lines 5-8 of your testimony. You indicate that warmer than normal weather has reduced retained earnings. Refer to page 26 of Atmos Energy Corporation Annual Report which shows the consolidated statement of shareholders equity. Please indicate where the weather related losses caused a reduction to retained earnings.

Response:

See page 48 of the Atmos Energy Corporation Annual Report, under the heading "Effects of Weather" where it states: "Normal weather conditions would have added $.11 per share to net income in 1998." Using 30,031,000 average shares of common stock outstanding during 1998, net income and retained earnings would have been $3.3 million higher with normal weather.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 25
Witness: John P. Reddy

Data Request:

25. Refer to page 6, lines 12-16 and to page 4, line 3 of your testimony. Please reconcile the stated 50% debt and 50% equity capital structure objective with the summary of the projected capital structures shown on lines 11-17 of page 6.

Response:

Please refer to the response to KPSC Data Request dated July 16, 1999, Item 13 a and b and to KPSC Data Request #2 dated August 19, 1999, Item 11 a.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 26
Witness: Gruber

Data Request:

Reference Mr. Gruber's testimony at page 6, lines 20-21. Please provide budgeted and forecasted O&M expenses for whatever time periods such estimates exist. Please also provide 1999 actual O&M.

Response:

See Supplemental Response to KPSC #1 DR Item 6, Exhibit A.

Fiscal Year 1999 is currently projected at $22,760,106 based upon the most recent 10 months actual plus 2 months budgeted.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 27, a - b
Witness: Gary Smith

Data Request:

27. Refer to Mr. Gruber's testimony on page 7, line 19.

    a. Explain exactly how, in Mr. Gruber's opinion, industrial margins subsidize residential rates.

    b. Quantify the amount of alleged subsidization that Mr. Gruber believes exists in the proposed test year. (And any other recent actual time period that Mr. Gruber may have in mind.) Please provide workpapers detailing the requested quantification.

Response:

Mr. Smith will address the questions posed above. Mr. Gruber's statement in the referenced testimony is in recognition of the adverse impact of current rate structures on the Company's financial performance.

a. The term "subsidize", in this context, refers to the state of general effectiveness of the Company's rate design among various customer classes. Western's view that industrial margins subsidize residential margins is derived from its experience in a historical perspective. Western's experience, in general, has been that its rate structures have produced certain undesirable results, namely the inability to sustain financial integrity without seeking rate increases every three to five years.

   In regard to individual customer classes, we have noted the competitive environment in which Western competes, and the necessity of discounting tariff rates to retain certain bypass vulnerable accounts. Residential class rates produce inadequate returns on the extension of service to new residential customers.

   Recognizing these circumstances and their impact on the Company's financial integrity have led Western to the opinion of industrial subsidization of the residential class.

b. Please refer to the response to this, the First AG Data Request, Item 45.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 28
Witness: Gary Smith

Data Request:

28. Please provide the number of industrial customers for each year 1990 through present. Indicate basis of customer count (average, year-end, number of meters, etc.)

Response:

The following table provides the number of industrial sales and transportation customers from 1990 through present. The information resource is Western's operating and revenue statistics and is reported on the basis of the 12-month average customer count.

Fiscal Year	Industrial Sales	Transportation	Total Ind. Sales and Transportation
1990	266	80	346
1991	274	88	362
1992	297	63	360
1993	305	62	367
1994	347	41	388
1995	369	23	392
1996	335	33	368
1997	316	77	393
1998	295	95	390
1999 *	281	110	391

* - 9-month average, through June 1999.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 29
Witness: Gruber

Data Request:

Reference Mr. Gruber's testimony at page 8, line 13. Provide the numerical support relied on by Mr. Gruber for his testimony that Western has experienced successively declining revenues since the 1995 rate case.

Response:

See Mr. Smith's response to AG DR 37.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 30
Witness: Ives

Data Request:

Reference Mr. Gruber's testimony at page 20, lines 16-17. Provide a copy of the referenced Commission rules pertaining to distribution main extension, service line and meter for new customers.

Response:

See Ives testimony, Section V, starting on page 4. Attached are copies of KPSC Rules and Regulations, 807 KAR 5:022, as referenced by Mr. Ives:

Section (8) (2) (c)	Meters
Section (9) (16) (a)	Distribution Main
Section (9) (17) (a) 1.	Services Lines

(f) Plastic pipe being encased shall be inserted into casing pipe in a manner that will protect the plastic. The leading end of the plastic shall be closed before insertion.

(13) Casing. Each casing used on a transmission line or main under a railroad or highway shall comply with the following:

(a) Casing shall be designed to withstand superimposed loads.

(b) If there is a possibility of water entering the casing, ends shall be sealed.

(c) If ends of an unvented casing are sealed, and the sealing is strong enough to retain maximum allowable operating pressure of the pipe, the casing shall be designed to hold this pressure at a stress level of not more than seventy-two (72) percent of SMYS.

(d) If vents are installed on a casing, vents shall be protected from weather to prevent water from entering the casing.

(14) Underground clearance.

(a) Each transmission line shall be installed with at least twelve (12) inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, The transmission line shall be protected from damage that might result from proximity to other structures.

(b) Each main shall be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this subsection, each plastic transmission line or main shall be installed with sufficient clearance, or shall be insulated, from any source of heat to prevent heat from impairing serviceability of the pipe.

(d) Each pipe-type or bottle type holder shall be installed with minimum clearance from any other holder as prescribed in Section 4(19)(b) of this administrative regulation.

(15) Cover.

(a) Except as provided in paragraphs (c) and (d) of this subsection, each buried transmission line shall be installed with minimum cover as follows:

Normal Consolidated

Location Soil (inches) Rock (inches)

Class 1 locations 30 18

Class 2, 3 and 4 locations 36 24

Drainage ditches of public roads 36 24

and railroad crossings

(b) Except as provided in paragraphs (c) and (d) of this subsection, each buried main shall be installed with at least twenty-four (24) inches of cover.

(c) Where an underground structure prevents installation of a transmission line or main with minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) All pipe installed in a navigable river or stream shall have minimum cover of forty-eight (48) inches in soil or twenty-four (24) inches in consolidated rock. However, less than minimum cover is permitted in accordance with paragraph (c) of this subsection.

Section 8. Gas Measurement. (1) Scope. This section prescribes minimum requirements for measurement of gas, accuracy of measuring instruments (meters), meter testing facilities and periodic testing of meters.

(2) Method of measuring service.

(a) All gas sold by a utility and all gas consumed by a utility in the State of Kentucky shall be metered through approved type meters except in cases of emergency or when otherwise authorized by the commission. Each meter shall bear an identifying number. When gas is sold at high pressures or large volumes, the contract or rate schedule shall specify standards used to calculate gas volume. Prepayment meters shall not be used unless there is no other satisfactory method of collecting payment for services rendered.

(b) All gas delivered as compensation for leases, rights-of-way, or for other reasons, not charged at the utility's regular schedule of charges, shall be metered and a record kept of each transaction. All meters and regulators installed to measure gas and to regulate pressure of gas shall be under the control of the utility and subject to the rules of the utility and of the commission.

(c) The utility shall make no charge for furnishing and installing any meter or appurtenance necessary to measure gas furnished, except by mutual agreement as approved by the commission in special cases or except where duplicate or check meters are requested by the customer.

(d) Each gas utility shall adopt a standard method of meter and service line installation insofar as practicable. These methods shall be set out with a written description and with drawings as necessary for clear understanding of the requirements, all of which shall be filed with the commission. Copies of these standard methods shall be made available to prospective customers, contractors or others engaged in installing pipe for gas utilization. All meters shall be set in place by the utility.

(e) Each customer shall be metered separately except in cases of multioccupants under the same roof sharing a common entrance or an enclosure where it is unreasonable or uneconomical to measure each unit separately.

(f) The utility may render temporary service to a customer and may require the customer to bear all costs of installing and removing service in excess of any salvage realized. In this respect, temporary service shall be considered to be service that is not required or used for more than one (1) year.

(3) Accuracy requirements for meters. All tests to determine accuracy of registration of any gas meters shall be made by a qualified meter tester and with suitable facilities.

(a) Diaphragm displacement meters:

1. Before being installed for use by any customer, every diaphragm displacement gas meter, whether new, repaired or removed from service for any cause shall be in good working condition and shall be adjusted to be correct to within one-half (1/2) of one (1) percent, plus or minus when passing gas at approximately twenty (20) percent and 100 percent of the rated capacity of the meter as specified by the manufacturer based on five-tenths (0.5) inch water column differential. A pilot test or quartering test to determine that the meter will register at one-half (1/2) of one (1) percent of the rated capacity shall be made before placing meters in service.

2. Meters removed from service for periodic testing shall be tested for accuracy as soon as practical after removal. An "as found" test shall be made at a flow-rate of approximately twenty (20) percent and 100 percent of the rated capacity of the meter based on five-tenths (0.5) inch water column differential and results of these tests algebraically averaged to determine accuracy. If error is less than two (2) percent this shall be reported as the "as found" test. If error is more than two (2) percent, two (2) additional tests shall be made at twenty (20) percent and 100 percent, and the average of these three (3) tests shall be reported as the "as found" test. The three (3) test procedures shall apply to any customer request test, complaint test, or bill adjustment made on the basis of the meter.

3. Meters of good working condition that are removed from service for reasons other than periodic, customer or commission request tests shall be tested as soon as practicable after removal if elapsed time since the last test exceeds fifty (50) percent of the periodic test period for those meters.

(b) Other than diaphragm displacement meters.

1. All meters other than diaphragm displacement meters shall be tested at approved intervals by the utility meter tester using flow provers or other approved methods either in the shop or at the location of use at the utility's option and with the commission's approval of facilities and methods used. Accuracy of these meters shall be maintained as near 100 percent as possible. Test ranges and procedures shall be as prescribed in adopted standards or approved by the commission.

2. All meter installations shall be inspected for proper design and construction and all instruments, regulators and valves used in conjunction with installation shall be tested for desired operation and accuracy before being placed in service. This inspection shall be made by a qualified person. Test data as to conditions found, corrected if in error, and conditions as left shall be made available for inspection by commission staff. Subsequent test results shall be a portion of regular meter test reports submitted to the commission by the utility.

(4) Meter testing facilities and equipment.

(a) Meter shop.

1. Each utility, unless specifically excepted by the commission, shall maintain a meter shop to inspect, test and repair meters. The shop shall be open for inspection by commission staff at all reasonable times. Facilities and equipment, as well as methods of measurement and testing employed, shall be subject to approval of the commission.

2. The meter shop shall consist of a repair room or shop proper and a proving room. The proving room shall be designed so that meters and meter testing apparatus are protected from excessive changes in temperature and other disturbing factors. The proving room or the entire meter shop shall be air conditioned if necessary to achieve satisfactory temperature control.

3. The proving room shall be well lighted and preferably not on an outside wall of the building. Temperatures within the proving room shall not vary more than two (2) degrees Fahrenheit per hour nor more than five (5) degrees Fahrenheit over a twenty-four (24) hour period.

(b) Working standards.

1. Each utility, unless specifically excepted by the commission, shall own and make proper provision to operate at least one (1) approved belltype meter prover, preferably of ten (10) cubic feet capacity, but in no case of less than five (5) cubic feet capacity. The prover shall be equipped with suitable thermometers and other necessary accessories. This equipment shall be maintained in proper condition and adjustment so that it shall be capable of determining the accuracy of any service meter, practical to test by it, to within one-half (1/2) of one (1) percent plus or minus.

2. The prover shall be accurate to within three-tenths (0.3) of one (1) percent at each point used in testing meters.

3. The prover shall not be located near any radiator, heater, steam pipe, or hot or cold air duct. Direct sunlight shall not be allowed to fall on the prover or the meters under test.

4. During conditions of satisfactory operation air temperature in the prover shall be within one (1) degree Fahrenheit of the ambient temperature, and oil temperature in the prover shall not differ from the temperature of ambient air by more than one (1) degree Fahrenheit.

5. Meters to be tested shall be stored in such manner that temperature of the meters is substantially the same as temperature of the prover. To achieve this, meters shall be placed in the environment of the prover for a minimum of five (5) hours.

(c) All testing instruments and other equipment certified by the commission shall be accompanied at all times by a certificate showing the date when it was last tested and adjusted. The certificate must be signed by a proper authority designated by the commission. A tag referring to such certificate may be attached to the instruments when practicable. These certificates, when superseded, shall be kept on file by the utility.

(d) Sixty (60) days after the effective date of a commission order granting convenience and necessity for a new utility, that utility shall advise the commission in writing as to kind and amount of testing equipment available.

(5) Periodic tests.

(a) Periodic tests of all meters shall be made according to the following schedule based on rated capacities. Rated meter capacity is defined as the capacity of the meter at five-tenths (0.5) of one (1) inch water column differential for diaphragm meters and as specified by the manufacturer for all other meters.

1. Positive-displacement meters, with rated capacity up to and including 500 cubic feet per hour, shall be tested at least once every ten (10) years.

2. Positive-displacement meters, with rated capacity above 500 cubic feet per hour, up to and including 1,500 cubic feet per hour, shall be tested at least once every five (5) years.

3. Positive-displacement meters above 1,500 cubic feet per hour shall be tested at least once every year.

4. Orifice meters shall have their recording gauges tested at least once every six (6) months. Orifice size and condition shall be checked at the required meter test interval.

5. Auxiliary measurement devices such as pressure, temperature, volume, load demand and remote reading devices shall be tested at the required meter test interval.

(b) Whenever the number of meters of any type which register in error beyond the limits specified in these rules is deemed excessive, this type shall be tested with such additional frequency as the commission may direct.

(c) A utility desiring to adopt a scientific sample meter test plan for positive displacement meters in accordance with parameters established by the commission shall submit its application to the commission for approval. Upon approval, the sample testing plan may be followed in lieu of tests prescribed in subsections (3) and (5) of this section and 807 KAR 5:006, Section 13(1).

(6) Measuring production and shipment into and out of the state.

(a) The utility shall measure and record the quantity of all gas produced and purchased by it in Kentucky.

(b) The utility shall measure and record the quantity of all gas piped out of or brought into the state of Kentucky.

Section 9. Customer Meters, Service Regulators, and Service Lines. (1) Scope. This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

(2) Customer meters and regulators: location.

(a) Each meter and service regulator, whether inside or outside of a building, shall be installed in a readily accessible location and protected from corrosion and other damage.

(b) Meters shall be easily accessible for reading, testing and making necessary adjustments and repairs, and where indoor type meters are necessary they shall be installed in a clean, dry, safe, convenient place. Unless absolutely unavoidable, meters shall not be installed in any location where visits of the meter reader or tester will cause annoyance to the customer or severe inconvenience to the utility. Existing meters located in places not permitted by rule shall be relocated by the customer or owner to an approved position.

(c) Proper provision shall be made by the customer for installation of the utility's meter. At least six (6) inches clear space shall be available, if possible, on all sides of the meter and not less than thirty (30) inches in front of it. When installed within a building, a meter shall be located in a ventilated place and not less than three (3) feet from any source of ignition or any source of heat which might damage the meter.

(d) When a number of meters are placed in the same location, each meter shall be tagged or marked to indicate the customer served by it and such identification shall be preserved and maintained by the owner of the premises served.

(e) When the distance between the utility's main and nearest point of consumption is more than 150 feet, the meter shall be located as near to the utility's main as may be practicable. This provision shall apply when any part of the service line has been constructed by either the customer or utility.

(f) When a customer is served from a pipeline operating in excess of sixty (60) psig the meters, regulators and safety devices shall be located as near to the utility's pipeline as practicable.

(g) Each service regulator installed within a building shall be located as near as practical to point of service line entrance.

(h) Where feasible, the upstream regulator in a series shall be located outside the building unless it is located in a separate metering or regulating building.

(3) Customer meters and regulators: protection from damage.

(a) Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device shall be installed to protect the system.

(b) Service regulator vents and relief vents. Service regulator vents and relief vents shall terminate outdoors, and the outdoor terminal shall be:

1. Rain and insect resistant;

2. Located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

3. Protected from damage caused by submergence in areas where flooding may occur.

(c) Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated shall be able to support that traffic.

(4) Customer meter and regulators: installation.

(a) Each meter and each regulator shall be installed to minimize anticipated stresses upon the connecting piping and the meter.

(b) Use of all thread (close) nipples is prohibited.

(c) Connections made of lead or other easily damaged material shall not be used in installation of meters or regulators.

(d) Each regulator that might release gas in its operation shall be vented to the outside atmosphere and shall have a vent pipe sized no smaller than the manufacturer's vent connection built into the regulator.

(5) Customer meter installation: operation pressure.

(a) A meter shall not be used at pressure more than sixty-seven (67) percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, shall have been tested to a minimum of ten (10) psig.

(c) A rebuilt or repaired tinned steel case meter shall not be used at pressure more than fifty (50) percent of the pressure used to test the meter after rebuilding or repairing.

(6) Service lines: installation.

(a) Depth. Each buried service line shall be installed with at least twelve (12) inches of cover in private property and at least eighteen (18) inches of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line shall be able to withstand any anticipated external load.

(b) Support and backfill. Each service line shall be properly supported on undisturbed or well-compacted soil, and material used for backfill shall be free of materials that could damage the pipe or its coating.

(c) Grading for drainage. Where condensation in the gas might cause interruption in gas supply to the customer, the service line shall be graded to drain into the main or into drips at low points in the service line.

(d) Protection against piping strain and external loading. Each service line shall be installed to minimize anticipated piping strain and external loading.

(e) Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building shall:

1. If a metal service line, be protected against corrosion;

2. If a plastic service line, be protected from shearing action and backfill settlement; and

3. Be sealed at the foundation wall to prevent leakage into the building.

(f) Installation of service lines under buildings. Where an underground service line is installed under a building:

1. It shall be encased in a gastight conduit;

2. The conduit and the service line shall, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

3. The space between the conduit and service line shall be sealed to prevent gas leakage into the building. If the conduit is sealed at both ends, a vent line from the annular space shall extend to a point where gas would not be a hazard and extend above grade, terminating in a rain and insect resistant fitting.

(g) Joining of service lines. All underground steel service lines shall be joined by threaded and coupled joints, compression type fittings, or by qualified welding procedures and operators.

(h) When coated steel pipe is to be installed as a service line in a bore, care shall be exercised to prevent damage to the coating during installation. For all installations to be made by boring, driving or similar methods or in a rocky type soil, the following practices or their equivalents are recommended:

1. Coated pipe should not be used as the bore pipe or drive pipe and left in the ground as part of the service line. It is preferable to make such installations by first making an average bore, removing the pipe used for boring and then inserting the coated pipe.

2. Coated steel pipe preferably should not be inserted through a bore in exceptionally rocky soil when there is a likelihood of damage to the coating resulting from insertion.

3. Recommendations in subparagraphs 1 and 2 of this subsection do not apply where coated pipe is installed under conditions where the coating is not likely to be damaged, such as in sandy soil.

(7) Service line: valve requirements.

(a) Each service line shall have a service-line valve that meets applicable requirements of Sections 2 and 4 of this administrative regulation. A valve incorporated in a meter bar, that allows the meter to be bypassed, shall not be used as a service-line valve.

(b) A soft seal service-line valve shall not be used if its ability to control flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where blowing gas would be hazardous, shall be designed and constructed to minimize the possibility of removal of the valve core with other than specialized tools.

(8) Service lines: location of valves.

(a) Relation to regulator or meter. Each service-line valve shall be installed upstream of the regulator or, if there is not regulator, upstream of the meter.

(b) Outside valves. Each service line shall have a shutoff valve in a readily accessible location that, if feasible, is outside of the building.

(c) Underground valves. Each underground service-line valve shall be located in a covered, durable curb box or standpipe that allows ready operation of the valve. The curb box shall be supported independently of the service lines.

(9) Service lines general requirements for connections to main piping.

(a) Location. Each service-line connection to a main shall be located at the top of the main, or, if not practical, at the side of the main, unless a suitable protective device is installed to minimize possibility of dust and moisture being carried from the main into the service line.

(b) Compression-type connection to main. Each compression-type service line to main connection shall:

1. Be designed and installed to effectively sustain longitudinal pullout or thrust forces caused by contraction or expansion of piping, or by anticipated external or internal loading; and

2. If gaskets are used in connecting the service line to the main connection fitting, gaskets shall be compatible with the kind of gas in the system.

(10) Service lines: connection to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main shall be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting requirements of Section 6(2) of this administrative regulation.

(b) If a threaded tap is being inserted, the requirements of Section 4(6)(b) and (c) of this administrative regulation shall also be met.

(11) Service lines: steel. Each steel service line to be operated at less than 100 psig shall be constructed of pipe designed for a minimum of 100 psig.

(12) Service lines: cast iron and ductile iron. Cast or ductile iron pipe shall not be installed for service lines.

(13) Service lines: plastic.

(a) Each plastic service line outside a building shall be installed below ground level, except that it may terminate above ground and outside the building, if:

1. The above ground part of the plastic service line is protected against deterioration and external damage; and

2. The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building shall be protected against external damage.

(14) Service lines: copper. Each copper service line installed within a building shall be protected against external damage.

(15) New service lines not in use. Each service line not placed in service upon completion of installation shall comply with one (1) of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent flow of gas to the customer shall be provided with a locking device or other means designed to prevent opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent flow of gas shall be installed in the service line or in the meter assembly.

(c) The customer's piping shall be physically disconnected from the gas supply, and the open pipe ends sealed.

(16) Extension of services.

(a) Normal extension. An extension of 100 feet or less shall be made by a utility to an existing distribution main without charge for a prospective customer who shall apply for and contract to use service for one (1) year or more and provides guarantee for such service.

(b) Other extensions.

1. When an extension of the utility's main to serve an applicant or group of applicants amounts to more than 100 feet per customer, the utility shall, if not inconsistent with its filed tariff, require the total cost of the excessive footage over 100 feet per customer to be deposited with the utility by the applicant(s), based on average estimated cost per foot of the total extension.

2. Each customer receiving service under such extension will be reimbursed under the following plan: each year for a refund period of not less than ten (10) years, the utility shall refund to the customer(s) who paid for the excessive footage, the cost of 100 feet of extension in place for each additional customer connected during the year whose service line is directly connected to the extension installed, and not to extensions or laterals therefrom. Total amount refunded shall not exceed the amount paid to the utility. After the end of the refund period, no refund shall be required.

(c) An applicant desiring an extension to a proposed real estate subdivision may be required to pay all costs of the extension. Each year for a refund period of not less than ten (10) years, the utility shall refund to the applicant who paid for the extension a sum equivalent to the cost of 100 feet of extension installed for each additional customer connected during the year. Total amount refunded shall not exceed the amount paid to the utility. After the end of the refund period from the completion of the extension, no refund shall be required.

(d) Nothing contained herein shall be construed to prohibit the utility from making extensions under different arrangements provided such arrangements have been approved by the commission.

(e) Nothing contained herein shall be construed to prohibit a utility from making, at its expense, greater extensions than herein prescribed, provided the same free extensions are made to other customers under similar conditions.

(f) Upon complaint to and investigation by the commission, a utility may be required to construct extensions greater than 100 feet upon a finding by the commission that such extension is reasonable.

(17) Service connections.

(a) Ownership of service lines.

1. Utility's responsibility. In urban areas with well defined streets, the utility shall furnish and install at its own expense, for the purpose of connecting its distribution system to customer premises, that portion of service pipe from its main to the property line or to and including the curb stop and curb box if used. The curb stop may be installed at a convenient place between property line and curb. If meters are located outdoors, the curb box and curb stop may be omitted if meter installation is provided with a stopcock and connection to the distribution main is made with a service tee that incorporates a positive shutoff device that can be operated with ordinary, readily available tools and the service tee is not located under pavement.

2. Customer's responsibility. The customer, or the company at its option and with commission approval, shall furnish and lay necessary pipe to make the connection from curb stop to place of consumption and shall keep the service line in good repair and in accordance with reasonable requirements of the utility's rules and the commission's administrative regulations.

3. Inspection. In the installation of a service line, the customer shall not install any tees or branch connections and shall leave the trench open and pipe uncovered until it is examined by an inspector of the utility and shown to be free from any irregularity or defect. The utility shall test all piping downstream from the meter for gas leaks, each time gas is turned on by the utility, by observing that no gas passes through the meter when all appliances are turned off. The utility shall refuse to serve until all gas leaks so disclosed have been properly repaired.

4. Location of service. The customer's service line shall extend to that point on the curb line easiest of access to the utility from its distribution system. When a reasonable doubt exists as to the proper location of the service line, the utility shall be consulted and its approval of the location secured.

(b) All services shall be equipped with a stopcock near the meter. If the service is not equipped with an outside shutoff, the inside shutoff shall be of a type which can be sealed in the off position.

Section 10. Requirements for Corrosion Control. (1) Scope. This subsection prescribes minimum requirements for protection of metallic pipelines from external, internal, and atmospheric corrosion.

(2) Applicability to converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this administrative regulation in accordance with Section 1(7) of this administrative regulation shall meet the requirements of this subsection specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within one (1) year after the pipeline is readied for service. However, the requirements of this section specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(3) General. Each operator shall establish procedures to implement the requirements of this section. These procedures, including those for design, installation, operation and maintenance of cathodic protection systems, shall be carried out by, or under the direction of a person qualified by experience and training in pipeline corrosion control methods.

(4) External corrosion control: buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this subsection, each buried or submerged pipeline installed after July 31, 1971, shall be protected against external corrosion, including the following:

1. It shall have an external protective coating meeting the requirements of subsection (7) of this section.

2. It shall have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subsection, installed and placed in operation within one (1) year after completion of construction.

(b) An operator need not comply with paragraph (a) of this subsection if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six (6) months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed twenty (20) feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests indicate that a corrosive condition exists, the pipeline shall be cathodically protected in accordance with paragraph (a)2 of this subsection.

(c) An operator need not comply with paragraph (a) of this subsection, if the operator can demonstrate by tests, investigation, or experience that:

1. For a copper pipeline, a corrosive environment does not exist; or

2. For a temporary pipeline with an operating period of service not to exceed five (5) years beyond installation, corrosion during the five (5) year period of service of the pipeline will not be detrimental to public safety.

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Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 31
Witness: Smith

Data Request:

Reference Mr. Gruber's testimony at page 7, lines 4-5.

a. Does Mr. Gruber believe the Company's proposed Weather Normalization Adjustment provides benefits to customers? If so, please both describe the nature of the benefits and please quantify the typical or range of benefit to be received by residential customers.

b. In Mr. Gruber's opinion, must the WNA be offered on a mandatory, rather than optional basis? If so, please explain with specificity why a voluntary WNA would not be reasonable and why a mandatory WNA is reasonable.

Response:

Mr. Smith will address the questions posed above as he is Western's expert witness on the benefits of WNA, WNA rate design, and the administration of WNA programs. Mr. Gruber only addresses WNA in his testimony in reference to the general problem of winter weather volatility on the Company's financial performance.

a. Yes.

As indicated in my testimony in Volume 2 of 10 of the Application, Tab 11, at page 35, lines 21-22, "The proposed WNA would stabilize customer bills, making them more predictable during the heating season."

To "quantify the benefit or range of benefit" of more stable and predictable customer bills, we investigated the range of variance from normal over recent years. The reference utilized for annual weather variations from normal can be found on sheets 2 through 5 on the attachment Schedules to PSC DR No. 1 - Item 59(b). The maximum variance from normal was 15.6 %. Attached Schedule AG DR No.1 - Item 31 calculates that the WNA proposal would eliminate a $11.02 (+/-) variable in the average customers bill through winter months, if weather during the period varied from normal by 15% (+/-).

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b. I have not analyzed the reasonableness or unreasonableness of a voluntary WNA program. I offer the opinions below in order to be responsive. However, it is difficult for me to fully examine the various implications of a voluntary WNA given workload associated with the extensive data request requirements from the AG and the KPSC.

I am not aware of any voluntary WNA programs in existence. The purpose of a WNA is to stabilize revenues for the Company and stabilize billings for customers, making winter earnings and billings more predictable. It would appear that a voluntary WNA program would lessen the stabilization effect and predictability for both the Company and customers. A voluntary program would certainly be more complex to administer and would negate the administrative ease and low incremental cost of implementing the same WNA administrative processes now in use at Atmos for United Cities Gas. Atmos has no experience with a voluntary WNA. A voluntary program would make WNA rate design and normalization calculations very difficult because of the potentially changing subset of customers in the "participating" in the program.

The benefits of Western's proposed WNA are tied to its universal nature; that is, the stabilization of Company earnings and customer billings, and the greater predictability of earnings and billings. Certainly, the administrative benefits of the Western's specific WNA proposal, as discussed in my testimony, are premised upon implementing a program with which Atmos is already familiar. WNAs have been proposed and adopted in various jurisdictions because of the mutual benefit derived for both the Company and customers. A voluntary program would likely alter that mutual benefit.

Western already has another voluntary program that the customer can use to stabilize their bills. That program is budget billing. Budget billing which includes the GCA revenues as well as the Company's margin. However, budget billing requires an annual true-up for the customer and it does not stabilize earnings for the Company.

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Line No.	Item (a)	Calculated Value (b)	Source/Calculation Method (c)
1	Normal Lagged Degree-Days, November through April =	3,974.5	Volume 2 of 10, Tab 11 of the Company's Application,
2			Exhibit GLS-4, Sum of Column (e) lines 3 through 8.
3			
4	Variance from normal weather of 15%, in Degree-days =	596.2	Column b, line 1 times 15%
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 152, Sheet 1 of 4, column h, line 17
9			
10	Average Base Load, November-April, Mcf/customer=	9.27	Column b, line 8 times 6 months
11			
12	Weighted Average Rate ("R") for residential class,		
13	at Proposed Rates =	1.2000	AG DR No. 1, Item 153, Sheet 1 of 1, column h, line 8
14			
15	Calculated WNA, at Proposed Rates, at 15% warmer	0.1797	Formula stated in proposed tariff at First-revised Sheet
16	than Normal Weather (ADD = 3,577)		No. 26, applying the factors above on this Schedule.
17			
18	Calculated WNA, at Proposed Rates, at 15% colder	(0.1383)	Formula stated in proposed tariff at First-revised Sheet
19	than Normal Weather (ADD = 4,372)		No. 26, applying the factors above on this Schedule.
20			
21	Estimated Average Normal Residential Usage,	70.5	Column b, line 1 times Column b, line 6 plus
22	November through April		Column b, line 10
23			
24	Mcf variance at 15% variance in normal weather =	9.2	Column b, line 1 times Column b, line 6 times 15%
25			
26	Calculated Total Affect of WNA, at Proposed	$11.02 *	Column b, line 15 times 64.4 Mcf (Column b, line 21
27	Rates, at 15% warmer than Normal Weather		minus Column b, line 24)
28			
29	Calculated Total Affect of WNA, at Proposed	($11.02) *	Column b, line 18 times 76.6 Mcf (Column b, line 21
30	Rates, at 15% colder than Normal Weather		plus Column b, line 24)
31			
32	* - This is the estimated affect of the WNA component on the average residential customers billings through the winter season months of November		
33	through April. The impact of Commodity gas cost differences, due to increased or decreased usage are not included in this calculation.		

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 32
Witness: Gruber

Data Request:

Reference Mr. Gruber's testimony at page 20, lines 18-19. In Kentucky, is the Company required to provide 100 feet of main, a service line and a meter, at no cost to the customer, for each and every customer who requests gas service? If yes, please explain what it is that requires the Company to provide universal gas service to all requestors in the Company's Kentucky service area.

Response:

Yes. Mr. Ives' testimony on pages 4-6 discusses the various and applicable Commission rules and provisions of the Company's tariff, including 807 KAR 005:022, 16 (a), which reads as follows:

> (16) Extension of services. (a) Normal extension. An extension of 100 feet or less shall be made by a utility to an existing distribution main without charge for a prospective customer who shall apply for and contract to use service for one (1) year or more and provides guarantee for such service.

Therefore, under the Commission rules, Western is currently obligated to serve customers located within 100 feet of an existing distribution main. Western is also currently obligated to serve customers located more than 100 feet from an existing distribution main if the customer is willing to pay for the portion of any extension in excess of 100 feet. Mr. Ives also references the important issue of "economic feasibility" as covered in Section 28 of the tariff. In practice, Western currently views a customer's request for heat load as essential for satisfying the condition of "economic feasibility" and, therefore, triggering its obligation to serve regardless of the inadequacy of current rate design. This economic feasibility test in the tariff, however, does not supercede the Commission's mandate to extend service in 807 KAR 5:022 (16) (a).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 33 a-d
Witness: Gruber

Data Request:

Reference Mr. Gruber's testimony at page 22, lines 11-12.

a. Please clarify whether Mr. Gruber's use of the term energy refers to the energy component of service or to the delivered price of energy. If other, please explain.

b. Please explain how the Commission's approval of the Company's residential proposals in this case will ensure that energy prices will be kept lower than they otherwise would be.

c. What would residential energy prices otherwise be, in Mr. Gruber's opinion?

d. How much lower will residential energy prices be, in Mr. Gruber's opinion, if the Company's proposals are approved by the Commission?

Response:

a. The statement can apply to both, although in the context of the rate case this statement applies to the non-gas cost of service, which is a component of the delivered price of energy.

b. If Western is not allowed to implement residential and other prices which can sustain the Company financially, it will not be able to afford to incur operating costs and make the investments necessary to maintain its viability as an energy provider in the marketplace. Absent Western's presence in the market, other energy providers would be under less pressure to operate efficiently, ultimately resulting in higher end user prices.

c. Higher.

d. Obviously, I cannot give an exact answer to the question. However, Western has the lowest gas prices of the major gas companies in the Commonwealth today. Even with the proposed increase our price will still be the lowest of any pure gas utility. Approval of this necessary and reasonable request will send a strong signal to the market that efficient energy providers like Western will be rewarded for good behavior which keeps costs low, and encourage the kind of innovation and efficiency we have implemented. I am confident that the Commission's approval of our proposals will encourage other service providers to seek greater efficiency because I believe rewards and incentives are a strong motivator.

Western Kentucky Gas Company
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Attorney General Initial Data Request Dated August 19, 1999
DR Item 33, e
Witness: Gary Smith

Data Request:

33. Refer to Mr. Gruber's testimony on page 22, lines 11-12.

    e. Will the proposed Premises Charge help or hinder Western in competing with electricity in the new homes' space heating market? Explain.

Response:

The proposed Premises Charge, as well as other rate design features of Western's case, will help Western in competing with electricity in the residential market. In fact, these rate design elements are essential to maintain Western's competitive viability.

Please reference my testimony, Volume 2 of 10, Tab 11, of the Company's application, at page 18, line 2 through page 20, line 8, which addresses the problems faced by Western in the residential market under current rate structures.

It is Western's desire that reasonable system expansion continues to occur to meet the service desires of nearby homes. Under current rate structures and main extension guidelines, the extension of service to new residential customers is unprofitable. The Premises Charge is designed to sustain Western financially as we add new residential service connection, fundamental to maintaining our competitive viability in this market.

Lastly, please refer to Mr. Gruber's response to AG Data Request 33(b).

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Attorney General Initial Data Request Dated August 19, 1999
DR Item 34
Witness: Hack

Data Request:

Reference Mr. Hack's testimony at page 2, lines 15-16. Please provide gas delivery interruption experience on the Company's system, for gas otherwise reaching the Company's city gates, for the last ten years:

a. Dates of interruptions;

b. Volumes interrupted;

c. Number of customers interrupted and class in which such interrupted customers are housed; and

d. Reason for interruptions.

Response:

a. 1. February 15, 1991

2. February 18, 1993 (5:30 a.m. til 11:30 a.m.)

3. February 6, 1995 (7:30 a.m. til 11:30 p.m.)

b. 1. Notified to hold current consumption level

2. Partial day - quantity unknown

3. Partial day - quantity unknown

c. 1. 2 customers - industrial

2. 4 customers - 3 industrial, 1 commercial

3. 5 customer - 4 industrial, 1 commercial

d. 1. system low pressure

2. system low pressure

3. system low pressure

Note: The above does not include curtailment of interruptible customers to stay within pipeline contract compliance.

Western Kentucky Gas Company
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Attorney General Initial Data Request Dated August 19, 1999
DR Item 35
Witness: Gary Smith

Data Request:

35. Refer to Mr. Smith's testimony at page 3, lines 21-25. Please provide copy of source information and workpapers detailing the calculation of the referenced 1.5 percent and 0.5 percent growth rates.

Response:

See attached Schedule AG DR NO. 1 - Item 35, Sheets 1-2, for the workpapers detailing the calculations of the population changes in counties served by Western Kentucky Gas Company. The source of the information was a 1998 report from the Kentucky State Data Center web-site of the University of Louisville's Kentucky Population Research group. Copies of the source data are also included in the attached Schedule AG DR NO. 1 - Item 35, at Sheets 3-6.

The 1.5 percent reference is found in column d, line 28. The growth rate from 1990-1995 (column e, line 28), annualized is slightly less than 0.4%.

Western Kentucky Gas Company
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AG Data Request Dated August 19, 1999
DR Item 35
Witness: Gary Smith

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1				Change	Growth Projections		
2		1980	1990	1980-1990	1995	2000	2010
3							
4	Owensboro District:						
5							
6	Breckinridge	16,861	16,312	-549	16,250	16,122	15,789
7	Daviess	85,949	87,189	1,240	88,272	88,767	89,269
8	Hancock	7,742	7,864	122	8,046	8,199	8,386
9	McLean	10,090	9,628	-462	9,526	9,404	9,108
10	Ohio	21,765	21,105	-660	21,630	21,103	21,076
11							
12		142,407	142,098	-309	143,724	143,595	143,628
13							
14	Danville District:						
15							
16	Anderson	12,567	14,571	2,004	15,986	17,319	19,455
17	Boyle	25,066	25,641	575	25,729	25,703	25,508
18	Garrard	10,853	11,579	726	12,150	12,677	13,443
19	Green	11,043	10,371	-672	10,210	10,003	9,623
20	Lincoln	19,053	20,045	992	20,983	21,814	22,953
21	Marion	17,910	16,499	-1,411	16,286	16,045	15,700
22	Mercer	19,011	19,148	137	19,388	19,509	19,547
23	Shelby	23,328	24,824	1,496	26,169	27,344	28,990
24	Taylor	21,178	21,146	-32	21,359	21,421	21,419
25	Washington	10,764	10,441	-323	10,617	10,480	10,478
26							
27		170,773	174,265	3,492	178,877	182,315	187,116
28							
29	Bowling Green District:						
30							
31	Barren	34,009	34,001	-8	34,063	33,945	33,398
32	Hart	15,402	14,890	-512	14,992	15,057	15,062
33	Logan	24,138	24,416	278	24,789	25,078	25,515
34	Simpson	14,673	15,145	472	15,619	16,015	16,576
35	Todd	11,874	10,940	-934	10,923	10,869	10,802
36	Warren	71,828	77,720	5,892	80,783	84,491	90,262
37							
38		171,924	177,112	5,188	181,169	185,455	191,615

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DR Item 35
Witness: Gary Smith

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1				Change	Growth Projections		
2		1980	1990	1980-1990	1995	2000	2010
3							
4	Paducah District:						
5							
6	Graves	34,049	33,550	-499	33,640	33,675	33,716
7	Livingston	9,219	9,062	-157	9,055	8,981	8,763
8	McCracken	61,310	62,879	1,569	63,863	64,439	64,653
9	Marshall	25,637	27,205	1,568	28,147	28,882	29,593
10							
11		130,215	132,696	2,481	134,705	135,977	136,725
12							
13	Madisonville District:						
14							
15	Caldwell	13,473	13,232	-241	13,256	13,227	13,105
16	Christian	66,878	68,941	2,063	71,289	73,425	77,534
17	Crittenden	9,207	9,196	-11	9,342	9,449	9,566
18	Hopkins	46,174	46,126	-48	46,311	46,272	45,807
19	Lyon	6,490	6,624	134	6,726	6,796	6,774
20	Muhlenberg	32,238	31,318	-920	31,285	31,125	30,627
21	Trigg	9,384	10,361	977	11,102	11,764	12,398
22	Webster	14,832	13,955	-877	13,734	13,520	13,195
23							
24		198,676	199,753	1,077	203,045	205,578	209,006
25							
26	TOTAL WKG	813,995	825,924	11,929	841,520	852,920	868,090
27							
28			Growth Rate	1.47%	1.89%	1.35%	1.78%
29			Period	80-90	90-95	95-00	00-10

Table 2. To[illegible]opulation Projections, High Growth and Moderate Growth S[illegible]s, Kentucky, Area Development Districts, Counties: 1995-20[illegible]

	Census 1980	Census 1990	1995 Moderate Growth	1995 High Growth	2000 Moderate Growth	2000 High Growth	2010 Moderate Growth	2010 High Growth	2020 Moderate Growth	2020 High Growth
Kentucky	3,660,777	3,686,891	3,765,130	3,867,477	3,824,639	4,040,675	3,903,813	4,317,191	3,927,352	4,530,750
Barren River ADD	217,041	222,766	227,921	236,347	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Big Sandy ADD	161,759	165,020	163,708	169,056	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bluegrass ADD	547,280	590,336	616,106	634,208	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Buffalo Trace ADD	54,636	51,877	51,903	54,206	51,742	56,694	51,294	60,372	50,728	63,425
Cumberland Valley ADD	227,557	223,024	226,049	233,195	228,235	243,514	231,245	258,183	230,755	268,288
Fivco ADD	140,734	132,685	132,047	136,236	130,759	142,016	127,421	148,090	122,906	150,159
Gateway ADD	66,240	65,346	67,144	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Green River ADD	199,048	199,342	201,112	205,028	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kentuckiana ADD	804,395	796,491	808,436	828,652	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kentucky River ADD	134,437	123,495	123,233	127,163	122,483	133,038	121,106	140,765	118,246	144,820
Lake Cumberland ADD	171,049	174,283	177,937	185,198	180,670	195,275	183,260	208,222	182,509	217,805
Lincoln Trail ADD	217,666	219,101	225,476	230,855	230,868	243,251	239,529	261,465	244,153	274,849
Northern Kentucky ADD	313,550	334,979	351,409	360,331	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pennyrile ADD	204,937	205,800	209,289	207,786	211,908	215,767	[illegible]	[illegible]	217,561	[illegible]
Purchase ADD	180,348	181,346	183,360	187,867	184,508	[illegible]	[illegible]	[illegible]	[illegible]	205,704
Adair	15,233	15,360	15,557	16,235	15,690	17,170	15,777	18,425	15,667	19,515
Allen	14,128	14,628	15,128	15,531	15,580	16,233	16,359	17,387	17,067	18,487
Anderson	12,567	14,571	15,968	17,143	17,319	19,375	19,455	22,917	20,991	26,394
Ballard	8,798	7,902	7,713	8,125	7,523	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Barren	34,009	34,001	34,063	35,358	33,945	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bath	10,025	9,692	9,669	10,164	9,623	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bell	34,330	31,506	31,207	30,757	30,751	30,720	29,853	30,467	28,798	29,762
Boone	45,842	57,589	64,911	69,548	72,057	79,172	84,009	94,672	92,854	109,373
Bourbon	19,405	19,236	19,639	19,394	19,976	20,303	20,500	21,612	20,900	22,676
Boyd	55,513	51,150	50,020	50,699	48,618	51,295	[illegible]	[illegible]	[illegible]	[illegible]
Boyle	25,066	25,641	25,729	26,614	25,708	27,202	[illegible]	[illegible]	[illegible]	[illegible]
Bracken	7,738	7,766	8,002	8,254	8,202	8,750	[illegible]	[illegible]	[illegible]	[illegible]
Breathitt	17,004	15,703	15,776	15,438	15,756	15,654	15,638	15,926	15,333	15,911
Breckinridge	16,861	16,312	16,250	16,700	16,122	17,451	15,789	18,309	15,245	18,774
Bullitt	43,346	47,567	51,370	56,044	54,736	61,891	59,579	70,625	62,371	77,825
Butler	11,064	11,245	11,468	11,649	11,617	12,088	11,795	12,697	11,776	[illegible]
Caldwell	13,473	13,232	13,256	13,161	13,227	13,242	13,106	13,289	12,957	[illegible]
Calloway	30,031	30,735	31,236	32,485	31,558	33,789	31,638	35,358	31,565	36,664

Table 2. Total Population Projections, High Growth and Moderate Growth Series, Kentucky, Area Development Districts, Counties: 1995-2020.

	Census 1980	Census 1990	1995 Moderate Growth	1995 High Growth	2000 Moderate Growth	2000 High Growth	2010 Moderate Growth	2010 High Growth	2020 Moderate Growth	2020 High Growth
Campbell	83,317	83,866	85,270	87,190	85,978	91,397	87,088	98,380	87,641	105,238
Carlisle	5,487	5,238	5,179	5,332	5,125	5,558	5,000	5,888	4,846	6,272
Carroll	9,270	9,292	9,428	9,685	9,502	10,372	9,656	11,419	9,707	12,198
Carter	[illegible]	24,340	24,320	26,018	24,174	27,706	23,751	29,750	23,030	31,056
Casey	[illegible]	14,211	14,102	14,569	13,960	15,257	13,659	16,199	13,278	16,795
Christian	[illegible]	[illegible]	71,289	67,619	73,425	71,381	77,534	77,999	81,742	84,621
Clark	28,322	29,496	30,129	30,732	30,558	31,798	30,967	33,279	30,774	34,264
Clay	22,752	21,746	21,801	22,916	21,851	23,703	22,087	24,712	22,051	24,770
Clinton	9,321	9,135	9,153	9,307	9,134	9,531	9,059	9,740	8,869	9,797
Crittenden	9,207	9,196	9,342	9,476	9,449	9,802	9,566	10,380	9,603	10,967
Cumberland	7,289	6,784	6,683	6,827	6,681	6,842	6,896	6,817	6,256	6,742
Daviess	85,949	87,189	88,272	90,794	88,767	93,717	89,269	97,889	88,958	100,614
Edmonson	9,962	10,357	10,969	10,618	11,521	11,251	12,268	12,080	12,831	12,827
Elliott	6,908	6,455	6,797	6,678	7,155	7,281	7,803	8,451	8,542	9,661
Estill	14,495	14,614	14,768	15,616	14,863	16,297	14,927	16,954	14,749	17,163
Fayette	204,165	225,366	235,701	241,728	244,713	260,861	257,621	290,000	261,936	317,032
Fleming	12,323	12,292	12,375	13,036	12,396	13,849	12,874	15,059	12,290	16,110
Floyd	48,764	43,586	43,163	44,309	42,570	45,901	41,741	48,066	40,743	49,160
Franklin	41,830	44,143	44,878	45,975	45,672	47,494	46,554	49,108	46,466	49,901
Fulton	8,971	8,271	8,138	7,383	7,988	7,351	7,662	7,247	7,373	7,098
Gallatin	4,842	5,393	5,863	6,175	6,330	6,788	7,169	7,811	7,967	8,869
Garrard	10,853	11,579	12,150	12,879	12,677	13,775	13,443	14,998	13,927	16,100
Grant	13,308	15,737	17,524	18,517	19,306	20,911	22,318	24,826	24,596	28,716
Graves	34,049	33,550	33,640	34,986	33,675	35,744	33,716	36,677	33,716	37,478
Grayson	20,854	21,050	21,389	22,901	21,644	24,561	21,901	26,738	21,710	28,311
Green	11,043	10,371	10,210	10,370	10,006	10,401	9,623	10,304	9,266	10,176
Greenup	39,132	36,742	36,740	37,532	36,542	39,316	35,693	40,764	34,362	40,689
Hancock	7,742	7,864	8,046	8,235	8,199	8,760	8,386	9,465	8,374	9,879
Hardin	88,917	89,240	92,580	91,406	95,442	96,046	99,934	102,896	102,373	107,807
Harlan	41,889	36,574	36,092	36,277	35,491	36,312	34,525	36,256	33,449	35,557
Harrison	15,166	16,248	16,943	17,023	17,596	17,908	18,623	19,227	19,246	20,300
Hart	15,402	14,890	14,992	16,225	15,057	17,037	15,062	17,975	15,001	18,487
Henderson	40,849	43,044	44,078	44,564	44,851	46,110	45,882	47,960	45,991	48,625
Henry	12,740	12,823	13,143	14,061	13,392	14,944	13,717	16,315	13,797	17,520
Hickman	6,065	5,566	5,444	5,367	5,318	5,309	5,103	5,229	4,981	5,166
Hopkins	46,174	46,126	46,311	46,542	46,272	47,600	45,807	49,109	44,857	50,252

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Table 2. Tot[illegible]pulation Projections, High Growth and Moderate Growth Se[illegible] Kentucky, Area Development Districts, Counties: 1995-20[illegible]

	Census		1995		2000		2010		2020	
	1980	1990	Moderate Growth	High Growth	Moderate Growth	High Growth	Moderate Growth	High Growth	Moderate Growth	High Growth
Jackson	11,996	11,955	12,152	12,725	12,316	13,689	12,560	15,069	12,682	16,214
Jefferson	685,004	665,123	665,478	675,551	660,460	676,555	647,851	707,981	632,979	732,026
Jessamine	26,146	30,508	33,049	34,363	35,277	38,075	38,756	43,761	40,828	48,984
Johnson	24,432	23,248	23,224	24,163	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kenton	137,058	142,031	145,946	148,830	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Knott	17,940	17,906	18,212	18,589	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Knox	30,239	29,676	29,892	31,607	30,000	33,802	30,164	36,905	30,074	39,384
Larue	11,922	11,679	11,681	12,499	11,650	12,859	11,561	13,335	11,424	13,661
Laurel	38,982	43,438	45,939	48,092	48,229	51,709	51,588	56,791	53,114	60,670
Lawrence	14,121	13,998	14,170	15,309	14,270	16,418	[illegible]	[illegible]	[illegible]	[illegible]
Lee	7,754	7,422	7,396	7,807	7,386	8,075	[illegible]	[illegible]	[illegible]	[illegible]
Leslie	14,882	13,642	13,692	14,000	13,659	14,903	13,637	16,083	13,472	16,795
Letcher	30,687	27,000	26,638	27,296	26,203	28,726	25,445	30,344	24,478	30,929
Lewis	14,545	13,029	12,849	13,333	12,642	13,722	12,240	14,325	11,791	14,730
Lincoln	19,053	20,045	20,983	21,502	21,814	22,677	22,953	24,375	23,672	25,854
Livingston	9,219	9,062	9,055	9,374	8,981	9,888	8,763	10,369	8,422	10,649
Logan	24,138	24,416	24,789	25,724	25,078	27,066	25,516	28,949	25,621	30,387
Lyon	6,490	6,624	6,726	7,696	6,796	8,206	6,774	8,810	6,508	9,520
McCracken	61,310	62,879	63,863	65,106	64,439	67,176	64,653	69,578	64,121	71,007
McCreary	15,634	15,603	16,003	16,410	16,336	17,214	16,819	18,522	16,969	19,551
McLean	10,090	9,628	9,526	9,715	9,404	9,905	9,108	10,076	8,741	10,073
Madison	53,352	57,508	61,292	63,002	64,837	67,802	[illegible]	[illegible]	73,773	79,965
Magoffin	13,515	13,077	13,147	13,749	13,197	14,256	13,270	[illegible]	13,180	14,999
Marion	17,910	16,499	16,286	16,674	16,045	17,053	15,700	[illegible]	15,318	17,814
Marshall	25,637	27,205	28,147	29,105	28,882	30,631	29,593	32,365	29,694	33,612
Martin	13,925	12,526	12,576	13,033	12,548	13,547	12,538	14,224	12,384	14,443
Mason	17,765	16,666	16,550	17,351	16,379	17,991	16,045	18,833	15,809	19,464
Meade	22,854	24,170	25,624	26,734	27,026	27,910	29,660	[illegible]	31,826	30,860
Menifee	5,117	5,092	5,125	5,303	5,165	5,478	6,147	[illegible]	5,068	5,961
Mercer	19,011	19,148	19,388	20,001	19,509	20,951	19,547	22,117	19,378	22,925
Metcalfe	9,484	8,963	8,888	9,291	8,809	9,590	8,687	9,860	8,529	9,945
Monroe	12,353	11,401	11,222	11,692	11,015	11,823	10,661	11,939	10,246	11,876
Montgomery	20,046	19,561	19,665	20,443	19,719	21,057	19,630	21,619	19,335	21,764
Morgan	12,103	11,648	11,693	13,486	11,697	14,220	11,691	15,294	11,599	16,106
Muhlenberg	32,238	31,318	31,265	31,174	31,126	31,653	30,627	31,897	29,825	31,402
Nelson	27,584	29,710	31,176	33,325	32,461	36,525	34,568	41,565	35,976	46,164

Table 2. Total Population Projections, High Growth and Moderate Growth Series, Kentucky, Area Development Districts, Counties: 1995-2020.

	Census 1980	Census 1990	1995 Moderate Growth	1995 High Growth	2000 Moderate Growth	2000 High Growth	2010 Moderate Growth	2010 High Growth	2020 Moderate Growth	2020 High Growth
Nicholas	7,157	6,725	6,636	6,957	6,551	7,220	6,361	7,548	6,146	7,747
Ohio	21,765	21,105	21,103	21,630	21,076	22,285	21,003	23,228	20,763	23,718
Oldham	27,795	33,263	38,625	41,093	43,985	47,305	53,216	57,463	60,549	66,576
Owen	8,924	9,035	9,361	9,806	9,671	10,906	10,169	12,568	10,490	14,127
Owsley	5,709	5,036	4,874	5,449	4,722	5,624	4,482	5,842	4,258	5,958
Pendleton	10,989	12,036	13,108	13,581	14,172	15,422	16,108	18,405	18,000	21,482
Perry	33,763	30,283	30,123	31,359	29,796	32,414	29,170	33,623	28,233	33,998
Pike	81,123	72,583	71,598	73,711	70,252	74,783	67,365	74,262	63,660	71,125
Powell	11,101	11,686	12,114	12,373	12,480	13,423	13,117	15,032	13,499	16,240
Pulaski	45,803	49,489	51,648	54,352	53,459	58,552	55,373	63,545	55,641	67,009
Robertson	2,265	2,124	2,127	2,231	2,123	2,382	2,139	2,620	2,167	2,854
Rockcastle	13,973	14,803	15,332	15,495	15,790	16,321	16,410	17,522	16,637	18,480
Rowan	19,049	20,353	20,992	21,755	21,540	23,190	22,096	25,298	22,364	27,188
Russell	13,708	14,716	15,439	16,022	16,074	17,066	16,889	18,520	17,168	19,926
Scott	21,813	23,867	25,208	27,274	26,460	29,558	28,405	33,016	29,662	35,856
Shelby	23,328	24,824	26,169	27,476	27,344	29,438	28,990	32,313	29,848	34,700
Simpson	14,673	15,145	15,619	16,097	16,015	17,243	16,576	18,914	16,976	20,287
Spencer	5,929	6,801	7,495	7,803	8,192	8,583	9,394	9,849	10,325	11,065
Taylor	21,178	21,146	21,359	22,677	21,421	23,851	21,419	25,462	21,283	26,668
Todd	11,874	10,940	10,923	11,340	10,869	11,708	10,802	12,236	10,803	12,617
Trigg	9,384	10,361	11,102	11,405	11,764	12,306	12,398	13,249	12,544	13,949
Trimble	6,253	6,090	6,186	6,823	6,217	7,317	6,311	8,060	6,384	8,678
Union	17,821	16,557	16,353	16,512	16,190	16,766	16,018	17,118	15,674	17,063
Warren	71,828	77,720	80,783	84,163	84,491	89,372	90,262	97,160	94,286	103,022
Washington	10,764	10,441	10,480	10,617	10,478	10,846	10,416	11,221	10,281	11,457
Wayne	17,022	17,468	17,783	18,429	18,019	19,391	18,246	20,690	18,112	21,626
Webster	14,832	13,955	13,734	13,577	13,520	13,774	13,195	14,035	12,874	14,075
Whitley	33,396	33,326	33,633	35,326	33,807	37,257	34,058	40,460	33,950	43,452
Wolfe	6,698	6,508	6,522	7,225	6,525	7,832	6,534	8,775	6,375	9,536
Woodford	17,778	19,955	21,531	21,632	23,016	23,413	25,243	25,992	26,493	28,045

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 36, a - c
Witness: Gary Smith

Data Request:

36. Refer to Mr. Smith's testimony at pages 3-4, lines 28-30, and 1-2, respectively.

a. Please provide new customer additions attributable to new residential developments for each year 1990 through estimated 2000.

b. Please provide new customer additions due to "number of nearby conversion candidates" for each year 1990 through estimated 2000.

c. Please provide gas service saturation data indicating the percent of new residential construction that utilizes gas service.

Response:

Applicable to the response to sub-parts (a) and (b) of this data request item, please refer to the Company's response to PSC DR 1, dated July 16, 1999 - Item 58(d), and PSC DR 2, dated August 19, 1999 - Item 45(a). Western's marketing reports represent the only available source for the segmentation of residential customer additions requested in this Attorney General request. As stated in the Company's responses to PSC data requests referenced above, these historical marketing reports are of questionable accuracy. Western utilizes this information only to broadly gauge market trends.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 36, a - c
Witness: Gary Smith

a.&b. Based on Western's marketing reports, the following Table is provided regarding residential-new construction additions, Item 36 (a) and conversions, Item 36 (b):

Fiscal	Residential	
Year	New Construction	Conversions
1990	1,225	1,189
1991	1,272	994
1992	1,403	824
1993	1,861	839
1994	2,037	1,026
1995	2,236	1,095
1996	1,466	834
1997	1,744	870
1998	1,783	363
1999	1,715 [1]	318 [1]
2000	1,450 [2]	250 [2]

Notes: [1] - Information for FY 1999 through July 31.
[2] - Forecast growth rates represent net annual additions, inclusive of any customer losses that may occur.

c. Western does not possess data that would indicate the percent of new residential construction that utilizes gas service. Western has assessed the residential market saturation for homes located on the Company's gas mains, discovering that 98.5% of those homes utilize gas service (see testimony in the Company's Application, Volume 2 of 10, Tab 11, page 12, lines 14-16). However, new residential developments typically require an extension of gas mains, inside the development, and many times an approach main from Western's existing system to the access the property.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 37
Witness: Smith

Data Request:

Reference Mr. Smith's testimony at page 14, lines 8-10. Please provide the basis of Mr. Smith's testimony. Include all numerical support relied on by Mr. Smith, and please include all workpapers leading to the numerical support relied on by Mr. Smith.

Response:

The rate increases associated with Western's last rate case were phased-in from November 1995 to March 1996. The first full fiscal year for which Western's new rates were in effect was FY1997. Mr. Smith conducted the analysis shown on the following schedule to arrive at his conclusion.

Western Kentucky Gas Company
Initial AG Data Request, dated August 19, 1999
DR Item 37

Line No.	Item	FY 1997	FY 1998	12-mo Ending June 1999	Source
	(a)	(b)	(c)	(d)	(e)
1	Operating Revenues				
2	Gas	136,922,255	114,756,553	94,274,256	Financial Statements
3	Transportation	7,217,347	8,831,519	8,547,393	Financial Statements
4	Total	144,139,602	123,588,072	102,821,649	Financial Statements
5					
6	Purchase Gas Cost	99,081,893	79,995,916	61,970,850	Financial Statements
7					
8	Gross Profit	45,057,709	43,592,156	40,850,799	Financial Statements
9					
10					
11	Weather Statistics				
12	Degree-Days, Actual	4,315	4,013	3,701	NOAA, Composite
13	Degree-Days, Normal	4,340	4,340	4,340	NOAA, Composite
14					
15	Weather Sensitive Volumes				
16	Residential Sales (incl Unbilled)	13,657,999	12,338,322	11,689,716	Financial Statements
17	Commercial Sales	5,977,762	5,604,480	5,139,484	Financial Statements
18	Public Authority Sales	1,531,144	1,461,600	1,344,628	Financial Statements
19					
20	Residential Base Load per Month	252,184	184,980	235,841	Financials, Avg Prior July&Aug
21	Commercial Base Load per Month	183,850	184,273	158,827	Financials, Avg Prior July&Aug
22	Pub. Auth. Base Load per Month	37,051	29,347	34,119	Financials, Avg Prior July&Aug
23					
24	Residential Heating Load/DD	2,464	2,521	2,394	(Line 16-(Line20x12mo))/Line 12
25	Commercial Heating Load/DD	874	846	874	(Line 17-(Line21x12mo))/Line 12
26	Pub. Auth. Heating Load/DD	252	276	253	(Line 18-(Line22x12mo))/Line 12
27					
28	Residential Adjustment - Volume	61,598	824,513	1,529,668	Line 24x(Line 12-Line 13)
29	Commercial Adjustment - Volume	21,851	276,496	558,294	Line 25x(Line 12-Line 13)
30	Pub. Auth. Adjustment - Volume	6,295	90,403	161,468	Line 26x(Line 12-Line 13)
31					
32	Weather Sensitive Margin - Res.	1.0615	1.0615	1.0615	Avg. Commodity Margin, FY1998
33	Weather Sensitive Margin - Com.	0.9873	0.9873	0.9873	Avg. Commodity Margin, FY1998
34	Weather Sensitive Margin - PA.	0.9224	0.9224	0.9224	Avg. Commodity Margin, FY1998
35					
36	Residential Adjustment - Margin	65,386	875,220	1,623,742	Line 28 x Line 32
37	Commercial Adjustment - Margin	21,574	272,985	551,203	Line 29 x Line 33
38	Pub. Auth. Adjustment - Margin	5,807	83,388	148,938	Line 30 x Line 34
39	Total Adjustment - Margin	92,767	1,231,593	2,323,883	Lines 36+Line 37 +Line38
40					
41	Gross Profit (Adjusted for Weather)	45,150,476	44,823,749	43,174,682	Line 39 + Line 8

38

RECYCLED 10% P.C.W.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 38
Witness: Gary Smith

Data Request:

38. Refer to Mr. Smith's testimony at page 14, lines 23-25. Please provide workpapers detailing the calculation of the $1,600,000 amount of annual margin reduction related to the effects of energy efficiency improvements and conservation in core markets.

Response:

Please refer to the response to KPSC Data Request No. 1, dated July 16, 1999, Item 5.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 39
Witness: Gary Smith

Data Request:

39. Refer to Mr. Smith's testimony at page 14, lines 26-30. Explain why the Company would add unprofitable customers when such additions are inconsistent with the Company's Distribution Main Extensions Rules and Regulations that require "... the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditure involved to make the investment economically feasible."

Response:

Through Western's interpretation of the above-referenced tariff statement, the Company expects a customer to have a reasonable consumption level (natural gas heating) in order to qualify for the one hundred (100) foot distribution main extension without charge. Western does not interpret the referenced tariff statement as a means of overcoming inadequate rate design. If the Company interpreted the referenced tariff statement as superceding all other tariff and regulatory main extension requirements, few, if any residential main extensions would be provided without charge.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 40
Witness: Gary Smith

Data Request:

40. Please provide:

- new customer usage;
- estimated service commencement costs;
- equipment requirements (i.e., footage of main service lines, etc.); and
- other information that is routinely provided to management responsible for approving new customer service.

Response:

- New customer usage – See response to AG DR 137 for Western's preliminary report estimating the weather normalized consumption of recent residential customer additions.

- Estimated service commencement costs – See Mr. Ives' Exhibit DMI-3 and Mr. Doggette's Exhibit's DHD-2.

- Equipment requirements – See Mr. Ives' Exhibit DMI-3.

- Other information that is routinely provided to management responsible for approving new customer service. – See response to AG DR 43 for example of typical information provided to managers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 41, a - d
Witness: Gary Smith

Data Request:

41. Refer to Mr. Smith's testimony at pages 16-17, lines 20-30 and 1-12, respectively.

a. Please provide the volumes Mr. Smith believes are at risk from physical bypass.

b. Please provide the volumes Mr. Smith believes are at risk from shifts in production to sister plants outside of western Kentucky.

c. Please provide the volumes Mr. Smith believes are at risk from alternate fuel competition. What alternate fuels?

d. Please provide the delivered gas price that Mr. Smith believes is necessary to compete with each alternate fuel identified in c. above.

Response:

a. Western cannot accurately quantify the total load that is at risk from physical bypass.

What is known is the volume under special contracts entered into in response to known bypass threats. As shown on Exhibit GLS-1, column (d), line 31, the volume under special contracts during fiscal year 1998 was 13,230,373 Mcf. Contract volume adjustments of 101,730 Mcf were added in column (f) of Exhibit GLS-1, and in the response to the KPSC's second Data Request, Item 47 a, Western identified 2,781,219 Mcf served under tariff rates in fiscal year 1998, but expected to be under special contract rates in the test year of 2000.

Thus, the test year includes a total of 16,113,322 Mcf under special contract rates. This represents 57% of Western's total industrial sales and transportation deliveries during the test year.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 41, a - d
Witness: Gary Smith

One difficulty in assessing Western's volumes vulnerable to physical bypass beyond those under special contracts is that competitive conditions can change. For example, individual customers, whose current consumption alone would not appear to warrant their investment in bypass facilities, could unexpectedly join forces with neighboring industries to economically justify shared facilities.

Regardless, however, of Western's inability to quantify this vulnerability, it is our belief that, under current market conditions and proposed tariff transportation rate schedules, the volumetric risk for bypass threats among tariff customers is much less than those volumes already served by Western under special contracts.

b. Western is unable to quantify the volumes at risk from shifts in production to sister plants outside of western Kentucky. It is Western's belief, however, that the vast majority of its industrial customers are at risk of lost production - either to internal ("sister") facilities or to external competitors.

c. Western faces alternate fuel competition with coal, fuel oil, propane and electricity. In the case of electric competition, an industry would typically have to replace existing natural gas fueled equipment with electric equipment. The vulnerability to electric competition, due to the breadth of applications and uncertainty regarding future technological advances, is difficult to quantify.

Several of Western's industrial and large commercial customers maintain alternate fuel facilities that can readily displace their natural gas requirements. These customers, who possess coal, fuel oil or propane as an alternative to natural gas comprise approximately 20,000,000 Mcf of Westerns total test year throughput (41%).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 41, a - d
Witness: Gary Smith

d. Western is unable to calculate the delivered natural gas price necessary to compete with each of the identified alternate fuels. Further, it is unlikely that a single such price versus a given fuel alternative would apply to each industry. Westerns service area overlays with several electricity providers, competing with an assortment of delivered power prices to our industrial market. The prices for oil, coal and propane are not regulated and, therefore, would vary from customer to customer.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 42
Witness: Gary Smith

Data Request:

42. Reference Mr. Smith's testimony at page 17, lines 26-27. Please provide the amount of stranded costs associated with the loss of the referenced customers. If Mr. Smith believes there no costs stranded that were necessary to provide service to the referenced customers, please provide Mr. Smith's explanation for this.

Response:

Fortunately, in the two cases where Western experienced bypass by large consumers, little, if any, stranded costs were associated. The only facilities that were rendered unnecessary after the loss of these customers were the delivery stations serving the plants. The metering and pressure regulation equipment was removed from service at the delivery site, and utilized elsewhere on Western's system.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 43
Witness: David H. Doggette

Data Request:

43. For the ten largest Company construction projects to provide service to new customers (as opposed to construction projects related to maintenance) since 1995, please provide the information provided to managers responsible for the approval of such projects.

Response:

The ten largest construction projects to provide service to new customers since 1995 have been completed. During the project completion process, the project approval documents are combined with the project completion records and those records are retained and filed. Attached are copies of the records as filed.

04/15/96 17:36:54 CAPITAL APPROPRIATION GENERATION SYSTEM CAG400
ENTRY: 02/15/96 1996 AFE REQUEST FORM WITH DETAIL STATUS: A
TYPE: N

NUMBER: U03834-001 TITLE: 292 - [redacted]

P/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
DATE/DIV: 9 WKG
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 292 RURAL HENDERSON CO
LINE NO.: 9515-292 ADDRESS: HENDERSON CO RURA

CONTRACT: N/A
START DATE: 2/19/1996 COMPLETE DATE: 5/1/1996

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	916559	36900	10	0	140,658	0	140,658-	140,658
REGULATOR STATION								
REGULATORS& RELIEF VALVE								6,900
STATION VALVES								10,280
ODORIZING VALVE, ODORIZER & EQUIPMENT								2,550
RECORDING GUAGE								1,200
MATERIALS AND EXPENSES								3,000
STORES EXPENSE 25%								5,235
COMPANY LABOR								1,005
CONTRACT LABOR								8,500
SUPPLIERS STATION								90,000
16.00 % NSOCCC								6,187
15.00 % A & G								5,801
,	916560	37601	10	0	111,725	0	111,725-	111,725
4" MAIN								
990' 4" STEEL								3,119
10,400' 4" POLY PIPE								15,080
STORES EXPENSE 25%								4,550
OTHER MATERIALS								4,399
CONTRACT LABOR								48,138
RIGHT-OF-WAYS								5,600
ENGINEERING AND INSPECTION								2,900
COMPANY LABOR								1,500
16.00 % NSOCCC								13,646
15.00 % A & G								12,793

RED APPROVAL AMT: 252,383 NORMAL APPROVAL AMT: 0

DESCRIPTION:
THIS SALES STATION AND MAIN EXTENSION IS TO SERVE THE [redacted] PLANT JUST [redacted].
THE AFE INCULDES PLAN A, WHICH CONSISTS OF THE SUPPLIERS STATION, PURCHASE STATION, 990' OF 4" STEEL PIPE AND 10,400' OF 4" POLY PIPE.
THE SUPPLIERS STATION AND THE PURCHASE STATION WILL BE LOCATED AT THE TEXAS GAS TRANSMISSION LINES WHICH CROSSES THE [redacted]
THE 4" STEEL PIPE WILL BE INSTALLED STARTING AT THE PURCHASE STAION AND EXTENDING 990' TOWARD THE [redacted] THE 4" POLY PIPE WILL EXTEND FROM THE PURCHASE STATION 10,400' TOWARD THE [redacted]

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: 0

STATUS NAME DATE TIME

CURRENT USER: ROBERT F STEPHENS

APPROVED ROBERT F STEPHENS 3/20/96 13:35

APPROVED JOHN CHARLES GOODMAN 3/20/96 10:51
BOB, I CONCUR AND RECOMMEND APPROVAL.

APPROVED DAN L LINDSEY 3/8/96 16:37
I RECOMMEND APPROVAL. DESIGN LOOKS GOOD. CONTRACT IS SIGNED AND ECONOMICS LOOK GOOD. THIS WAS REJECTED AS A 1996 BUDGET PROJECT BECAUSE OF UNCERTAINTY AT BUDGET TIME.

APPROVED ROBERT EARL FISCHER 3/5/96 16:38
RECOMMEND APPROVAL. RETURN ON INVESTMENT IS 6.3 YEARS, PLUS BACKUP GUARANTEE OF RECOVERY OF ASSETS IN THE EVENT OF BYPASS AFTER CONTRACT PERIOD.

APPROVED ROY D PEARSON 3/5/96 12:57
I RECOMMEND APPROVAL OF THIS REQUEST, WE WOULD LIKE TO START CONSTRUCTION AS SOON AS THE WEATHER AND WORKING CONDITIONS ARE SUITABLE.

SENT JAY F CARNAHAN 3/5/96 09:57
CONTRACTS HAVE BEEN EXECUTED BY THE CUSTOMER AND THE COMPANY. CONTRACT HAS FINANCIAL PROTECTION FOR RECOVERY OF ASSETS SHOULD CUSTOMER ELECT TO BYPASS COMPANY AT END OF PRIMARY (5-YEAR) TERM OF AGREEMENT. I CONCUR AND RECOMMEND APPROVAL OF THIS REQUEST.

SENT ROY D PEARSON 3/4/96 17:48
FOR YOUR REVIEW AND COMMENTS.

SENT DAVID H DOGGETTE 3/4/96 15:25
I RECOMMEND APPROVAL. DUE TO PHIL SPRINGER BEING OUT OF THE OFFICE, I AM RETURNING THIS TO YOU. DAN LINDSEY HAS SEEN THIS REQUEST, BUT MAY WANT PHIL TO ANALYZE IT FURTHER UPON HIS RETURN.

SENT JAMES L SMITH 3/4/96 13:52
AGREE WITH STATION(S) AS PLANNED. RECOMMEND FOR APPROVAL.

SENT DAVID H DOGGETTE 3/4/96 10:25
PLEASE PROVIDE SUB-BUDGET REVIEW FOR ACCT. 36900, SUB-BUDGET 11.

SENT DAN L LINDSEY 3/1/96 11:23
BACK TO YOU FOR REINSERTION INTO APPROVAL PATH.

SENT LARRY J MOORE 3/1/96 09:50
STATUS: CONTRACTS HAVE BEEN SIGNED BY CUSTOMER AND ARE WAITING FOR EARL FISCHER'S SIGNATURE. THE ROR IS 12.1, 12.3, 13.6, 16.3, 18.8 FOR YEARS ONE THROUGH FIVE. THE INVESTMENT WILL BE RETURNED IN 6.3 YRS.MNTHS.

SENT PHILLIP W SPRINGER 2/29/96 07:53
PLEASE ADD COMMENTS REGARDING ECONOMICS OF THIS RED PROJECT AS NONE ARE INCLUDED IN THE PACKET SENT ME. ALSO, PLEASE ADD COMMENTS REGARDING STATUS OF CONTRACTS. PLEASE RETURN AFE TO ME FOR COMMENT AFTER YOUR REVIEW.

SENT DAVID H DOGGETTE 2/23/96 13:30
FOR YOUR REVIEW AND COMMENTS. A HARD COPY OF DOCUMENTATION WAS SENT TO YOU AND SHOULD ARRIVE TODAY. AFTER YOUR REVIEW, YOU MAY WANT TO HAVE MARKETING PERSONNEL COMMENT ON THE ECONOMIC ANALYSIS FOR THIS PROJECT. PLEASE HAVE THIS REQUEST ROUTED BACK TO 'DOGGETTE' FOR FURTHER PROCESSING.

SENT ROY D PEARSON 2/22/96 07:29
PLEASE REVIEW AND COMMENT.

APPROVED ROGER L GARMS 2/21/96 16:13
RECOMMEND APPROVAL.

SENT GARY L SMITH 2/21/96 13:18
WKG HAS WORKED INTENSIVELY WITH [redacted] TO RESOLVE SERVICE/CONTRACT ISSUES OVER THE PAST SEVERAL MONTHS, FACING EXTREME COMPETITION FROM OTHER PARTIES ON THIS PROJECT. WE'VE SECURED AN EXECUTED TARIFF AGR. EFFECTIVE IMMEDIATELY AND A REPLACEMENT SPECIAL CONTRACT SPECIFYING NON-TARIFF RATES FOR TRANSPORTATION SERVICE (REQUIRES KPSC APPROVAL). THE AGREEMENTS AFFORD PROTECTION TO WKG FOR ANY COSTS INCURRED SHOULD

FERC DENY THE TAP TO BE REQUESTED BY TEXAS GAS. THE SPECIAL CONTRACT RATES PRODUCE A FAVORABLE RETURN TO WKG AND RECOVERY OF THIS INVESTMENT. [redacted] EXPECTED TO CONSUME OVER 1,000,000 MCFY AT FULL PRODUCTION, DESIRES GAS FOR TESTING PURPOSES AS SOON AS IT'S ACHIEVABLE.

SENT ROGER L GARMS 2/19/96 13:09

PLEASE REVIEW AND COMMENT.

APPROVED JIMMIE C BOURLAND 2/19/96 11:28

TECHNICAL REVIEW HAS BEEN COMPLETED.

SENT GENE R BAKER 2/19/96 10:23

TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.

SENT BELINDA J BELL 2/19/96 08:27

RECOMMEND APPROVAL. THIS PURCHASE STATION AND 4" MAIN IS REQUIRED TO SERVICE THE [redacted] PRESSURE AND LOAD REQUIREMENTS.

SENT JIMMIE C BOURLAND 2/15/96 16:31

FOR TECHNICAL REVIEW.

SENT EDDIE G HAZZARD 2/15/96 16:12

PLEASE REVIEW.

DISTRIBUTION: NELSON GARMS HAZZARD FOGLE KRAMER BOURLAND

INSTRUCTIONS:

THIS IS THE ORIGINAL AFE. PLEASE SIGN THIS DOCUMENT AND RETURN TO PLANT ACCOUNTING.

09/27/95 17:37:24 CAPITAL APPROPRIATION GENERATION SYSTEM CAG400
ENTRY: 08/04/95 1995 AFE REQUEST FORM WITH DETAIL STATUS: R
TYPE: N

NUMBER: 208507-001 TITLE: 292-[redacted]

SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
STATE/DIV: 9 WKG
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 292 RURAL HENDERSON CO
LINE NO.: 9515-292 ADDRESS: HENDERSON CO RURA

CONTRACT: N/A
START DATE: 8/14/1995 COMPLETE DATE: 9/14/1995

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
R		37601	10	200,000	0	0	200,000	126,938
	1000' 4" POLY							
	880' 4" STELL X42, .188WT PEBFW, DRL, FBE							2,728
	STORES EXPENSE							955
	11,830 4" POLYETHYLENE PIPE							17,299
	STORES EXPENSE							6,055
	OTHER MAT'LS							2,330
	STORES EXPENSE							816
	R/O/W							6,660
	CONTRACT LABOR							51,457
	COMPANY LABOR							2,370
	21.00 % NSOCCC							19,041
	19.00 % A & G							17,227
R		38000	10	0	0	1,051	1,051-	1,051
	880" 4" STEEL & 10,930 4" POLY							
	100' 4" POLYETHYLENE PIPE-SERVICE LINE							750
	21.00 % NSOCCC							158
	19.00 % A & G							143
R		38500	10	0	0	106,531	106,531-	106,531
	STATION,REGULATORS AND TAP FEE							
	4-2" REGULATORS ANSI 600							3,300
	5-2" VALVES ANSI 600 (1440 WOG)							3,375
	1-2" REGULATOR							750
	1-4" ODORIZING VALVE ANSI 150 & ODORIZING TANK WITH EQUIP.							2,475
	1-RECORDING GAUSE							1,200
	REGULATOR SETS AT PLANTS							2,400
	OTHER MATERIALS							1,500
	CONTRACT LABOR							5,000
	TAXES GAS TAP FEE							75,000
	STORES EXPENSE							2,022
	21.00 % NSOCCC							4,730
	19.00 % A & G							4,279

REQ APPROVAL AMT: 107,582 NORMAL APPROVAL AMT: 126,938

DESCRIPTION:
IT IS PROPOSED TO SUPPLY GAS TO [redacted] IN THE ROBARDS COMMUNITY FROM A SINGLE

TAP ON A TEXAS GAS PIPELINE LOCATED ON THE PROCESSING PLANT PROPERTY. THE TEXAS GAS TAP WILL BE LOCATED APPROXIMATELY 820' WEST OF THE [redacted] PLANT AND APPROXIMATELY 11,990' NORTH OF THE [redacted]. THERE WAS NO SITE PLAN PROVIDED AND THIS AFE IS BASED ON A SURVEY OF A DISTRIBUTION LAYOUT CONDUCTED BY THE OWENSBORO ENGINEERING DEPARTMENT.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 91702 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER: ROBERT EARL FISCHER			
REJECTED	ROBERT EARL FISCHER	9/27/95	11:31
PULLBACK	ROBERT EARL FISCHER	9/27/95	11:30

THIS PROJECT IS STILL IN THE NEGOTIATING STAGE AND THE FINAL DETERMINATION OF THE SUPPLIER HAS NOT BEEN MADE. IF THE PROJECT IS AWARDED TO WKG IN THE 1996 FISCAL YEAR, IT WILL BE RE-SUBMITTED AT THAT TIME.

APPROVED	ROBERT EARL FISCHER	9/25/95	09:39
APPROVED	ROY D PEARSON	9/21/95	16:13

CONSIDERING THE ONGOING DISCUSSIONS RELATING TO NATURAL GAS SERVICE WITH [redacted] I RECOMMEND WE CONTINUE THE APPROVAL PROCESS OF THIS REQUEST; WITH FINAL IMPLEMENTATION DEPENDANT UPON THE EXECUTION OF A SERVICE AGREEMENT. AS NOTED IN CARNAHAN'S COMMENTS, I HAVE HAD CORRECTIONS MADE TO HAVE THE FUNDS APPLIED AGAINST THE CORRECT ACCOUNTS.

SENT JAY F CARNAHAN 9/11/95 11:45

I RECOMMEND APPROVAL WITH EXECUTION OF A SERVICE AGREEMENT BY [redacted]. ALSO, I RECOMMEND WE TREAT THIS INSTALLATION AS A MAIN AND, NOT AS A SERVICE AS INDICATED.

SENT GARY L SMITH 9/8/95 11:33

WE CONTINUE TO HAVE FREQUENT DIALOGUE WITH [redacted] CONCERNING THIS PROJECT. THEY HAVE REQUESTED A DRAFT SVC. AGR. FOR THEIR REVIEW AND INDICATE THAT THEY ARE SERIOUSLY CONSIDERING SELECTING WKG AS TRANSPORTER. THEY TELL US THEY PLAN TO FINALIZE THEIR DECISION AS SOON AS POSSIBLE SO THAT TAP FILINGS AND LINE INSTALLATION CAN PROCEED QUICKLY. WE WILL ENSURE THAT CONTRACTUAL ARRANGEMENTS PROTECTING WKG'S FINANCIAL INVESTMENT WILL BE SECURED PRIOR TO COMMENCEMENT OF CONSTRUCTION.

SENT JAY F CARNAHAN 9/8/95 08:48

PLEASE PROVIDE UPDATE ON STATUS OF CONTRACTUAL AGREEMENT.

SENT DAVID H DOGGETTE 9/6/95 14:02

I AGREE THAT THE LINE, AT LEAST UP TO THE PROPERTY LINE, WOULD BE CONSIDERED A DISTRIBUTION MAIN. IF WE ARE MOVING FORWARD WITH AN AGREEMENT WITH [redacted] PLEASE ADVISE AND I WILL HAVE BAKER MAKE THE NECESSARY ADJUTMENTS.

SENT JAY F CARNAHAN 9/5/95 16:35

I CONCUR WITH THIS LINE BEING A DISTRIBUTION MAIN INSTEAD OF A SERVICE LINE. PLEASE PROVIDE COMMENTS AS TO YOUR OPINION.

SENT ROY D PEARSON 9/1/95 09:52

JAY,WHAT IS THE STATUS OF OUR PROPOSAL TO [redacted] I THINK THIS AFE SHOULD BE A MAIN EXTENSION AND A SERVICE.

APPROVED ROGER L GARMS 8/17/95 14:25

RECOMMEND APPROVAL.

SENT GENE R BAKER 8/17/95 11:03

RECOMMEND APPROVAL. SERVICE TO [redacted] WAS BUDGETED FOR $200,000 AS A MAIN EXTENSION. HOWEVER THE PROPOSAL AND AFE WERE CHANGED TO SERVICE BECAUSE ALL LINES WILL NOW BE DOWNSTREAM OF THE METER. PROJECT SHOULD ONLY BE $33,469 IN RED.

SENT DAVID H DOGGET 8/17/95 08:22

PLEASE REVIEW. ALSO NOTE ACCOUNT NUMBER AND DETERMINE IF FUNDS ARE CODED CORRECTLY. RETURN TO GARMS TO BEGIN APPROVAL PROCESS.

SENT ROGER L GARMS 8/8/95 15:56

FOR TECHNICAL REVIEW AND COMMENTS.

LBACK ROGER L GARMS 8/8/95 15:55

TO RE-ROUTE AFE.

SENT ROGER L GARMS 8/8/95 07:46

FOR TECHNICAL REVIEW AND COMMENTS.

SENT GARY L SMITH 8/7/95 10:55

LVS HAS SUBMITTED TO [redacted] A PROPOSAL FOR SPECIAL RATE TRANSPORTATION SERVICES. IF WE GET THEIR ACCEPTANCE OF THE PROPOSAL, WE ANTICIPATE THAT CONSTRUCTION (AND INTERSTATE TAP FILINGS) WILL NEED TO PROCEED AT A FAST PACE. CONTRACTS TO PROTECT WKG'S FINANCIAL INVESTMENT PRIOR TO SECURING KPSC APPROVAL OF THE NON-TARIFF CONTRACT WILL BE EXECUTED BEFORE COMMENCEMENT OF CONSTRUCTION.AS NOTED, FACILITIES DESIGN IS CONTINGENT ON [redacted] ACCEPTANCE OF PIPING ROUTE ALONG THEIR PROPERTY AND, THEREFORE, IS SUBJECT TO CHANGE AT THIS POINT.

SENT ROGER L GARMS 8/7/95 09:37

PLEASE REVIEW AND COMMENT.

APPROVED JIMMIE C BOURLAND 8/7/95 08:33

THIS AFE IS NECESSARY TO SUPPLY GAS TO [redacted] THIS IS A 1995 BUDGET ITEM.

SENT EDDIE G HAZZARD 8/4/95 14:04

THE ENGINEERING DEPARTMENT IN OWENSBORO PROVIDED THE INFORMATION FOR THIS AFE. AFTER TALKING WITH GENE BAKER, IT WAS DECIDED THAT THE ACCOUNT SHOULD BE CHANCED FROM REVENUE EXTENSIONS, TO SERVICES DUE TO BILLING METER BEING LOCATED AT TEXAS GAS TAP.

TRIBUTION: NELSON GARMS HAZZARD FOGLE KRAMER BOURLAND

NSTRUCTIONS:

[redacted] PIPE & PRESSURE STUDY

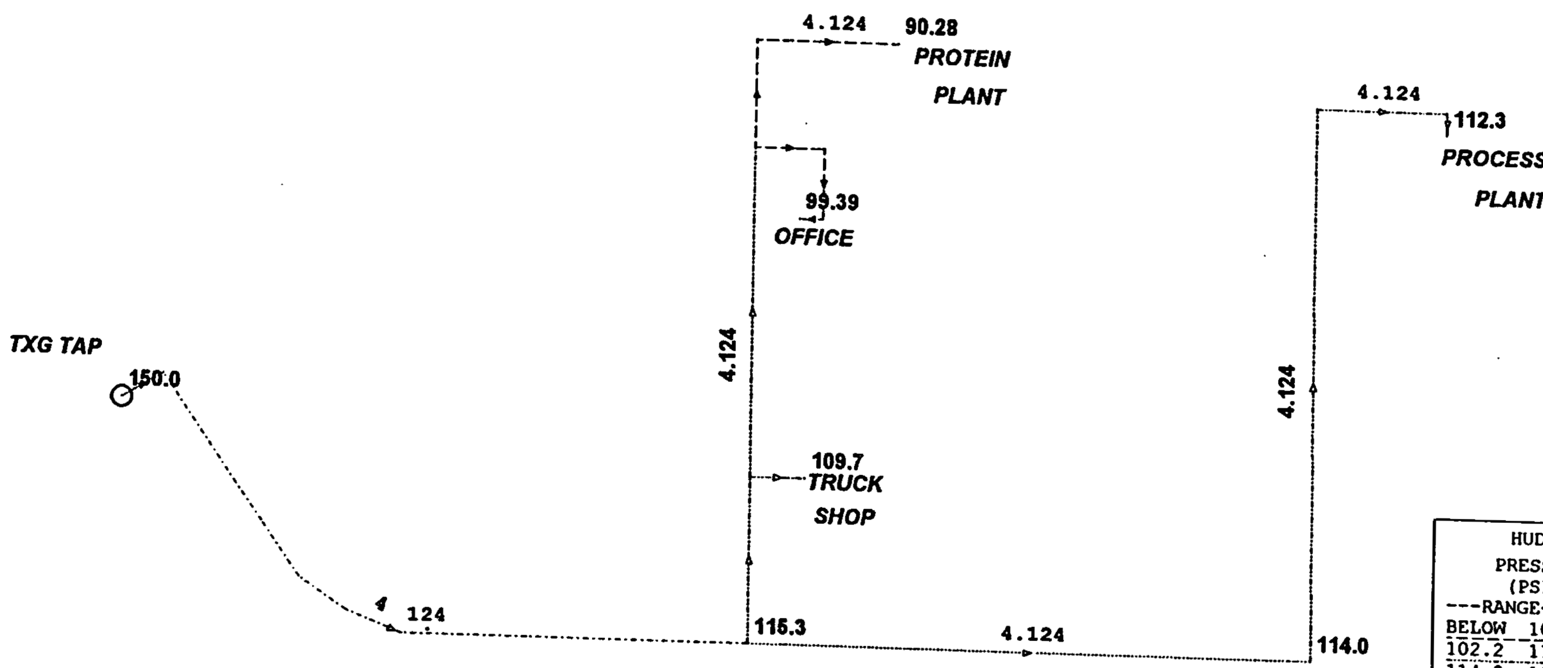
THESE FLOW STUDIES WERE RUN TO DETERMINE REQUIRED OUTLET PRESSURES AND PIPE SIZES TO SERVE THE [redacted] PROCESS PLANT AND [redacted] WITH A MINIMUM OF 30 PSI BASED ON THE LOADS THEY PROVIDED WKG.

THE PROCESS PLANT FLOW STUDY WAS BASED ON AN OUTLET PRESSURE AT THE TEXAS GAS TAP OF 150 PSI. 4" STEEL MAIN WILL ADEQUATELY SERVE BOTH PRESENT AND PROJECTED FUTURE LOAD AND PRESSURE REQUIREMENTS FOR THE PLANT. 3/4" SERVICE LINES COMING OFF OF THE 4", WILL SUFFICIENTLY SERVE THE OFFICE AND TRUCK SHOP. THE LARGEST LOAD ON THE SYSTEM IS AT THE [redacted] BASED ON THE ABOVE MENTIONED PRESSURE AND PIPE SIZE, THE PRESSURE AT THE PLANT WILL BE APPROXIMATELY 90 PSI AT PRESENT AND 80 PSI WITH THE ADDED FUTURE LOAD.

THE GRAIN DRYER FLOW STUDY WAS BASED ON AN OUTLET PRESSURE OF 65 PSI AND 4" P.E. MAIN. GIVEN A PEAK LOAD DEMAND OF 53 MCFH, ABOUT 41 PSI WILL BE REACHING THE GRAIN DRYER AND BOILER. DURING AN AVERAGE OPERATIONAL LOAD OF 30 MCFH, A MINIMUM OUTLET PRESSURE OF 50 TO 55 PSI WILL BE SUFFICIENT TO PROVIDE PRESSURES AT THE DRYER OF 40 AND 46 PSI RESPECTIVELY.

CONCLUSION: 4" STEEL MAIN WILL ADEQUATELY SERVICE THE LOAD AND PRESSURE REQUIREMENTS OF THE PROCESS PLANT BOTH PRESENT AND FUTURE. DURING PEAK LOAD DEMAND OF 53 MCFH AT THE GRAIN DRYER AND BOILER, A MINIMUM OUTLET PRESSURE OF 65 PSI WILL BE REQUIRED TO PROVIDE ADEQUATE PRESSURE. DURING AN AVERAGE OPERATIONAL LOAD OF 30 MCFH, MINIMUM OUTLET PRESSURE RANGING FROM 50 TO 55 PSI WILL BE SUFFICIENT TO SERVICE THE GRAIN DRYER AND BOILER.

[redacted] FOODS
PROCESSING PLANT



HUDSONPP
PRESSURE
(PSIG)

---RANGE----		COUNT
BELOW	102.2	5
102.2	114.2	6
114.2	126.1	1
126.1	138.1	1
ABOVE	138.1	1

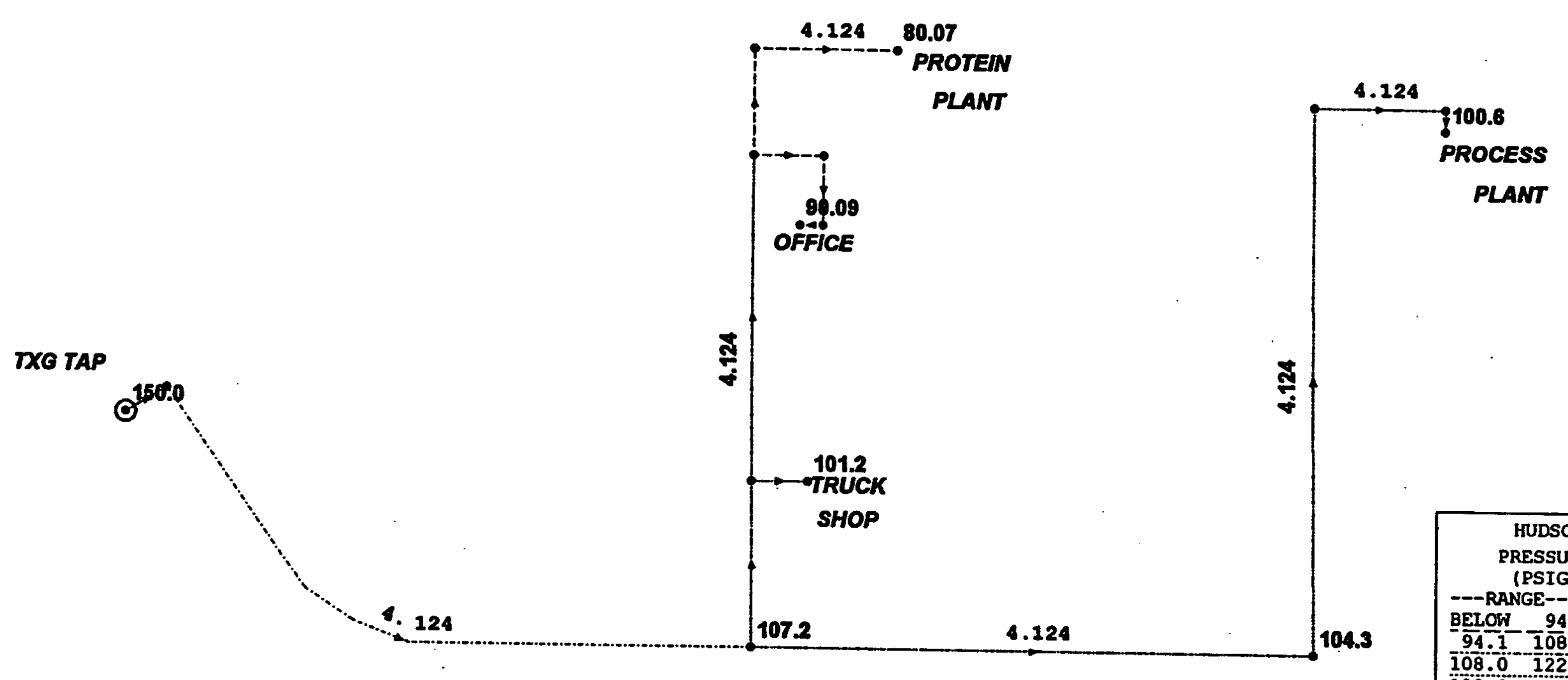
MIN = 90.28
MAX = 150.00
NODE ANN:PRES
ELEM ANN:ID

State: BALANCED

Nov 20, 1995

Corners: (FEET)
UL:(-562,1166)
LL:(-562,-202)
UR:(1331,1166)
LR:(1331,-202)

[redacted] FOODS
PROCESSING PLANT (FUTURE)



HUDSONPP
PRESSURE
(PSIG)

---RANGE----		COUNT
BELOW	94.1	5
94.1	108.0	7
108.0	122.0	0
122.0	136.0	1
ABOVE	136.0	1

MIN = 80.07
MAX = 150.00
NODE ANN:PRES
ELEM ANN:ID

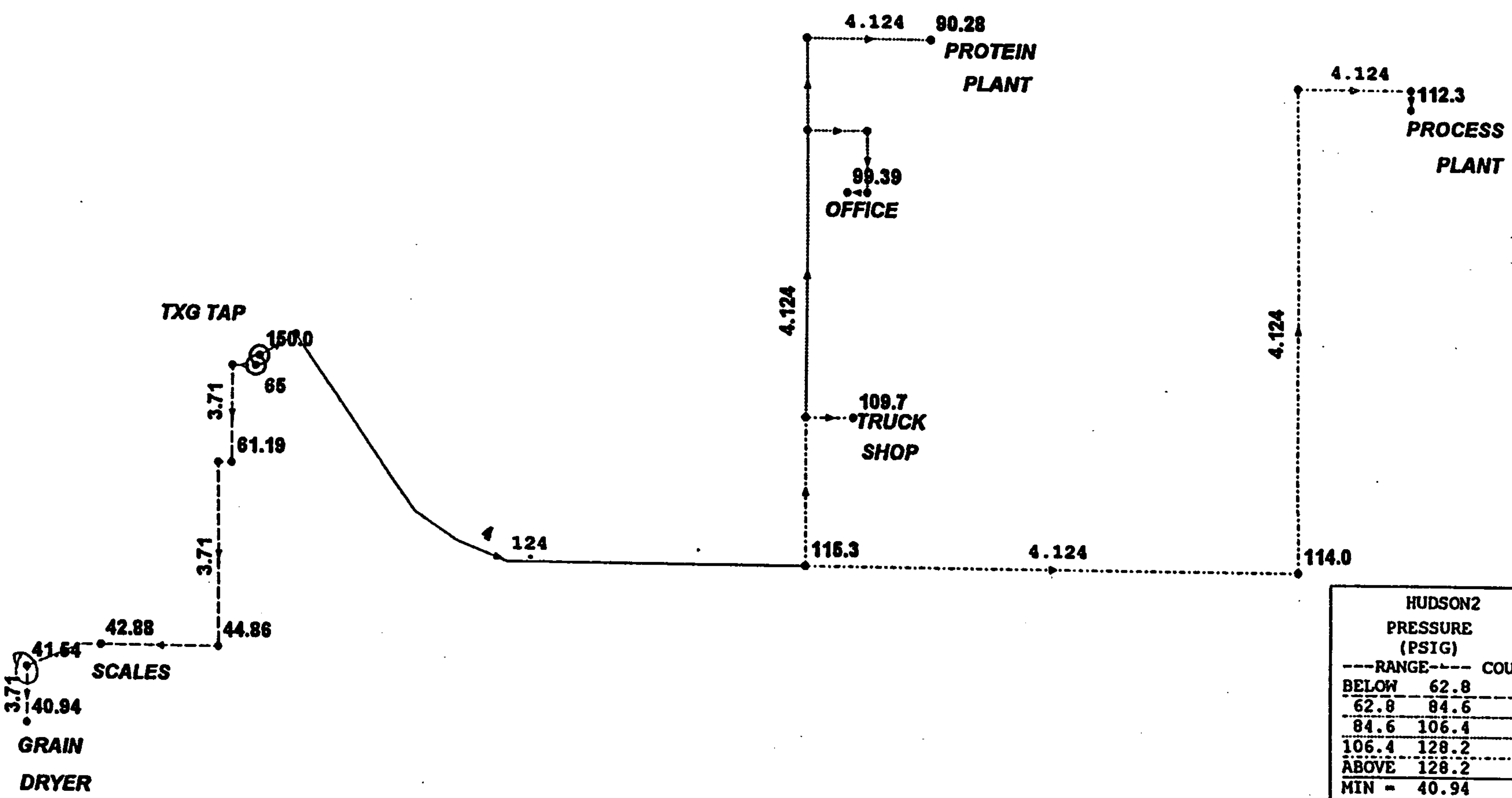
State: BALANCED

Feb 19, 1996

Corners: (FEET)
UL:(-562,1166)
LL:(-562,-202)
UR:(1331,1166)
LR:(1331,-202)

[redacted] FOODS

PROCESSING PLANT AND FEED MILL (PEAK LOAD)



HUDSON2
PRESSURE
(PSIG)

---RANGE---		COUNT
BELOW	62.8	6
62.8	84.6	1
84.6	106.4	6
106.4	128.2	6
ABOVE	128.2	2

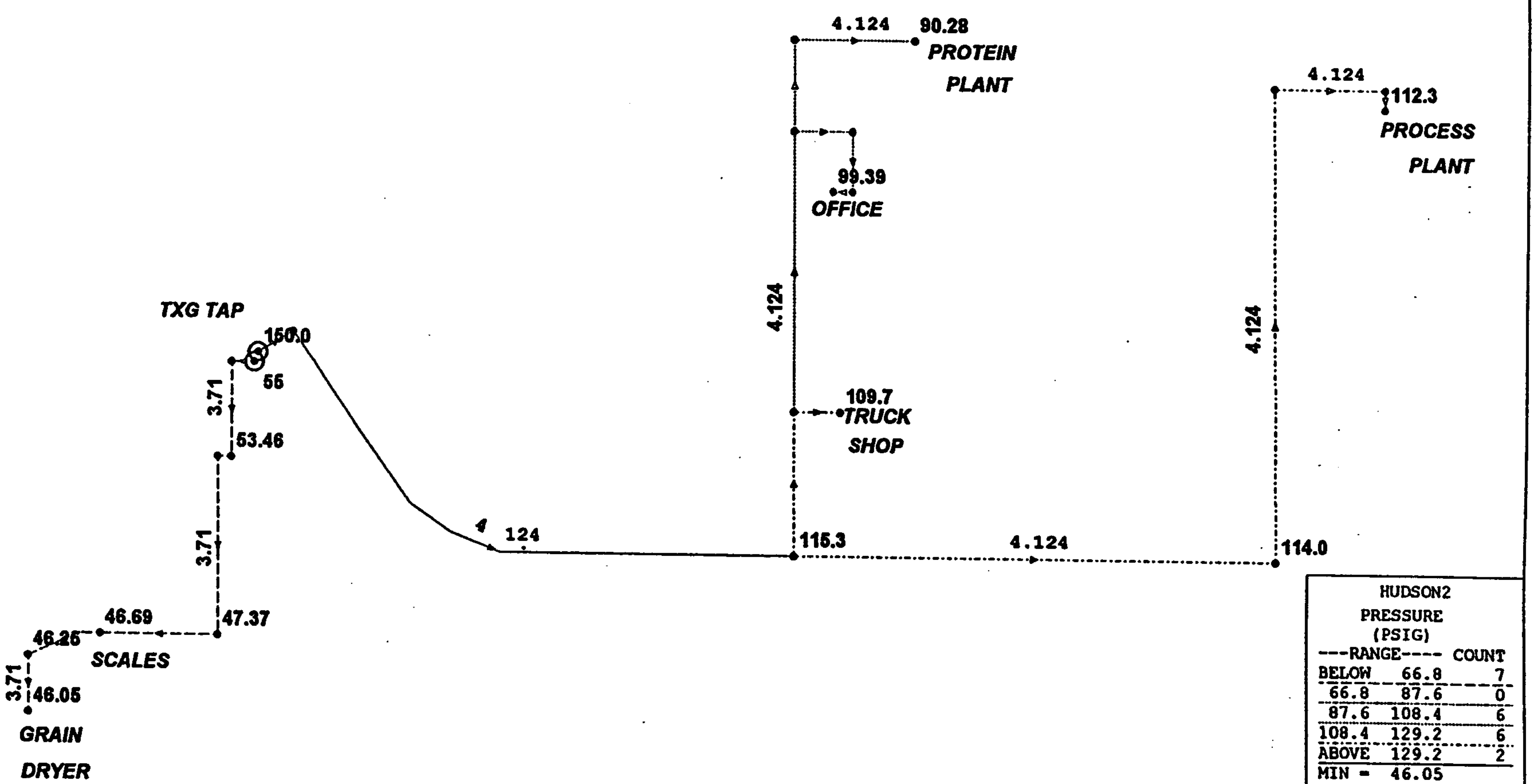
MIN = 40.94
MAX = 150.00
NODE ANN:PRES
ELEM ANN:ID

State: BALANCED

Nov 22, 1995

Corners: (FEET)
UL: (-738,1026)
LL: (-738,-411)
UR: (1251,1026)
LR: (1251,-411)

[redacted] FOODS
PROCESSING PLANT AND FEED MILL (AVG. LOAD)



HUDSON2
PRESSURE
(PSIG)

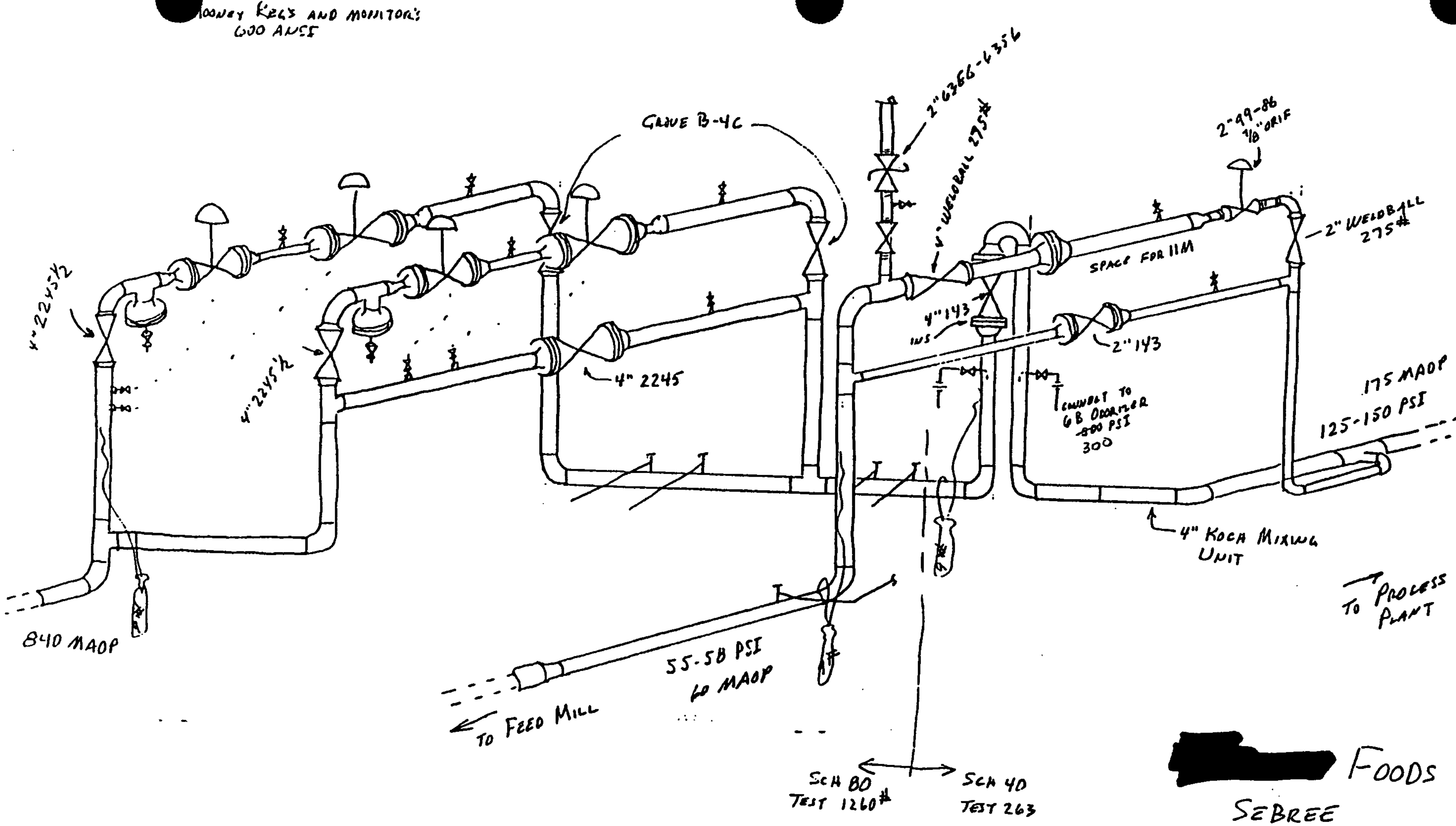
---RANGE----		COUNT
BELOW	66.8	7
66.8	87.6	0
87.6	108.4	6
108.4	129.2	6
ABOVE	129.2	2

MIN = 46.05
MAX = 150.00
NODE ANN:PRES
ELEM ANN:ID

State: BALANCED

Nov 22, 1995

Corners: (FEET)
UL:(-738,1026)
LL:(-738,-411)
UR:(1251,1026)
LR:(1251,-411)



Mooney Regs and Monitors
600 ANSI
4" 2245½
4" 2245½
Grove B-4C
4" 2245
2" 6366-6356
4" Weldball 275#
4" 143
INS
2" 143
2" 99-86
1/8" orif
2" Weldball
275#
Space for 11M
Connect to
GB Odorizer
800 PSI
300
175 MAOP
125-150 PSI
4" Koch Mixing
Unit
To Process
Plant
840 MAOP
55-58 PSI
60 MAOP
To Feed Mill
Sch 80
Test 1260#
Sch 40
Test 263
[redacted] Foods
Sebree

WESTERN KENTUCKY GAS COMPANY
[redacted], INC. "A"
ESTIMATE UTILIZING ONE TAP

PIPELINE FACILITIES DESIGNED FOR 150 & 60 PSI Item	Qty.	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	2	Days	$	225.00	$	450
Acquisition Easement	300	Rods		5.00		1,500
Damages, Crops, Timber, Road, etc.	300	Rods		5.00		1,500
Permits, Filing & Recording Fees	10	Each		15.00		150
Railroad Crossing Permit	1	Each		2,000.00		2,000
				Total R-O-W	$	5,600
PIPELINE MATERIALS						
4" Pipe, Gr. X42, .188 WT, PEBFW, DRL Joints, FBE Coated	990	Lin. Ft.	$	3.15	$	3,119
4" Pipe, Plastic SRL Joints	10,400	Lin. Ft.	$	1.45	$	15,080
4" Line Valve, ANSI 150 (175 WP)	2	Each		1,000.00		2,000
4" Weld Fittings	6	Each		20.00		120
4" Trans Fittings	4	Each		33.00		132
Joint Wrap - Tape	10	Roll		12.10		121
- Primer	1	Gallon		24.21		24
Anodes - 17 lb.	2	Each		47.90		96
Cathodic Protection Test Station	0	Each		17.20		0
2" Blow-off Valves	0	each		275.00		0
2" Blow-off and Vent Piping	0	Lin. Ft.		3.50		0
Marker Post and/or Sign	25	Each		16.25		406
Misc. Materials & Expendables	1	Lump		1,500.00		1,500
	Total Pipeline Materials				$	22,598
PURCHASE STATION MATERIALS						
2" Regulators ANSI 600	4	Each		1,200.00		4,800
2" Reg., Fisher 99, (400 WOG)	1	Each		850.00		850
4" Valves,Ball ANSI 600 (1440 WOG)	5	Each		1,900.00		9,500
2" Valve, Ball, ANSI 150	3	Each		160.00		480
4" Valve, Ball, ANSI 150	1	Each		300.00		300
2" Relief Valve	1	Each		1,250.00		1,250
4" Odorizing Valve ANSI 150	1	Each		250.00		250
Odorizer & Equip.	1	Lump		2,300.00		2,300
Recording Gauge	1	Each		1,200.00		1,200
Misc. Materials & Expendables	1	Lump		3,000.00		3,000
	Total Station Materials				$	23,930
	Total Materials				$	46,528

WESTERN KENTUCKY GAS COMPANY
[redacted] INC. "A"
ESTIMATE UTILIZING ONE TAP

PIPELINE FACILITIES DESIGNED FOR 150 & 60 PSI Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
Install 4" Line Pipe	990	Lin. Ft.	$	4.20	$	4,158
Install 4" Plastic Line Pipe	10,400	Lin. Ft.	$	3.30		34,320
Pipe Fitting and Extra Labor for Creek Crossing	1	Lump		1,000.00		1,000
ROW Clearing	1	Lump		1,000.00		1,000
Boring and Tunneling	740	Lin. Ft.		6.93		5,128
Pressure Testing & De-watering, Sections	1	Lump		1,000.00		1,000
Install Cathodic Protection	2	Each		16.00		32
Building Reg. Stations	1	Lump		8,500.00		8,500
Extra Work	1	Lump		1,500.00		1,500
				Total Con. Labor	$	56,638
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	1	Lump	$	550.00	$	550
Field Inspection	1	Lump		1,500.00		1,500
Pigging and Testing	1	Lump		850.00		850
				Total Eng. & Insp.	$	2,900
				PROJECT SUB-TOTAL	$	111,666

OVERHEADS		
25 % Stores	$	11,632
22.71 % Labor Overhead	$	659
16 % WKG Overhead	$	19,833
15 % Corporate Overhead	$	18,593
FACILITIES TOTAL	$	162,383
SUPPLIERS STATION	$	90,000
PROJECT TOTAL	$	252,383

760100485
960100487

*** Transferred From: BOURLAND - BOURLAND, JIM; 12/28/95 [illegible]
*** Original Author: FISCHER - FISCHER, R. EARL; 12/27/95 [illegible]

12/27/95 CAPITAL APPROPRIATION GENERATION SYSTEM [illegible]
ENTRY: 11/10/95 AFE HAS RCVD FINAL APPRVL BY: ROBERT EARL FISCHER STATUS: [illegible]
FISCAL YEAR: 1996 TYPE: [illegible]
NUMBER: 209353-002 224-[redacted] MAIN EXTENSION
OP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 224 CADIZ
LINE NO.: 9531-224 ADDRESS: CADIZ
CONTRACT: DEFERRED DEP AGREEM.
START DATE: 12/6/1995 COMPLETE DATE: 12/21/1995

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE (THIS ONE) AMOUNT
A	916308	37602	10	39,406	48,200	0	8,794	48,200

2" & 4" PLASTIC MAIN EXTENSION

2,600' - 4" POLY	[illegible]
7,600' - 2" POLY	[illegible]
25% STORES	[illegible]
OTHER MATERIAL	[illegible]
25% STORES	[illegible]
SUPPLIES & EXPENSES	[illegible]
COMPANY LABOR	[illegible]
CONTRACT LABOR	[illegible]
TRANSPORTATION	[illegible]
CAPITALIZED INTEREST	[illegible]
16.00 % NSOCCC	[illegible]
15.00 % A & G	[illegible]

RED APPROVAL AMT: 8,794 NORMAL APPROVAL AMT: 39,406

DESCRIPTION:
[redacted] DEVELOPMENT CORPORATION OF CADIZ IS CONSTRUCTING AN 18 HOLE [redacted] COMPLETE WITH RESIDENTIAL AND COMMERCIAL DEVELOPMENT SURROUNDING THE SITE. WE PROPOSE TO TIE ONTO THE 4" MAIN AT STA 9+60 ON [redacted] (INSTALLED 8-95 ON APPR #10915742) AND EXTEND THE 4" SOUTH ALONG [redacted] ANOTHER 2,600', ENDING ACROSS THE HWY 68 BYPASS AT STA #35+60. OFF THIS 4" TRUNKLINE, WE PROPOSE TO INSTALL ANOTHER 7,600' OF 2" TO PROVIDE GAS SERVICE TO 109 RESIDENTIAL LOTS ON THE [redacted]. THE 4" TRUNKLINE ALONG [redacted] WILL ALSO MAKE GAS AVAILABLE TO APPROXIMATELY 35 COMMERCIAL LOTS TO THE EAST SIDE OF [redacted] A SURVEY PLAT AND OVERVIEW IS BEING FORWARDED FOR THIS PROJECT. THE INSTALLATION OF THIS 10,200' OF LINE WILL COMPLETE PHASE 2 OF [redacted] DEVELOPMENT. SOMETIME IN 1996, THE DEVELOPER WILL PROBABLY BE READY TO DO PHASE 3. THIS WILL REQUIRE OUR TIEING ONTO THE END OF THE 4" MAIN AT STA 35+60 AND INSTALLING ENOUGH MAIN TO PROVIDE GAS SERVICE TO ANOTHER 26 RESIDENTIAL LOTS TO BE

[illegible]ELOPED ON FARTHER BACK ON THE [redacted] PROPERTY. THE [redacted] WHICH WILL SET NEAR STATION 35+60 WILL BE PROVIDED GAS SERVICE BY PHASE 2 OF THE DEVELOPMENT.

MAP REFERENCE: CADIZ PL #15 INSIDE/OUTSIDE CITY LIMITS: I
TAX AUTHORITY: 93501 CADIZ CTY & COM SCH

CURRENT USER: ROBERT EARL FISCHER
APPROVED ROBERT EARL FISCHER 12/27/95 15:56
APPROVED
APPROVED ROY D PEARSON 12/20/95 16:30
RECOMMEND APPROVAL. DESCRIPTION TELLS THE STORY.
SENT DAVID H DOGGETTE 12/20/95 15:[illegible]7
I CONCUR AND RECOMMEND APPROVAL. THIS REQUEST IS [illegible] BECAUSE
MORE FOOTAGE IS REQUIRED THAN ANTICIPATED DURING THE BUDGET PROCESS.
SENT ROY D PEARSON 12/14/95 11:51
PLEASE REVIEW.
APPROVED ROGER L GARMS 12/13/95 15:00
RECOMMEND APPROVAL.
SENT ALETHA ANN FINLEY 12/12/95 17:[illegible]
[redacted] AND [redacted] OF [redacted] DEVELOPMENT CORPORATION
ARE DEVELOPING 109 RESIDENTIAL LOTS IN [redacted]. THERE ARE
TWO (2) HOMES NOW UNDER CONSTRUCTION AND NEAR COMPLETION AND ONE (1)
THAT WILL BEGIN CONSTRUCTION IN A COUPLE OF WEEKS. THIS MAIN
EXTENSION WILL SERVE GAS TO THE [redacted] AND APPROXIMATELY 35
COMMERCIAL LOTS. PHASE THREE WILL BEGIN SOMETIME IN EARLY SPRING OF
1996. RECOMMEND APPROVAL.
SENT ROGER L GARMS 12/12/95 11:25
PLEASE REVIEW AND COMMENT.
APPROVED JIMMIE C BOURLAND 12/12/95 08:23
FOR YOUR REVIEW. TECHNICAL REVIEW HAS BEEN COMPLETED.
SENT GENE R BAKER 12/11/95 16:06
TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.
SENT BELINDA J BELL 12/11/95 15:42
RECOMMEND APPROVAL. 4" P.E. MAIN WILL BE THE HEADER FEEDING THIS
SYSTEM, WITH 2" P.E. INSTALLED INSIDE THE SUBDIVISION. THIS MAIN
COMBINATION WILL ADEQUATELY SERVICE THIS LOAD.
SENT JIMMIE C BOURLAND 12/1/95 16:51
FOR TECHNICAL REVIEW. THIS IS A 1996 BUDGET ITEM. THE FOOTAGE OF
THIS PROJECT INCREASED WHICH INCREASED THE DOLLAR VALUE ABOVE THE
AMOUNT BUDGETED.
SENT EDDIE G HAZZARD 11/29/95 15:42
THE DEFERRED CONTRACT WAS SIGNED BY [redacted] AND [redacted].
THE AMOUNT OF THE CONTRACT IS $41,922.00. THE SIGN CONTRACT AND OTHER
PAPER WORK HAS BEEN FORWARDED.
SENT GEORGE (GIL) G MORRI 11/10/95 10:57
ONE HOUSE IN THIS DEVELOPMENT WILL BE COMPLETED BY THE FIRST OF THE
YEAR. OTHER HOMES ARE ALSO IN EARLY DEVELOPMENT STAGES. MR. DENNIS
THOMAS, ONE OF THE OWNERS OF THIS DEVELOPMENT SAID THAT APPROXIMATELY
50 OF THESE LOTS ARE ALREADY SOLD.

DISTRIBUTION: NELSON GARMS HAZZARD FOGLE KRAMER BOURLAND

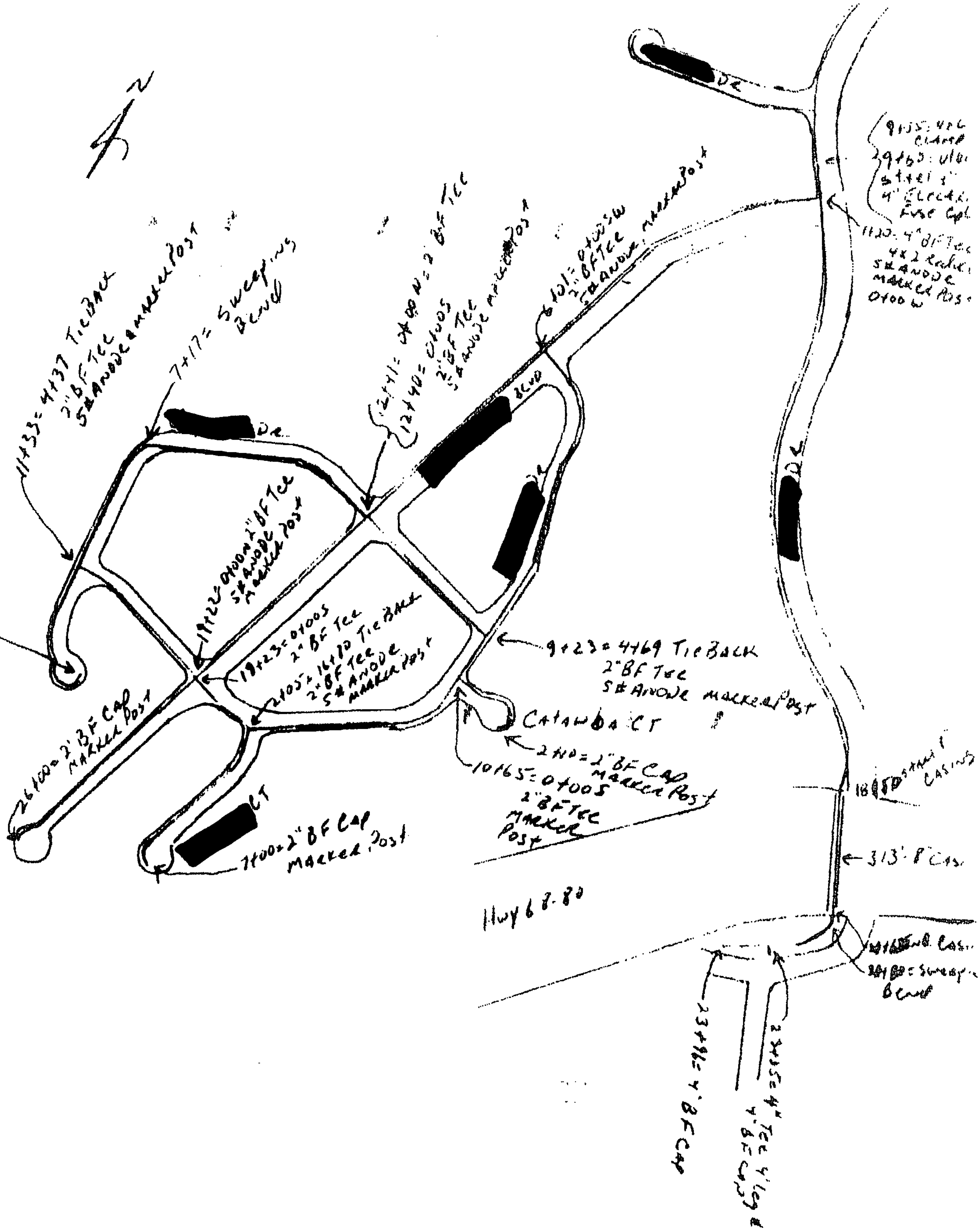
INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT EARL FISCHER .
THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

BY [illegible] DATE 4-9-96 SUBJECT [redacted] Phase II SHEET NO. 1 OF 1

CHKD. BY [illegible] DATE MAIN Extenson JOB NO.

R/W PUBLIC ☑ PRIVATE ☐ TOWN CAdiz PLATE NO. CAdiz 15+20

Utility Easements



11/28/95 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 10/13/95 AFE HAS RCVD FINAL APPRVL BY: JOHN CHARLES GOODMAN STATUS: A
FISCAL YEAR: 1996 TYPE: N
NUMBER: 209864-011 315 - [redacted]EVENUE EXTENSION
JP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 3110100 PADUCAH OFFICE (750)
PROP LOC: 311 PADUCAH
LINE NO.: 9553-315 ADDRESS: LAKE CITY GR RIVE
CONTRACT: DEFERRED DEPOSIT
START DATE: 11/6/1995 COMPLETE DATE: 12/8/1995

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	916303	37602	10	550,000	141,101	60,333	348,566	97,231
315 - [redacted]REVENUE EXT.								
7,230' - 4" P.E PIPE								9,688
STORES EXPENSE								4,360
6,085' - 2" P.E PIPE								3,103
STORES EXPENSE								1,396
OTHER MATERIAL								3,176
STORES EXPENSE								1,429
SUPPLIES AND EXPENSE								5,286
CONTRACT LABOR								37,339
COMPANY LABOR (INCL. 22.71%)								7,257
TRANSPORTATION								1,188
16.00 % NSOCCC								11,876
15.00 % A & G								11,133

ED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 97,231

DESCRIPTION:
THIS EXTENSION WOULD MAKE GAS AVAILABLE TO 160 LOTS IN THIS NEW RESIDENTIAL SUBDIVISION. THIS IS SECTION I OF PHASE I. THERE ARE AN ADDITIONAL 100 LOTS IN PHASE I. THERE ARE APP. 600 RESIDENTIAL LOTS IN THE ENTIRE SUBDIVISION. THIS EXTENSION WILL REQUIRE 7,240' OF 4" P.E PIPE AND 6,085' OF 2" P.E PIPE FOR A TOTAL FOOTAGE OF 13,315'. WE ARE ENTERING INTO A "DEFERRED" DEPOSIT CONTRACT WITH DEVELOPER [redacted]) REPRESENTED BY [redacted]. FUTURE EXTENSIONS ARE CERTAIN. IN ADDITION TO THE RESIDENTIAL LOAD, THERE ARE PROVISIONS BEING MADE FOR APP. 200,000 SQ. FT. OF COMMERCIAL/ RETAIL.

MAP REFERENCE: GRAND RIVERS # 10 INSIDE/OUTSIDE CITY LIMITS: I
TAX AUTHORITY: 92101 GRAND RIVERS CTY & COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	JOHN CHARLES GOODMAN		
APPROVED	JOHN CHARLES GOODMAN	11/28/95	11:27
APPROVED	DAN L LINDSEY	11/28/95	09:27
	I RECOMMEND APPROVAL.		
APPROVED	ROBERT EARL FISCHER	11/28/95	07:07
PPROVED	ROY D PEARSON	11/22/95	14:12

I HAVE REVIEW THIS PROJECT AND TALKED WITH [redacted] THE DEVELOPER SEVERAL TIMES IN THE LAST FIVE MONTHS.THIS WILL BE AN EXCLUSIVE AREA AND SHOULD EXPAND AT A RAPID PACE. THE DEVELOPER UNDERSTANDS OUR DEFERRED DEPOSIT AGREEMENT.I CONCUR WITH THIS REQUEST AND RECOMMEND APPROVAL.

PULLBACK ROY D PEARSON 11/22/95 09:07
FOR REVIEW.
APPROVED ROY D PEARSON 11/15/95 12:26
RECOMMEND APPROVAL.
SENT DAVID H DOGGETTE 11/15/95 08:23
I RECOMMEND APPROVAL.
SENT PHILLIP W SPRINGER 11/14/95 14:10
RECOMMEND APPROVAL. GARY MILLIGAN HAS CONFIRMED THAT ALL CONTRACTS ARE IN ORDER.
SENT LARRY J MOORE 11/14/95 13:44
SENT PHILLIP W SPRINGER 11/10/95 15:40
PLEASE REVIEW AND ADD COMMENTS REGARDING ECONOMICS AND CONTRACTS. NO CONTRACTS OR ECON. WERE INCLUDED IN PACKET FROM WKG.
SENT DAVID H DOGGETTE 11/10/95 12:10
PLEASE REVIEW, COMMENT AND RETURN. ROY PEARSON BRIEFLY MENTIONED THIS PROJECT DURING YOUR RECENT VISIT HERE. I HAD FORWARDED DOCUMENTATION ON THIS PROJECT TO YOU LAST FRIDAY. I AGREE WITH THIS REQUEST AND RECOMMEND APPROVAL.
SENT ROY D PEARSON 11/8/95 15:49
PLEASE REVIEW AND PROVIDE COMMENTS.
APPROVED WINSTON DARRELL MCKE 11/8/95 09:21
APPROVAL REQUESTED.
APPROVED DAVID E RUSSELL 11/8/95 07:39
TECHNICAL REVIEW IS COMPLETE. APPROVAL REQUESTED
APPROVED EDWARD A TUCKER 11/8/95 07:06
CLEARED BY TECHNICAL REVIEW
SENT GENE R BAKER 11/3/95 14:45
TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.
SENT BELINDA J BELL 11/3/95 14:38
RECOMMEND APPROVAL. 4" P.E. MAIN WILL BE RUN DOWN TO THE ENTRANCE OF [redacted] SUBDIVISION. 2" P.E. MAIN WILL BE INSTALLED INSIDE THE SUBDIVISION. THIS COMBINATION OF 2" AND 4" MAIN WILL SERVICE THIS LOAD. THE CONSTRUCTION CONTRACT HAS BEEN SIGNED AND APPROVED. MR. [redacted] HAS ALSO SIGNED THE REIMBURSEMENT CONTRACT WITH WKG. MR. [redacted] WOULD LIKE WKG TO START INSTALLATION AS SOON AS POSSIBLE.
SENT EDWARD A TUCKER 11/2/95 13:06
FOR TECHNICAL REVIEW
SENT TRUDY R WYATT 10/17/95 14:21
DEVELOPER [redacted] IS AN OUTSTANDING BUILDER IN PADUCAH. HIS SUCCESSFUL BACKGROUND BRINGS A WEALTH OF KNOWLEDGE TO THIS EXTENSIVE PROJECT IN THE LAKES AREA. THIS HIGH TRAFFIC PROPERTY WILL RAPIDLY DEVELOP. RECOMMEND APPROVAL. TRUDY WYATT
SENT EDWARD A TUCKER 10/13/95 08:17
PLEASE REVIEW AND COMMENT

DISTRIBUTION: NELSON MCKENNEY RUSSELL ETUCKER BTERRY FOGLE

INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY JOHN CHARLES GOODMAN .

THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

04/18/96 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 10/27/95 AFE HAS RCVD FINAL APPRVL BY: ROBERT EARL FISCHER STATUS: A
FISCAL YEAR: 1996 TYPE: N

NUMBER: 209322-026 411-[redacted] 4" & 2" EXT.
OP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 4110100 BOWLING GREEN OFFICE (760)
PROP LOC: 411 BOWLING GREEN
LINE NO.: 9560-411 ADDRESS: BOWLING GREEN

CONTRACT: NOT REQUIRED
START DATE: COMPLETE DATE:

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	916638	37601	10	750,000	492,838	198,520	58,642	52,438

4848'(4") 2530'(2") PE-[redacted]

4848' OF 4" .395 SDR-11.5 2406 PIPE	6,836
2530' OF 2" .216 SDR-11 2406 PIPE	1,063
STORES EXPENSE 25%	1,975
OTHER MATERIAL	540
STORES EXPENSE 25%	135
SUPPLIES AND EXPENSES	1,000
TRANSPORTATION EXPENSE	50
COMPANY LABOR	200
CONTRACT LABOR	28,230
16.00 % NSOCCC	6,405
15.00 % A & G	6,004

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 52,438

DESCRIPTION:
EXTENSION WILL SERVE A TOTAL OF 81 ELECTRIC AND LP CONVERSIONS THAT HAVE BEEN SURVEYED BY THE MARKETING DEPT. 4" PE TO RUN ON [redacted] LN. AND 2" PE TO RUN ON [redacted], AND [redacted] MAIN WILL PASS BY 23 OTHER HOUSES THAT MAY CONVERT AT A LATER DATE. FUTURE EXTENSION OF THE 4" PE MAKE TIE-INS TO OLD SCOTTSVILLE RD. AND NEW SCOTTSVILLE RD. TO TOWN SYSTEM PROBABLE. NO AGREEMENT REQUIRED PAPERWORK AND MARKETING SURVEY EN-ROUTE TO TECHNICAL SERVICES.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 93605 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT EARL FISCHER		
APPROVED	ROBERT EARL FISCHER	4/18/96	09:10
APPROVED	ROY D PEARSON	4/17/96	12:48

I AGREE WITH THIS REQUESTED EXTENSION AND RECOMMEND APPROVAL.

ENT	KEVIN AKERS	4/16/96	18:50

RECOMMEND APPROVAL OF THE FULL PROJECT INCLUDING THE RED HAVEN COURT FOOTAGE BASED ON CALLS RECEIVED FROM RESIDENTS ON THIS STREET TODAY (04/16/96).

SENT	ROY D PEARSON	4/16/96	09:32

PLEASE REVIEW AND COMMENT.

SENT JUDITH G HAYNES 4/15/96 23:51

I HAVE THE FOLLOWING NUMBER OF YARDLINE ORDERS SIGNED TO BE RUN AS SOON AS THE MAIN EXTENSION IS COMPLETED: [redacted] 47, [redacted] AVE-13, [redacted] CT.-8. THIS REPRESENTS A TOTAL FOOTAGE OF 6624' WITH 68 COMMITMENTS. WHEN I SUBMITTED FOR APPROVAL, 10/24/95 I INCLUDED [redacted]; HOWEVER, BECAUSE OF THE CHANGE OF STATUS ON THE PENDING SALES OF SEVERAL HOUSES AND THE NUMBER OF PEOPLE WHO HAD TO REPLACE THEIR HEATING & WATER HEATING OUT OF NECESSITY, I LOST SEVERAL PROSPECTS ON [redacted] AND [redacted] ANE, AS WELL. THESE WILL CONVERT (PROBABLY WITHIN THE NEXT YEAR).

SENT LARRY W BROWN 2/1/96 08:25

PLEASE GET WORK ORDERS SIGNED AND I WILL APPROVE THIS AFE. YOUR DIATE ATTENTION TO THIS WILL BE APPRECIATED.

SENT ROY D PEARSON 1/30/96 13:35

LARRY, I FEEL THIS IS A WORTHWHILE PROJECT AND APPRECIATE JUDY'S EFFORTS IN TRYING TO GET THIS EXTENSION UNDER WAY. HOWEVER, MORE INFORMATION IS NEEDED BEFORE I CAN RECOMMEND APPROVAL. COULD WE GET A FIELD WORK ORDER SIGNED FROM EACH POTENTIAL CUSTOMER SO WE CAN INSTALL A YARD LINE AT THE SAME TIME WE ARE INSTALLING THE MAIN?

SENT JUDITH G HAYNES 12/7/95 12:05

THESE RESIDENTS HAVE WANTED NATURAL GAS FOR SEVERAL YEARS AND A GREAT MAJORITY ARE HAVING PROBLEMS WITH THEIR HEATING AND/OR WATER HEATING. I CONSIDERED WORKING THIS IN SECTIONS; HOWEVER, 1/3 OF THE HOUSES_WERE IN THE FIRST 1800'. IN ORDER TO OBTAIN THE MOST CUSTOMERS I THOUGHT IT WISE TO WORK AS A WHOLE. ON SURVEYS I REQUEST THE CUSTOMER HAVE NATURAL GAS IN THEIR HOME WITHIN 90 DAYS OF THE MAIN EXTENSION COMPLETION. THIS WILL BE ON COUNTY RIGHT-OF-WAY.

SENT ROY D PEARSON 12/6/95 12:06

JUDY, I NEED THE SAME INFORMATION ON THIS EXTENSION THAT I REQUESTED ON THE SCOTTSVILLE ROAD APPROPRATION.

SENT DAVID H DOGGETTE 11/28/95 11:23

I CONCUR WITH THE REQUESTED EXTENSION OF OUR FACILITIES AND RECOMMEND APPROVAL.

SENT ROY D PEARSON 11/27/95 16:11

PLEASE REVIEW.

SENT JAY F CARNAHAN 11/27/95 12:17

RECOMMEND APPROVAL.

SENT GARY W MILLIGAN 11/17/95 17:02

OF TOTAL CUSTOMERS PLANNING TO CONVERT, 59 WILL BE EXPECTING REBATES FOR HEATING AND WATER HEATING CONVERSIONS TOTALING $9,950. SURVEY WAS COMPLETED IN AUGUST AND SEPTEMBER AND, THEREFORE, THEY WERE INFORMED OF 1995 REBATE AMOUNTS. THIS AMOUNT IS INCLUDED IN THE TOTAL COMMITMENT AMOUNT SUPPLIED EARLIER.

SENT JAY F CARNAHAN 11/17/95 07:24

PLEASE REVIEW JUDY'S COMMENTS AND PROVIDE QUANITY OF HOMES THAT ARE COMMITTED TO CONNECT WATER HEATING AND SPACE HEATING AND THE LEVEL OF INCENTIVE TO BE PAID.

SENT ROY D PEARSON 11/15/95 16:42

PLEASE REVIEW.

APPROVED LARRY W BROWN 11/14/95 16:23

RECOMMEND APPROVAL. MARKETING SURVEY SENT IN WITH TECHINICAL REVIEW INFORMATION.

SENT GENE R BAKER 11/14/95 11:32

TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.

SENT DOUGLAS E STEARNS 11/14/95 10:36

RECOMMEND APPROVAL. PIPE SIZE IS IN ACCORDANCE WITH THE LONG TERM DEVELOPMENT PLAN FOR THIS AREA WITH A 4" ON PEACHTREE TO OLD SCOTTSVILLE RD.

SENT LARRY W BROWN 10/31/95 16:45

PLEASE REVIEW.

APPROVED	JAMES E SLAUGHTER	10/27/95	14:09
APPROVED	WILLIAM B OOST	10/27/95	11:44

SEE DESCRIPTION

SENT	JUDITH G HAYNES	10/27/95	11:24

THERE ARE 104 ALL ELECTRIC AND LP CONVERSIONS ON [redacted]LAND, [redacted] AVE., [redacted]CT., AND [redacted] CT. THERE ARE 81 RESIDENTS WHO ARE READY TO CONVERT TO HTG, WH, GRILL, LIGHT, LOGS OR CS. THERE ARE APPROXIMATELY 13 LOTS THAT MAY BE BUILT ON IN THE FUTURE. MAIN EXTENSION IS POSSIBLE IN THE NEAR FUTURE.

SENT	WILLIAM B OOST	10/27/95	10:35

PLEASE REVIEW.

DISTRIBUTION: NELSON LBROWN OOST MILLIGAN FOGLE AKERS

INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT EARL FISCHER .
THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

Sent to:	OOST	- OOST, WILLIAM B.	(to)
	NELSON	- NELSON, HAROLD E.	(to)
	LBROWN	- BROWN, LARRY	(to)
	MILLIGAN	- MILLIGAN, GARY	(to)
	FOGLE	- FOGLE, CLYDE B.	(to)
	AKERS	- AKERS, KEVIN	(to)
	SLAUGHTE	- SLAUGHTER, JIM	(to)
	HAYNES	- HAYNES, JUDY	(to)
	PRICHARD	- Richardson, Pat	(to)
	PURCELL	- PURCELL, JACKIE	(to)
	KRAMER	- KRAMER, CONNIE M.	(to)

APPROPRIATION FOR EXPENDITURE ATTACHMENTS

TO: DAVE DOGGETTE | TECHNICAL SERVICES

FROM Byron Oost | DISTRICT Bowling Green

AFE NUMBER 209322-026 | DATE 10-31-95

TITLE 411- [redacted]. 4" & 2" Ext.

CONSTRUCTION PROJECT DESIGN OVERVIEW ✓

SKETCH ✓

EXTENSION AGREEMENT n/a

CHECK

AMOUNT

OTHER

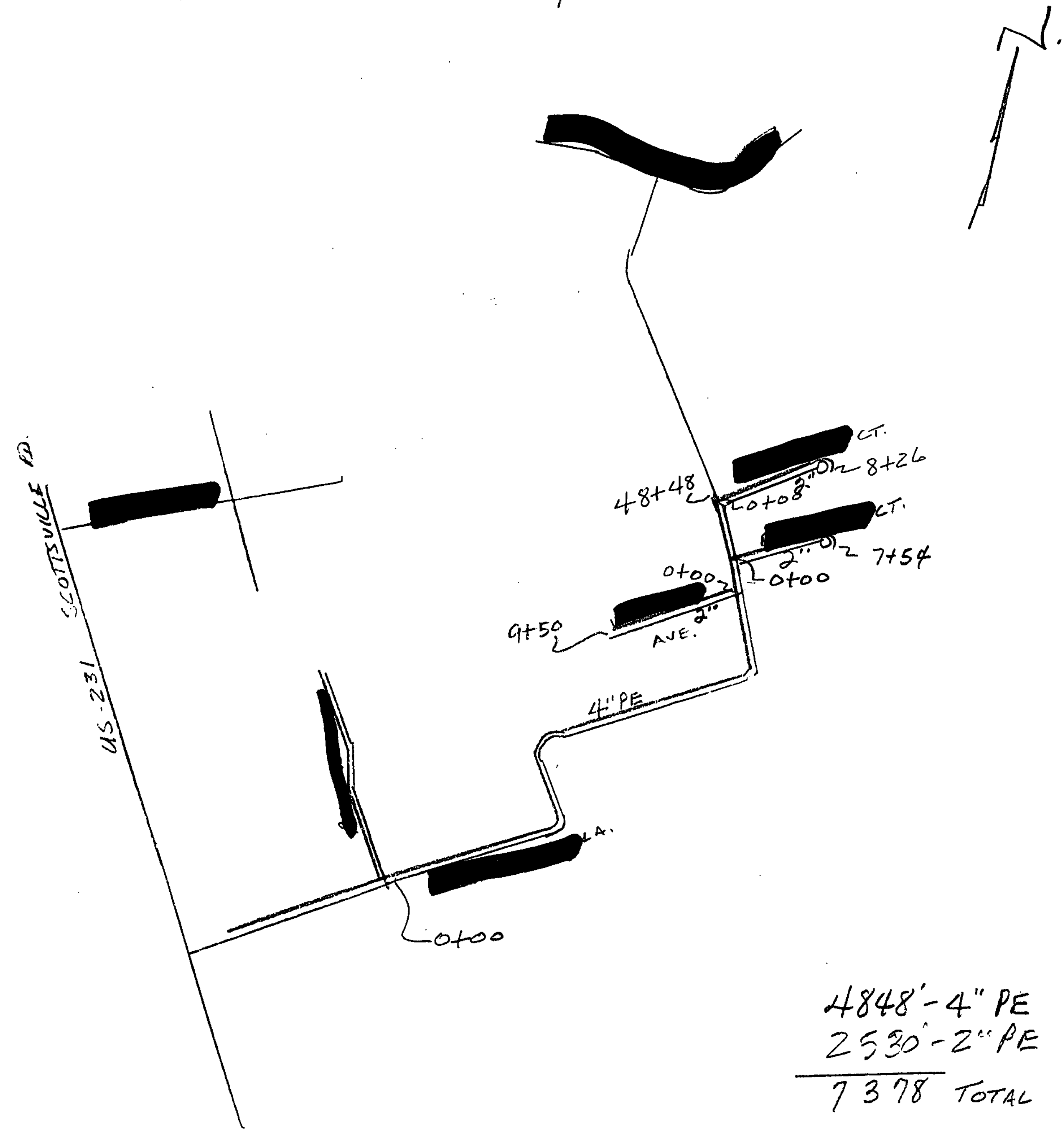
COMMENTS: Extension will serve 81 Conversion Customers that have been surveyed by Marketing Dept.

PLEASE NOTE AFE NUMBER ON ALL ATTACHMENTS

BY Slaughter DATE 10-26-95 SUBJECT [redacted] SHEET NO. 1 OF 1

CHKD. BY ______ DATE ______ 4" & 2" EXT. JOB NO. REQ

R/W ____ PUBLIC ☒ PRIVATE ☐ TOWN Bowling Green PLATE NO. 50.44-45



4848' - 4" PE
2530' - 2" PE
7378 TOTAL

Date 10-26-95 District B.GREEN Town Name B.GREEN

Project Name [redacted] LANE 4"&2" EXT.

Prepared By SLAUGHTER Job No. 96-15

Parameters:	Existing/ Retired	Proposed	Proposed Future
• M.A.O.P. (psig - oz)	60	60	
• System Winter Op. Press.	58	58	
• System Summer Op. Press.	35	35	
• Min. System Press. in Area of Extension	35	35	
• Load (MCFH)		12.1	
• Main Line Length (ft.)		7378	
• Main Line Diameter		2"&4"	
• Pipe Type		PE	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			
Major Gas Appliances/Load			

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. 560 Section No. 41L0
C. P. Class of Steel Main Retired Bare not C. P. ____ Bare C. P. ____ Coated C. P. ____

Comments 4" EXT. WILL SERVE 81 HOMES AND WILL PASS 23 MORE THAT MAY CONVERT AT A LATER DATE. 4" COULD POSSIBLY TIE-IN TO [redacted] RD LATER AND TIE BACK ON [redacted] RD TO TOWN SYSTEM

Approval Recommended:

Corrosion Technician: [signature]

[signature] 11-14-95

[signature] 11-14

Gene Baker

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

Rev: 3/15/93

204522-026

INTER-OFFICE CORRESPONDENCE

BOWLING GREEN
(Office)

Subject CONVERSIONS - [redacted]LANE
[redacted]VENUE
[redacted] COURT
[redacted]OURT

Date OCTOBER 24, 1995

To LARRY BROWN/JIM SLAUGHTER

THERE ARE 104 CUSTOMERS THAT I HAVE TALKED TO AND 81 OF THESE ARE INTERESTED IN GETTING GAS TO THEIR RESIDENCE FOR HEATING, WATER HEATING (or both), GRILL, OR LIGHT. THESE PEOPLE HAVE WANTED GAS FOR SEVERAL YEARS NOW; HOWEVER, THE MAIN WAS NOT CLOSE ENOUGH THAT WE WOULD HAVE ENOUGH CUSTOMERS TO RUN THE MAIN EXTENSION THAT WAS REQUIRED.

SCOTT ROGERS AT 430 [redacted]LANE HAS A GAS CENTRAL SYSTEM ALREADY INSTALLED BECAUSE HIS A/C WENT OUT IN LATE SUMMER (AUGUST, I BELIEVE). HE IS ONLY ABOUT 250' from where the main ends just past [redacted] ENTRANCE on the right side coming from [redacted] ROAD. If at all possible, could we get gas to this conversion customer (if not to the entire development at the present)?

The footage for this project was given to me as follows:

[redacted] TO FREESTONE	4,848'
[redacted]E	950'
[redacted]COURT	754'
[redacted]COURT	826'
TOTAL FOOTAGE	7,378'

RESPECTFULLY SUBMITTED,

JUDY HAYNES
MARKETING DEPARTMENT

yes - 81
others - 23

[redacted] LANE CONVERSIONS
ON LEFT SIDE FROM [redacted] ENTR.

			HTG	WH	OTHER	COMMENTS
387	[redacted]	782-0756				
405	[redacted]	781-7508	X	LATER		
425	[redacted]	843-9923		X		
439	[redacted]G.	781-1602		LATER	LOGS	
57	[redacted]		----	----	----	no listing house for sale could not find at home
475	[redacted]	796-8940	X	X		
93	[redacted]	781-7944				Could not find at home- N/A when called.
25	[redacted]	782-1590	X	X		
41	[redacted] JR.	842-4180	LATER	X		
509	[redacted]	782-5883				
59	[redacted]					no listing Left note to call me.
	[redacted] SR.	781-2549	---	---	-----	Intheir 70's - cannot affor
35	[redacted]	842-7847		LATER		Has new heat pump
~~65~~	~~[redacted] F. K.~~	~~842-2089~~				
579	[redacted]	842-2089		LATER	LOGS	
01	[redacted] & [redacted]	781-1809			DRYER GRILL	Both are on LP now.
21	[redacted]	842-2064	LATER		LOGS	Has electric wall heaters

[redacted] LANE CONVERSIONS

ON RIGHT SIDE FROM PEACHTREE DOWNS ENTR.

		HTG.	WH	OTHER	COMMENTS
398	[redacted] 843-9567		X		
430	[redacted] 781-5040 wk.-782-4803	X	LATER		already changed c central unit
454	[redacted] ~~--782-6243-~~ ~~(ADDRESS in phone book -- 1623 Ogden Ave.~~	X	X	cs	
480	[redacted] 843-4979 about 1 mile off road	**	**		will consider if he can hook on fı Scottsville Road
500	[redacted] (no listing) about 1 mile off road				Left note for heı to call me.
504	[redacted] 781-8730		X		
506	[redacted] 782-6709	X			
524	[redacted] 782-1653	X			
~~526~~	~~(not on list ?)~~				
542	[redacted] 781-3309		X		Just bought new heat pump
614	([redacted]) LISA MASSEY-Occup.	X	LATER		
660	[redacted] 781-5775 Barb-843-1246	X	X		
680	[redacted]. 8428081 & [redacted]				She works at wrec
700	[redacted] 781-0816	LATER		GRILL	HAS new WH
724	[redacted] 781-2377			LOGS	

209322-026

ON LEFT SIDE - [redacted] LANE
FROM 751 TO 1355

		HTG.	W	OTHER	COMMENT
751	[redacted] 781-6185, wk-781-2900	X			
769	[redacted] 781-8566	X			
787	[redacted] 781-2672	X	X		
815	[redacted] 842-2200		X		
853	[redacted] 842-2597		X		
873	[redacted] 843-1246	X	X		
893	[redacted] 842-0186		LATER		
913	[redacted] 843-2266 ([redacted] name from list at ct h. @ 1908 McTavish 782-3398)	X			
931	[redacted] 843-1857 work: ([redacted] - Owner(781-4144) 782-4830	X	LATER		
949	[redacted] 843-2354				
969	[redacted] 781-4767	X			
987	[redacted] (Address: 247 Walter Ave. 781-4198)			LATER	Will install lgt org:
1005	[redacted] ER) 781-0610 wk. 843-5663		X	LIGHT GRILL	
1065	[redacted]				no listing
1105	[redacted] 781-8584	X		GRILL	
1127	[redacted] 842-3590	X			
1145	[redacted] 782-9050	----	----	-----	NOT INTERESTED.
	ENTRANCE TO WALTERS AVE. TO LEFT (12)				
1201	[redacted] 842-2740		LATER		HAS NEW HEAT PUMP
1301	[redacted] 796-9351	X			
1315	[redacted] 782-0854				YES - need to know appliance
1355	[redacted] 781-1974				

204322-026

ON RIGHT SIDE - [redacted] LANE

FROM 786 to 1340-entrance to Freestone

		HTG.	WH	OTHER	COMMENTS
786	[redacted] 781-2512		X	LOGS	
306	[redacted] 782-9267		X	LOGS	
	(OWNERS: [redacted] 781-2672)				
344	[redacted] 781-5232				
366	[redacted] 843-8935	X			
384	[redacted] 843-1501	X			
	[redacted] 842-7993 *	X			
884	[redacted] 782-8130				
30	[redacted] 843-1761	----	----	----	NOT INTERESTED-TRLR
52	[redacted] 842-8238		LATER	LATER	Has new elec. syste
74	===[redacted]				
040	[redacted] 842-3850		X	LOGS	
048	[redacted] 842-9608	----	---	-----	NOT INTERESTED AT THIS TIME
1054	[redacted] & [redacted]	X	X		GOING TO BUILD
094	[redacted] 843-6631	X	X		on LP now
	(Address in phone bk- 3239 Spring Hollow)				
156	[redacted] 782-1715	X			on LP NOW
200	[redacted]		X		Probably will conve as time goes on
	[redacted]				
300	[redacted]. (new LP furnace) 842-6857	X		LOGS	
340	[redacted]Y 782-7370	X			
	[redacted]				

209322-026

		HTG.	WH	OTHER	COMMENTS
	[redacted] AVENUE OFF [redacted] LANE				
140	[redacted] (LOT)	----	----	----	ONLY LOT ON WALTERS AVE.
160	[redacted]	LATER	LATER	GRILL FIREPLACE INSERT	
180	[redacted]	X	X		
200	[redacted]	X	X		
220	[redacted]	X	LATER		
236	[redacted]		X		Undecided what else he wi install.
260	[redacted]		X		
282	[redacted]	X			
	*********************************				
155	[redacted]				Non-publ. # left note to please call me.
171	[redacted] 842-7387	X			
191	[redacted] 782-1754	X			Having problems with htg. system.
207	[redacted] 781-3588			LIGHT	
	[redacted]		X		Installed new htg. systen
247	[redacted] 781-4198		X	GRILL	Installed new htg. systen
265	[redacted]			LIGHT GRILL	
285	[redacted]	HTG.	LATER		
	********************************* *********************************				
	[redacted] OFF [redacted]ANE				
150	[redacted]	X			HAS LP NOW
168	[redacted]			GRILL	
194	[redacted]	X	X		
206	[redacted] 842-4722	----	----	---	Definitely does not want : She was very rude!
	*********************************				
149	[redacted]				
169	[redacted]				
203	[redacted]			GRILL	
221	[redacted]	----	----	---	NOT JUST NOW - MAYBE LATEI
213	[redacted]	X			Nancy works for WRECC. HAS LP NOW
237	[redacted]	LATER		GRILL LOGS	

[redacted] OFF [redacted]

		HTG.	WH	OTHER	COMMENTS
130	[redacted]	LATER	LATER		GRILL
152	[redacted]	----	----	----	NO - THIS IS RENTAL PROPERT
174	[redacted]	X			
200	[redacted]		LATER	GRILL	
220	[redacted]		LATER	GRILL	
230	[redacted]		LATER	GRILL	
238	[redacted]			GRILL	
**********************************					
**********************************					
153	[redacted]	LATER	X		
193	[redacted]		LATER	GRILL	
205	[redacted]		X		
233	[redacted]			GRILL	
235	[redacted]	X			HAS LP NOW

04/29/96 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 02/16/96 AFE HAS RCVD FINAL APPRVL BY: ROBERT EARL FISCHER STATUS: A
FISCAL YEAR: 1996 TYPE: N

NUMBER: 209491-036 631 [redacted] AD EXTENSION
OP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 6110100 DANVILLE OFFICE (780)
PROP LOC: 631 HARRODSBURG
LINE NO.: 9590-631 ADDRESS: HARRODSBURG

CONTRACT: DEFERRED DEPOSIT
START DATE: 3/11/1996 COMPLETE DATE: 3/28/1996

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	916692	37602	10	380,000	321,773	31,123	27,104	73,988

4600'-4" & 2495'-2" PE MN [redacted]

4600' 4" PLASTIC PIPE AND 2495' 2" PLASTIC PIPE	7,998
STORES 25%	1,999
OTHER MATERIAL	430
STORES 25%	107
COMPANY LABOR	5,164
PAYROLL 22.71%	1,173
CONTRACTOR	20,685
TRANSPORTATION	360
ROCK REMOVAL	18,563
16.00 % NSOCCC	9,037
15.00 % A & G	8,472

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 73,988

DESCRIPTION:
THIS EXTENSION WILL SERVE 22 LOTS IN A NEWLY DEVELOPING SUBDIVISION AS WELL AS SEVERAL POTENTIAL CONVERSION CUSTOMERS THAT LIE ALONG THE 4450' EXTENSION REQUIRED TO REACH THE AREA. THE DEVELOPER WILL MAKE A DEPOSIT AND HAS ALSO SIGNED A DEFERRED AGREEMENT TO COVER THIS INSTALLATION OF 7,095'.
AN UPDATE OF 3/25/96 REFLECTS A REQUEST BY TECHNICAL SERVICE TO INCLUDE 4" PIPE INSTEAD OF 2" ON THE APPROACH TO THE AREA OF DEVELOPMENT.

MAP REFERENCE: PLATE 11 INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 92802 HARRODSBURG CTY & ISD

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT EARL FISCHER		
APPROVED	ROBERT EARL FISCHER	4/29/96	08:46
APPROVED	ROY D PEARSON	4/24/96	14:13
I RECOMMEND APPROVAL			
SENT	DAVID H DOGGETTE	4/24/96	10:14
I RECOMMEND APPROVAL OF THIS REQUEST.			
SENT	ROY D PEARSON	4/3/96	17:35
PLEASE REVIEW.			
APPROVED	DANNY R COLLIER	4/1/96	09:06

DEPOSIT WILL BE MADE 10 DAYS PRIOR TO CONST.

APPROVED DONALD L LANE 3/29/96 12:51

APPROVE.

PULLBACK DONALD L LANE 3/28/96 14:17

.

APPROVED DONALD L LANE 3/27/96 05:57

APPROVE.

APPROVED JOHN B GENTRY 3/26/96 15:12

PLEASE REVIEW FOR APPROVAL; HARD COPY BEING SENT TO YOU.

SENT GENE R BAKER 3/26/96 14:14

TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.

SENT DOUGLAS E STEARNS 3/26/96 13:49

RECOMMEND APPROVAL. PIPE SIZE IS APPROPRIATE FOR THE LONG-TERM GROWTH IN HARRODSBURG, PARTICULARLY IN THIS AREA NEAR THE NEW BYPASS AND TOWARD LEXINGTON.

SENT JOHN B GENTRY 3/25/96 08:15

PLEASE REVIEW THE CHANGES TO 4" YOU REQUESTED. IF SUITABLE, PLEASE RETURN TO ME TO START THE APPROVAL PROCESS.

SENT GENE R BAKER 3/7/96 14:08

SENT DOUGLAS E STEARNS 3/7/96 13:20

RECOMMEND REVISING THIS TO INSTALL 4600' OF 4" PE ALONG LEXINGTON RD DUE TO THE EXPECTED DEVELOPMENT IN THIS AREA. THE US 127 BYPASS IS UNDER CONSTRUCTION AND WILL PROMOTE ADDITIONAL DEVELOPMENT IN THIS AREA. THE REMAINING 2495' OF MAIN TO BE 2"PE IN THE SUBDIVISION OFF US 68 ([redacted]).

SENT JOHN B GENTRY 2/19/96 10:14

PLEASE REVIEW FOR TECHNICAL SERVICE. HARD COPY MATERIAL BEING SENT TO YOU.

SENT JANET G REED 2/16/96 10:18

18 YARD LINES HAVE BEEN SIGNED FOR CONVERSIONS ON [redacted]OAD BEFORE REACHING THE PROPOSED SUBDIVSION WITH A POSSIBILITY OF EIGHT MORE. THIS EXTENSION PASSES A FUTURE DEVELOPMENT ON THE [redacted] BEING BUILT AT THIS TIME.

SENT JOHN B GENTRY 2/16/96 10:02

PLEASE REVIEW AND RETURN TO ME WITH COMMENTS. HARD COPY MATERIAL IS AVAILABLE FOR REVIEW.

DISTRIBUTION: NELSON DCOLLIER GENTRY LANE KRAMER FOGLE

INSTRUCTIONS:

THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT EARL FISCHER .

THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

Sent to:	GENTRY	- GENTRY, JOHN	(to)
	NELSON	- NELSON, HAROLD E.	(to)
	DCOLLIER	- COLLIER, DANNY	(to)
	LANE	- LANE, DON	(to)
	KRAMER	- KRAMER, CONNIE M.	(to)
	FOGLE	- FOGLE, CLYDE B.	(to)
	MILLIGAN	- MILLIGAN, GARY	(to)
	PURCELL	- PURCELL, JACKIE	(to)
	REED	- REED, JANET	(to)

DAILY EXCAVATION, TRENCHING & SHORING SAFETY CHECKLIST/REPORT

		YES	NO
1.	HAVE UTILITY COMPANIES BEEN NOTIFIED OF PROPOSED EXCAVATION WORK (ONE-CALL SYSTEM)?	X	
2.	ARE ALL TOOLS, EQUIPMENT, AND SHORING MATERIALS READILY AVAILABLE PRIOR TO GOING TO THE JOB SITE?	X	
3.	ARE OVERHEAD UTILITY LINES NOTED AND PRECAUTIONS TAKEN TO AVOID CONTACT BY CRANES, BACKHOES, OR OTHER HEAVY EQUIP.?	X	
4.	IS HOUSEKEEPING AT JOB SITE ADEQUATE?	X	
5.	IS THE SPOIL PILE AT LEAST TWO FEET FROM THE EDGE OF THE EXCAVATION?		BiGGer
6.	IS THE EXCAVATION INSPECTED DAILY OR MORE FREQUENTLY WHEN THERE IS A CHANGE IN WEATHER OR ENVIRONMENT THAT COULD AFFECT THE SOIL?	X	
7.	ARE BARRICADES, STOP LOGS, IF NEEDED, PROPERLY PLACED?	X	
8.	ARE EXCAVATIONS FIVE (5) FEET OR DEEPER CORRECTLY SLOPED OR SHORED OR IS A TRENCH BOX (SHIELD) USED?	X	
9.	IS A LADDER OR OTHER MEANS OF EXIT (EGRESS) PROVIDED IN TRENCHES OR EXCAVATIONS FOUR (4) FEET OR DEEPER?	X	
10.	WHEN LADDERS ARE USED, DO THEY EXTEND THREE (3) FEET ABOVE THE SURFACE AND ARE THEY SECURED?	X	
11.	IS THERE EVIDENCE OF A POTENTIAL CAVE-IN SUCH AS DRY OR CRACKING SOIL?		X
12.	ARE SHORING AND SHIELDING SYSTEMS INSPECTED DAILY BY A COMPETENT PERSON?	X	
13.	IS SHORING REMOVED FROM THE BOTTOM UP WITH WORKERS OUTSIDE THE EXCAVATION?	X	
14.	IS THE TRENCH BACKFILLED AS SOON AS WORK IS COMPLETED?	X	
15.	IS THERE AN EXPOSURE TO TRAFFIC?		X
16.	ARE ALL UTILITIES IN WORK AREA LOCATED?	X	
17.	HAZARDOUS ATMOSPHERE?		X
18.	UNSTABLE CONDITION SURROUNDING EXCAVATION?		X
19.	IS SURFACE WATER PRESENT?		X
20	SHORING OR SLOPING REQUIRED		X

21. SOIL CLASSIFICATION (LIST) B

22. OXYGEN DEFICIENCY (LIST) NONE

LOCATION Hwy 68 & Main Ext. SIGNATURE [signature]

JOB NUMBER 0916692 DATE 9-11-96

PAGE 1 of 1

APPROPRIATION FOR EXPENDITURE ATTACHMENTS

TO: DAVE DOGGETTE — TECHNICAL SERVICES

FROM J. GENTRY — DISTRICT DANVILLE

AFE NUMBER 209491-036 — DATE 2-19-96

TITLE 631 [redacted]XTENSION

CONSTRUCTION PROJECT DESIGN OVERVIEW ✓

SKETCH ✓

EXTENSION AGREEMENT ✓

CHECK

AMOUNT $23,870

OTHER

COMMENTS: 4450'-4" ~~7095'~~ 2645' 2" PLASTIC PIPE PORTION OF DEPOSIT IS DEFERRED

PLEASE NOTE AFE NUMBER ON ALL ATTACHMENTS

Revised from original 4-8-96

APPROPRIATION FOR EXPENDITURE ATTACHMENTS

TO: DAVE DOGGETTE TECHNICAL SERVICES

FROM J. GENTRY DISTRICT DANVILLE

AFE NUMBER 209491-036 DATE 2-19-96

TITLE 631 [redacted] ROAD EXTENSION

CONSTRUCTION PROJECT DESIGN OVERVIEW ✓

SKETCH ✓

EXTENSION AGREEMENT ✓

CHECK

AMOUNT $23,870

OTHER

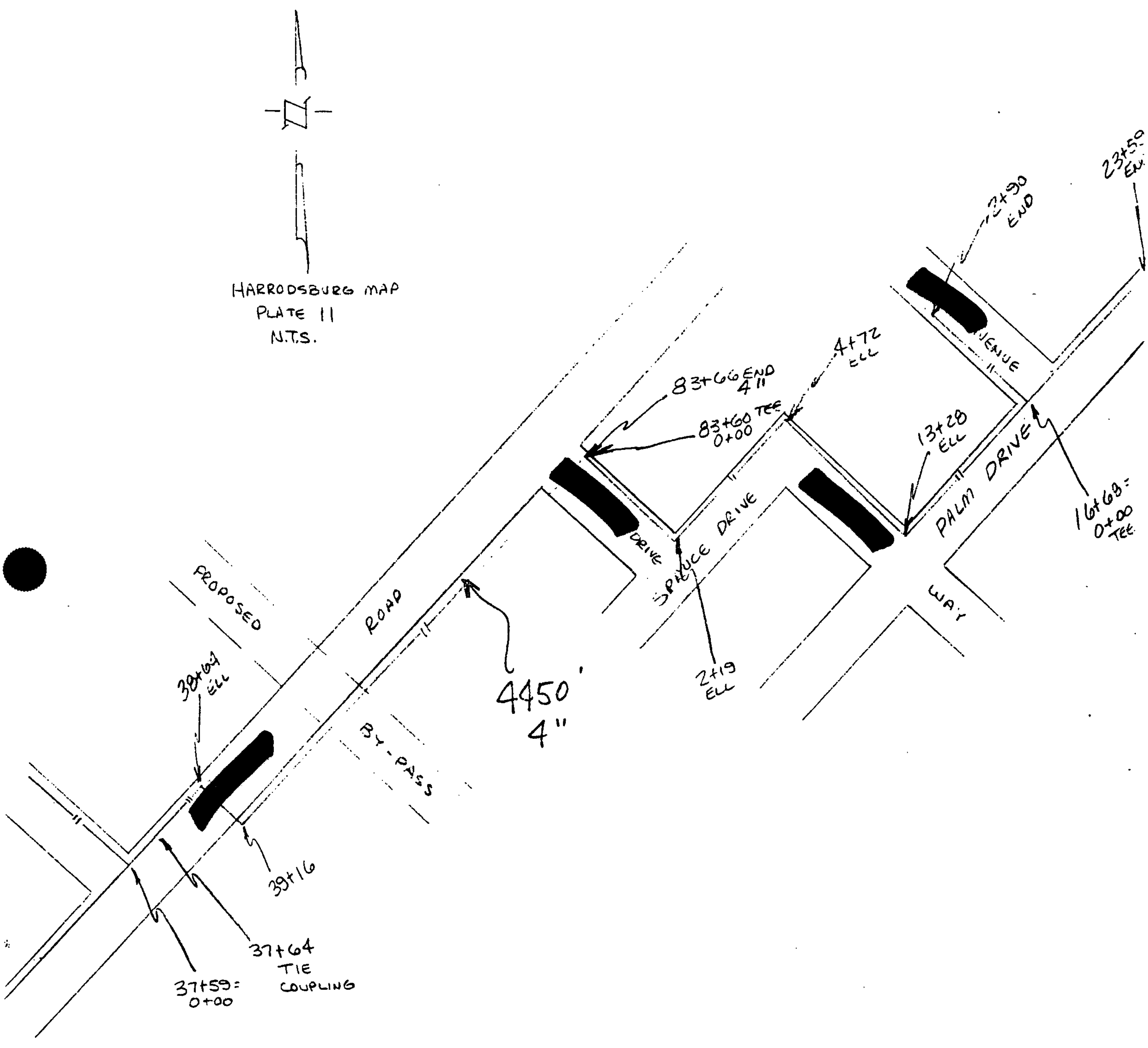
COMMENTS: 4" (4600' & 2495' 2" PLASTIC PIPE PORTION OF DEPOSIT IS DEFERRED

PLEASE NOTE AFE NUMBER ON ALL ATTACHMENTS

Post-It™ brand fax transmittal memo 7671 | # of pages ▸ 3

To DOUG STEARNS	From JOHN GENTRY
Co.	Co. 2-19-96
Dept.	Phone #
Fax #	Fax #

BY JBG. DATE 2-16-96 SUBJECT 631 [redacted] EXT. SHEET NO. 1 OF 1
CHKD. BY ______ DATE ______ JOB NO. 209491-036
R/W ____ PUBLIC ☐ PRIVATE ☑ TOWN HARRODSBURG PLATE NO. 11
PUE ₠



Revised from original 4-8-96

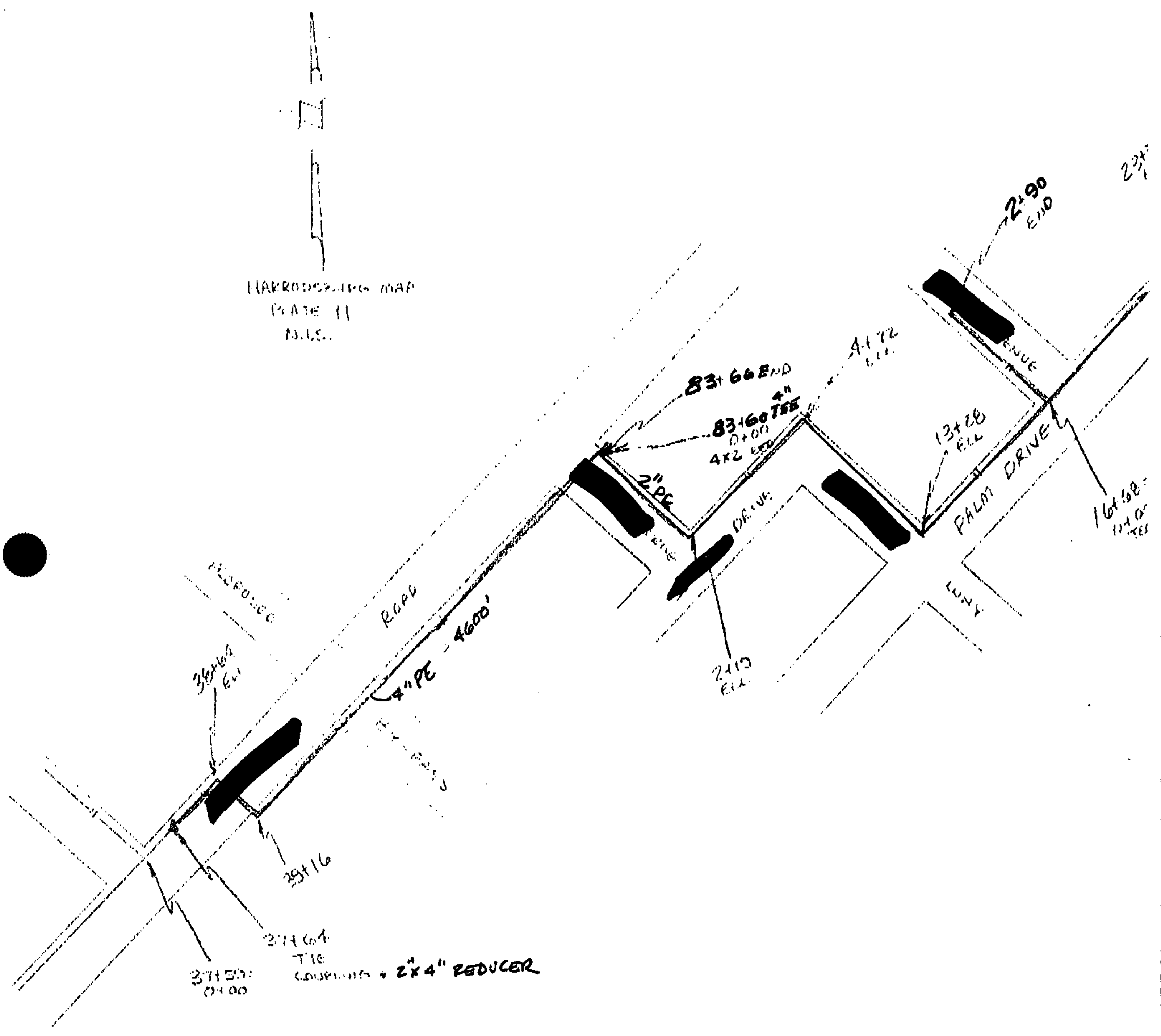
WK-730, R-3-88

BY JGG DATE 4-16-.. SUBJECT 631 [redacted] ROAD EXT. SHEET NO. 1 OF 1

CHKD. BY .... DATE .... JOB NO. 205M91-036

R/W...... PUBLIC ☐ PRIVATE ☑ TOWN HARRODSBURG PLATE NO. 11

POC 4



CONSTRUCTION PROJECT DESIGN OVERVIEW

Date 2-14-96 **District** Danville **Town Name** Harrodsburg

Project Name 631 [redacted]Road Extension

Prepared By J. Gentry **Job No.** 209491-036

Parameters:	Existing/ Retired	Proposed	Proposed Future
• M.A.O.P. (psig - oz)	55 =	60	
• System Winter Op. Press.	45	45	
• System Summer Op. Press.	35	35	
• Min. System Press. in Area of Extension	30		
• Load (MCFH)			
• Main Line Length (ft.)		4450' 4" 2645' 2"	
• Main Line Diameter	2"	2"	
• Pipe Type	P	P	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			
Major Gas Appliances/Load			

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. ___ Section No. _____ C. P. Class of Steel Main Retired Bare not C. P. _____ Bare C. P. _____ Coated C. P. _____

Comments This extension will serve 41 lots in [redacted] east of Harrodsburg and several potential conversions that lie along the 4450' of this extension required to reach and serve [redacted] The developer will make a deposit ten days prior to construction and has signed a deferred agreement.

Approval Recommended:

Corrosion Technician: ____________________

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

c:\123\data\desovr.wk1 Rev: 3/15/93

Revised from original 4-8-96

CONSTRUCTION PROJECT DESIGN OVERVIEW

Date 2-14-96   District Danville   Town Name Harrodsburg

Project Name 631 [redacted]xtension

Prepared By J. Gentry   Job No. 208491-036

Parameters:	Existing/ ~~Retired~~	Proposed	Proposed Future
* M.A.O.P. (psig - oz)	55	60	
* System Winter Op. Press.	45	45	
* System Summer Op. Press.	35	35	
* Min. System Press. in Area of Extension	30		
* Load (MCFH)			
* Main Line Length (ft.)		2,495-2" 7095 (4680)	
* Main Line Diameter	2"	2",4"	
* Pipe Type	P	P	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			
Major Gas Appliances/Load			

Any extension, retirement, relocation or replacement involving steel pipe (TWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. ___ Section No. _____ C. P. Class of Steel Main Retired   Bare not C. P. ______ Bare C. P. ______ Coated C. P. ______

Comments This extension will serve 41 lots in [redacted] east of Harrodsburg and several potential conversions that lie along the 4450' of this extension required to reach and serve [redacted] The developer has made a deposit and also signed a deferred agreement. RECOMMEND 4" ON LEXINGTON RD. DBS

Approval Recommended:

Corrosion Technician: ______

[signature] 2-20-96

D E Stearns 3-26-6

[signature]

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/or Economic Analysis

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WK-814, R-11-89

DEFERRED PAYMENT – MAIN EXTENSION AND DEPOSIT AGREEMENT

C.O. Number ____________
Completion Date ____________
203491-036

THIS AGREEMENT, made and entered into this 12 day of FEBRUARY 19 96, by and between WESTERN KENTUCKY GAS COMPANY, [redacted]nsboro, Kentucky, hereinafter designated as the COMPANY, and [redacted] of HARRODSBURG, Kentucky, hereinafter designated as the DEVELOPER;

WITNESSETH:

WHEREAS the Company is a gas utility engaged in the distribution and sale of natural gas but does not have presently installed a gas main within the Developer's Proposed Real Estate Subdivision and the required investment for the necessary main and facilities would be an unprofitable investment; and

The Developer is developing said real estate subdivision, hereinafter referred to as 'subdivision', and desires to obtain gas service to serve each residential lot in the subdivision; and

The Developer recognizes that the requested gas main will necessitate a capital investment either on the part of the Developer by way of a refundable Main Extension Deposit and/or on the part of the Company; and

The Developer wishes the Company to make the capital investment required, or a substantial part thereof, for the requested gas main extension of adequate size and capacity, in lieu of, in whole or in part, the Main Extension Deposit: and

In evaluating Developer's request, the Company has determined that there will not be a sufficient number of customers to be served by said main extension to yield the Company a fair rate of return upon the capital investment required to make such extension, unless all houses or dwelling units in the subdivision to be served by the extension utilize, as a minimum, gas water heating and gas central comfort heating appliances, and

In order to obtain gas service in the subdivision, the Company and the Developer mutually agree to defer the Main Extension Deposit, or a substantial part thereof, for a period of three (3) years after completion of said main extension, so that gas service will be made available to each lot in the subdivision and the adjacent premises.

NOW, THEREFORE, in consideration of the promises, one to the other hereinafter contained, the Company and the Developer covenant and agree as follows, subject to the Rules and Regulations of the Company and those of the Public Service Commission of Kentucky:

(1) The Company will install approximately 7095 feet of 2 -inch and — -inch gas main at an estimated cost of $ 7.97 per foot, totaling $ 56547 .00 and consisting of:

A. — feet of — -inch and — -inch "approach main" extending from the presently existing main on ____________ to a point on or adjacent to Developer's subdivision in ____________ County, Kentucky, and

B. 7095 feet of 2 -inch and — -inch "distribution main" to serve each lot in the subdivision, or portion thereof, being described as located at: EXTENDING ON [redacted]

The "approach main" to the subdivision and the "distribution main" within the subdivision, hereinafter are both sometimes referred to as 'main'.

The Company shall commence and pursue to completion, the construction of this main within a reasonable period of time consistent with the orderly development of the subdivision. If the main extension is to be performed in phases at the option of the Company, the term 'completion of construction' shall mean that date, after which, the initial phase of the main extension is complete and ready for customers to be connected ('connected' hereinafter shall mean connected for permanent gas service on a main extended under terms of this Agreement).

(2) The Company will permit the deferred payment of a deposit, or a substantial part thereof, by the Developer for a period of three (3) years following the 'completion of construction' of said main extension, an amount in the sum of $ 56547 .00 representing the estimated cost for 7095 feet of main @ $ 7.97 per foot, based on a footage allowance of 100 feet of main per customer to serve 41 customers. This latter figure being the number of customers who may reasonably be expected to contract for permanent gas service on the "distribution main" extension within the subdivision over the succeeding three (3) year period, a number mutually agreed upon by the Company and the Developer.

If, at the end of the three year period, the number of customers connected is insufficient to justify the total of 7095 feet allowed, the Developer will be required to deposit with the Company an amount in the sum of $ 7.97 per foot of main times the number of feet deficient. This footage allowance will be made in accordance with those provisions of Paragraph (5) hereof, for only those residential and/or commercial customers connected on the "approach main" or, if connected on the "distribution main", those utilizing, as a minimum, gas water heating and gas central comfort heating appliances.

This deferred deposit, if necessary, will be due and payable to the Company within 30 days after the Developer has been notified by registered mail that there remains a deficiency in the required number of customers and/or the corresponding footage allowed therefor at the end of the three year period, bearing interest at the rate of twelve percent (12%) per annum from the date due. Upon receiving payment of the deferred deposit, the Company and the Developer will also enter into a Letter Agreement amending the refund provisions of Paragraph (5) of this Agreement; however, maintaining the original ten-year (10) term. However, if this main extension has been performed in phases, the Developer will not be required to deposit monies for those phases of the main extension not complete or under construction by the Company.

(3) In addition, the Company will also permit additional footage allowances for the following customers who have made application for permanent gas service:

A. — feet, based on an allowance of one hundred feet of main per customer for — customer(s), and

B. ——— – ——— feet, based on an allowance, for commercial customers only for one foot of main for each cubic foot per hour (chf) of rated input to a base load appliance(s) greater than 200 cfh, for ——— – ——— customer(s), but which shall not exceed 900 feet of main allowed per customer so qualifying.

It being understood and agreed that no interest shall be due or payable at any time on this deposit. Developer will also secure at his expense any necessary rights of way or permits, and same shall be procured in the name of the Company and on the Company's standard form where same applies.

(4) When the length of new main to serve the subdivision exceeds the total footage of 4100 feet allowed in Paragraphs (2) and (3A,B) above, the Developer will deposit with the Company herewith the sum of $ 23870 .00 representing its equitable share of the estimated cost of the remaining 2995 feet of main @ $ 7 .97 per foot for excess footage not covered by these allowances.

(5) The Company agrees to refund to the Developer for a period of ten (10) years after 'completion of construction' of said main the sum $ 797 .00 for each additional customer connected. Also, for each additional commercial customer connected who has in service a base load appliance(s) the rated input to which is greater than 200 cfh, the Company agrees to refund to the Subscriber the cost of one foot of main or the sum of $ 7 . 97 for each cubic foot per hour of rated input to such base load appliance(s) greater than 200 cfh; however, this refund shall not exceed the cost of 900 feet of main allowed per customer so qualifying.

No refund shall be made for:

A. Any residential and/or commercial customer(s) connected and included in the footage allowance(s) in Paragraphs (2) and (3) above, totaling ——— – ——— feet, for whom a deposit has not been made, or

B. Any customer connected within said subdivision on the "distribution main" who does not utilize, as a minimum, gas water heating and gas central comfort heating appliances, or

C. Any customer for whom the Company installs a lateral main or additional extension.

However, the Company shall have the right to make any additional extension or lateral it so desires, and provided further, that in no event shall the refunds to the Developer exceed the total amount deposited by it under the terms of this Agreement.

If an order limiting the sale of gas to residential and/or commercial customers be promulgated by the Public Service Commission of Kentucky then the above refund Paragraph shall be held in abeyance until the extension of residential and/or commercial service is again authorized by Public Service Commission order, and no refund will be made while the Limitation Order is in effect.

(6) For additional main extensions in the subdivision in the future the Company will allow customer connections in excess of those needed to satisfy the terms and conditions of any Subsequent "Deferred Payment - Main Extension and Deposit Agreement" to apply toward refund of any deposit outstanding from a particular Original Agreement, provided the option in Paragraph (10) hereof is exercised and the following conditions are satisfied:

A. The Developer of any such Subsequent Agreement and the Original Agreement are one and the same party (affiliates may be considered the same party for purposes of this provision), and

B. The additional main extension in said subdivision is directly connected to a main which was previously extended under terms of a previous Agreement by the same Developer, and

C. The term of the Original Agreement will not be extended, remaining at ten (10) years.

(7) The Developer agrees that full and complete title and ownership to the gas main constructed under this agreement shall be vested entirely in and with the Company, and the Developer shall have no further claim upon said main except as herein provided, it being agreed that the Company will utilize said main as a part of its gas distribution system and shall be responsible for the operation and maintenance of same at all times.

(8) The provisions of this Agreement shall be binding upon and inure to the benefit of the successors and assigns of the Company and the Developer.

(9) This Agreement may be modified, amended, rescinded, or terminated only by a writing signed by the Company and the Developer or their duly authorized agents.

(10) This Agreement is the (Original/~~Subsequent~~)* Agreement applying to said subdivision. If a Subsequent Agreement, the Original Agreement, Construction Order Number ——— – ———, was signed and dated ——— – ———, 19——.

*Strike the inappropriate provision, at the option of the Developer if there exists an Original Agreement.

(11) In the event the Company is required to file suit against the Developer to enforce any provision of this Agreement, the Developer agrees to reimburse the Company for its expenses incurred in connection with such suit, including court costs and reasonable attorney's fees.

(12) This Agreement shall not become effective or binding on either party until approved and accepted by an authorized officer of the Company at its General Office in Owensboro, Kentucky.

(13) This Agreement is applicable in the entire service area of the Company.

(14) This Agreement is as authorized by rule of the Public Service Commission of Kentucky under 807 KAR 5:022, Section 9, Paragraph 16. "Extension of Service".

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in duplicate the date and year first herein above written.

WESTERN KENTUCKY GAS COMPANY
a division of Atmos Energy Corporation

WITNESS .... By: ....
COMPANY

Fern E. Fass for OAKWOOD

WITNESS Janet Y Reed By: X [signature]
DEVELOPER

10/04/96 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 09/11/96 AFE HAS BEEN REVIEWED BY: BELINDA J BELL STATUS: S
FISCAL YEAR: 1997 TYPE: N

NUMBER: U04249-001 296-WESTERN KY. TRAINING SITE REV.
OP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 296 RURAL MUHLENBERG CO
LINE NO.: 9515-296 ADDRESS: MULHENB CO RURAL
HWY 181

CONTRACT: N/A
START DATE: 10/1/1996 COMPLETE DATE: 12/1/1996

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A		36701	10	0	0	83,924	83,924-	83,924
(GE.)W.K.TRAINING SITE RIVER QUE								
6,640' 4" E.W. .188 STEEL PIPE								20,717
STORES EXPENSE 25%								5,179
OTHER MATERIALS								4,730
STORES EXPENSE 25%								1,183
300' 2" .EW STEEL PIPE								1,056
STORES EXPENSE 25%								264
ENGINEERING AND INSPECTION								7,549
CONTRACT LABOR								23,296
CAPITALIZED INTEREST FOR 6 DAYS								118
16.00 % NSOCCC								10,236
15.00 % A & G								9,596
A		37602	10	0	0	84,697	84,697-	84,697
(GE)W.K.TRAINING SITE DIST. SYS.								
1000' 4" POLY PIPE								1,400
STORES EXPENSE 25%								350
3,620 2" .216 SDR11 2406 POLY PIPE								1,665
STORES EXPENSE 25%								416
OTHER MATERIALS								6,000
STORES EXPENSE 25%								1,500
ENGINEERING & INSPECTION								6,000
CONTRACT LABOR								47,164
CAPITALIZED INTEREST FOR 9 DAYS								209
16.00 % NSOCCC								10,319
15.00 % A & G								9,674
A		36701	10	0	0	232,263	232,263-	232,263
(GE)WKTRAINING SITE HWY 181								
16,360' 4" E.W. .188 STEEL PIPE								51,043
STORES EXPENSE 25%								12,761
OTHER MATERIALS								9,784
STORES EXPENSE 25%								2,446
ENGINEERING & INSPECTION								19,966
RIGHT OF WAY								14,340
CONTRACT LABOR								65,522
CAPITALIZED INTEREST FOR 30 DAYS								1,884
16.00 % NSOCCC								28,138
15.00 % A & G								26,379
A		38000	10	0	0	11,014	11,014-	11,014

(GE)WKTRAINING SITE SERVICES

	1,710 1" POLY PIPE					616
	STORES EXPENSE 25%					154
	OTHER MATERIALS					1,300
	STORES EXPENSE 25%					325
	ENGINEERING AND INSPECTION					1,555
	CONTRACT LABOR					4,446
	CAPITALIZED INTEREST FOR 5 DAYS					16
	16.00 % NSOCCC					1,343
	15.00 % A & G					1,259
A	37900 10	0	0	36,609	36,609-	36,609
	(GE)WKTRAINING SITE REG. STATION					
	REGULATORS AND STATION PIPING					16,344
	ENGINEERING AND INSPECTION					1,063
	CONTRACT LABOR					10,500
	CAPITALIZED INTEREST FOR 5 DAYS					51
	16.00 % NSOCCC					4,465
	15.00 % A & G					4,186

RED APPROVAL AMT: 448,507 NORMAL APPROVAL AMT: 0

DESCRIPTION:
THIS MAIN EXTENSION WILL PROVIDE GAS TO THE NEW WESTERN KY. TRAINING CENTER IN GREENVILLE ON HWY 181. IT IS PROPOSED TO INSTALL THE FOLLOWING; 23,000' 4" STEEL, 200' 2" STEEL, 1,000' 4" POLY, 3,620' 2" POLY, 1,710' OF 1" POLY AND REGULATOR STATION. THIS EXTENSION WILL START AT (HWY 181 BY-PASS LOOP LINE 118.1) A 2" BLIND PLATED FLANGED PLUG VALVE LOCATED AT THE REGULATOR STATION AND METER SET FOR MUHLENBERG NORTH HIGH SCHOOL AND RUNNING WITH HWY 181 TO SITE. THIS EXTENSION WILL MAKE GAS AVAILABLE TO APPROXIMATELY 70 HOMES. THE GAS LOAD FOR PHASE I IS 6,689,000 BTU, PHASE II 6,689,000, PHASE III 3,000,000, PHASE IV NOT KNOWN AT THIS TIME. THE CUSTOMER AGREEMENT CONTRACT IS BEING HANDLED BY OWENSBORO'S MARKETING DEPARTMENT. A MAP AND CONSTRUCTION DESIGN AND OVERVIEW HAS BEEN FORWARDED TO ENGINEERING.

MAP REFERENCE: CCITY LINE 118.1 INSIDE/OUTSIDE CITY LIMITS: I
TAX AUTHORITY: 92905 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	GENE R BAKER		
SENT	BELINDA J BELL	10/4/96	11:00
UPDATED FOR YOUR REVIEW.			
SENT	GENE R BAKER	9/19/96	15:53
PLEASE UPDATE.			
SENT	BELINDA J BELL	9/18/96	15:21
RECOMMEND APPROVAL. BASED ON A STONER FLOW STUDY WITH A SYSTEM LOAD OF 50 MCFH AND A LOW END PRESSURE OF 200 PSI, 4" STEEL MAIN WITH TRANSMISSION PRESSURE ON IT WILL SERVICE THE PRESSURE AND LOAD REQUIREMENTS. THE 2" LINE THAT THE 4" EXTENSION WILL TIE INTO WILL ALSO SERVICE THIS LOAD.			
SENT	ROGER L GARMS	9/12/96	13:59
FOR TECHNICAL REVIEW AND COMMENTS.			
APPROVED	DONALD E GRIFFITH	9/12/96	10:56
READY FOR TECHNICAL REVIEW			
SENT	EDDIE G HAZZARD	9/11/96	15:09

THE CUSTOMERS CONTRACT IS BEING HANDLED BY THE COMMERICAL MARKETING DEPARTEMENT IN OWENSBORO. THE CONSTRUCTION DESIGN AND OVERVIEW ALONG WITH A MAP HAS BEEN FORWARDED TO OWENSBORO'S ENGINEERING DEPARTMENT.

DISTRIBUTION: NELSON GARMS HAZZARD FOGLE KRAMER DGRIFFIT

INSTRUCTIONS:
THIS AFE HAS BEEN SENT TO YOU BY BELINDA J BELL FOR YOUR REVIEW AND/OR APPROVAL. SINCE YOU ARE NOT ON THE APPROVAL PATH, YOU CAN EITHER:

1) APPROVE AFE IF YOU HAVE DOLLAR LEVEL AUTHORITY, OR

2) SEND BACK TO BELINDA J BELL .

Sent to: BAKER - BAKER, GENE (to)

541-90190

Date 10-7-98 District MADISONVILLE Town TRA LINE #

Project Name W. KY. TRAINING SITE (KY NAT GUARD) HWY 181

Prepared By Jimmie Spark Job No. ____

Parameters:	Existing/ Retired	Proposed	Proposed Future
* M.A.O.P. (psig - oz)			
* System Winter Op. Press.			
* System Summer Op. Press.			
* Min. System Press. in Area of Extension			
* Load (MCFH)			
* Main Line Length (ft.)			
* Main Line Diameter			
* Pipe Type			
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			

Major Gas Appliances/Load

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. ___ Section No. ____
C. P. Class of Steel Main Retired Bare not C. P. ____ Bare C. P. ____ Coated C. P. ____

Comments NEW TRANSMISSION LINE (PPMS # 541 90190)
"ALREADY ON PPMS" FOOTAGE = 23,280' 4" SK PIPE + 2" SK
APP # 0917614 = PART #1
#0917612 = PART #2
#0917616 = 2" Reg STA

Approval Recommended:

Corrosion Technician: Jimmie Spark

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

c:\123\data\desovr.wk1 Rev: 3/15/93

Western Kentucky Gas Company

MEMORANDUM

WESTERN KENTUCKY GAS

WK-742, R-2-86

To: Gene Baker

From: Belinda Bell BB

Subject: National Guard Armory Flow Study

Date: September 17, 1996

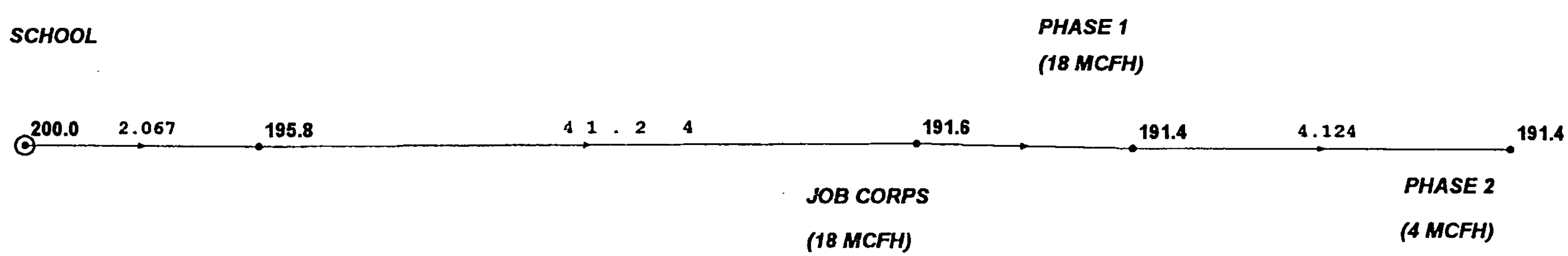
This flow study was run to determine the pipe size required to service both phase one and phase two of the Western Kentucky National Guard Armory Facilities near Greenville, Kentucky. The study was also run to determine whether or not the approximately 250' of 2" steel main that currently runs underneath the four lane 181 by-pass, will be adequate to carry the loads without a drastic drop in pressure.

WKG proposes to tie into the 2" steel transmission main near the Muhlenburg County High School and run approximately 22,000' of 4" steel transmission line to service the National Guard Armory.

Based on a transmission line pressure of 200 PSI (200 being the low end pressure) and a total system load of 50 MCFH, the 2" steel transmission line will be adequate to carry this load and pressure. A 4" steel transmission line will be of adequate size to service the requested loads. The transmission line pressure will be cut to distribution pressure via a station located at the Armory Facilities. With an inlet pressure of 200 PSI at the tie-in point, the second phase of construction near the River Queen Site will result in a pressure of 191 PSI.

Conclusions and Recommendations: The 2" steel transmission line along with 22,000' of 4" steel transmission line will service the estimated load of 50 MCFH to the National Guard Facilities based on a minimum inlet pressure at the 2" tie-in point of 200 PSI.

NATIONAL GUARD ARMORY
4" STEEL MAIN EXTENSION



ARMORY
SCHEMATIC
---RANGE---- COUNT
ALL ELEMENTS 4
NODE ANN:PRES
ELEM ANN:ID

State: BALANCED

Sep 12, 1996

Corners: (FEET)
UL:(-209,1035)
LL:(-209,269)
UR:(941,1035)
LR:(941,269)

WESTERN KENTUCKY TRAINING SITE
GREENVILLE, KENTUCKY
PROJECT SUMMARY

	Hwy 181	Cantonment Area	River Queen	Regulator Station	Project Total
Gross Cost	$232,263	$95,711	$83,924	$36,609	$448,507
Corp O/H	$26,595	$10,959	$9,610	$4,192	$51,356
WKG O/H	$28,368	$11,690	$10,250	$4,471	$54,779
Stores Cost	$15,207	$2,532	$6,362	$3,269	$27,370
Customer Cost *	$190,461	$82,220	$67,952	$29,148	$369,781

WESTERN KENTUCKY GAS COMPANY

Economic Analysis of Large Volume Customers — 10-Jun-96

Projected Income Statement and Cash Flow Analysis — 01:21 AM

DESCRIPTION: Western KY Training Site (Includes River Queen)

CAPITAL OUTLAY: (Incl. WKG O/H only)		Salvage Value @ End of Econ. Term		
Install Distr. System	$360,000	$0	Economic Term:	10 Yrs.
Supply Tap/Stations	0	0	Term Of Debt:	10 Yrs.
Receipt Station	0	0		
	0	0		
FERC Filings & Legal Fees	0	0		
Overhead for Engr/Magt.	0	0		
Sub-TOTAL	$360,000	$0		
Corp. OH & Stores (Not Incl)	$68,000	0		
Cash Deposit	0	0		
TOTAL	$360,000	$0		

FUNDED FROM:			
50.00%	Debt @	9.0%
50.00%	Equity @	33.9%

$0.0000 Per MCF is the margin necessary to pay out the capital outlay and meet the financial requirements of this project.

	Inflation Factor	Year 1	Year 2	Year 3	Year 4	Year 5
OPERATING REVENUES:						
Margin + WACOG x MCF/Yr. >>>		29,000	46,500	63,000	70,500	70,500
$0.0000 $0.0000 See Above	0.0%	$33,334	$53,644	$73,709	$82,486	$82,486
DEDUCTIONS FROM OPERATING REVENUES:						
COST OF GAS:						
WACOG x MCF/Yr.						
$0.0000 See Above	0.0%	0	0	0	0	0
LOST & UNACCOUNTED-FOR GAS:						
% Loss x WACOG x MCF/Yr.						
0.00% $0.0000 See Above	0.0%	0	0	0	0	0
Receipt Station Mntnce	0.0%	585	585	585	585	585
Distr. System Mntnce	0.0%	1,000	1,000	1,000	1,000	1,000
Odorization & Odorant	0.0%	180	216	250	265	265
	0.0%	0	0	0	0	0
Meter Maintenance	0.0%	500	500	500	500	500
....	0.0%		0	0	0	0
Total O & M Expenses		2,265	2,301	2,335	2,350	2,350
BOOK DEPRECIATION						
30 Year, Straight Line (3.33%)		12,000	12,000	12,000	12,000	12,000
Net Plant in Service		348,000	336,000	324,000	312,000	300,000
Accumulated Depreciation		12,000	24,000	36,000	48,000	60,000
TAXES-OTHER THAN INCOME						
Ad Valorem 0.0048 per $1 0.004	0.0%	1,759	1,759	1,759	1,759	1,759
DEBT INTEREST		16,200	14,580	12,960	11,340	9,720
TOTAL DEDUCTIONS		32,223	30,639	29,053	27,449	25,829
INCOME BEFORE TAXES ON INCOME		1,110	23,004	44,655	55,037	56,657
INCOME TAX CALCULATION						
Operating Income before Taxes		1,110	23,004	44,655	55,037	56,657
Plus: Book Depreciation		12,000	12,000	12,000	12,000	12,000
Less: Basis		360,000				
Times: Rate (20 Yr. Property)		3.750%	7.219%	6.677%	6.177%	5.713%
+-----Tax Depreciation		13,500	25,988	24,037	22,237	20,567
TAXABLE INCOME		(390)	9,016	32,618	44,800	48,090
Times: Combined Federal & State Rate		39.28%	39.28%	39.28%	39.28%	39.28%
TOTAL FIT & SIT LIABILITY		(153)	3,541	12,812	17,597	18,890
NET INCOME		$1,263	$19,463	$31,843	$37,440	$37,767
CASH FLOW ANALYSIS						
Operating Income Before Taxes		1,110	23,004	44,655	55,037	56,657
Plus: Book Depr'n		12,000	12,000	12,000	12,000	12,000
Less: Income Taxes		153	(3,541)	(12,812)	(17,597)	(18,890)
Less: Debt Principal Payment		(18,000)	(18,000)	(18,000)	(18,000)	(18,000)
Plus: Salvage Value		75,938	75,938	75,938	0	0
TOTAL CASH FLOW		$71,201	$89,401	$101,781	$31,440	$31,767
PRESENT VALUE OF CASH FLOW (@ ROE)		53,175	49,863	$42,396	$9,780	$7,380
PRESENT VALUE OF ACCUMULATED CASH FLOWS		$179,926				
PRESENT VALUE OF PROJECT EQUITY		180,000				
TOTAL NPV DIFFERENCE		($74)				

WESTERN KENTUCKY GAS COMPANY
KY. NATIONAL GUARD GREENVILLE
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 500 PSI Item	Qty.	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	0	Days	$	275.00	$	0
Acquisition Easement	0	Rods		5.00		0
Damages, Crops, Timber, Road, e	0	Rods		5.00		0
Permits, Filing & Recording Fees	0	Each		12.00		0
Railroad Crossing Permit	0	Each		100.00		0
				Total R-O-W	$	0
MATERIALS						
4" E.W. .188 STEEL	6,640	Lin. Ft.	$	3.12	$	20,717
8" Casing Pipe	0	Lin. Ft.		12.50		0
4 " Line Valves, ANSI 300 (720 WF	0	Each		873.00		0
4 " Weld Fittings	9	Each		18.50		167
Weld Insulator	0	Each		599.00		0
tracaewire	0	Each		0.05		0
4" Poly Fittings	0	Each		12.50		0
Joint Wrap – Tape	150	Roll		16.75		2,513
– Primer	2	Gallon		25.25		51
Anodes – 17 lb	7	Each		40.00		280
Cathodic Protection Test Station	7	Each		17.20		120
2" Blow-off Valves	0	each		500.00		0
2" Blow-off and Vent Piping	0	Lin. Ft.		4.50		0
Marker Post and/or Sign	6	Each		16.50		99
Misc. Materials & Expendables	1	Lump		1,500.00		1,500
					$	25,447
				25 % STORES	$	6,362
				Total Materials	$	31,809

WESTERN KENTUCKY GAS COMPANY
KY. NATIONAL GUARD GREENVILLE
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 500 PSI Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
Install Line Pipe	6,640	Lin. Ft.	$	3.20	$	21,248
Remove, Replace Blacktop & Concrete	0	Lin. Ft.		3.36		0
Pipe Fitting and Extra Labor for Valve Installations	0	Each		8.82		0
ROW Clearing	0	Lump		2,800.00		0
Rock Excavation	300	Cu. Yd.		3.36		1,008
Boring and tunneling	0	Each		8.88		0
Pressure Testing & De-watering, Sections	1	Lump		1,181.00		1,181
Install Cathodic Protection	7	Each		37.00		259
Extra Work	1	Lump		600.00		600
				Total Con. Labor	$	24,296
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	1	Lump	$	877.00	$	877
Field Inspection	44	Days		275.00		12,100
Pigging and Testing	2	Days		130.00		260
					$	13,237
				22.71 % Overhead	$	3,006
				Total Eng. & Insp.	$	16,243
				Project Sub-Total	$	72,348
				15% CORPORATE OVERHEAD		10,852
				16% WKG OVERHEAD	$	11,576
				GRAND TOTAL	$	83,924

WESTERN KENTUCKY GAS COMPANY
WK Traning Center Distribution System Piping Phase II
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 60 PSI Item	Qty.	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	0	Days	$	225.00	$	0
Acquisition Easement	0	Rods		5.00		0
Damages, Crops, Timber, Road, e	0	Rods		5.00		0
Permits, Filing & Recording Fees	0	Each		12.00		0
Railroad Crossing Permit	0	Each		100.00		0
				Total R-O-W	$	0
MATERIALS						
2".154 EW DRL JOINTS, FBE COATED	300	Lin. Ft.	$	3.52	$	1,056
4" POLY PIPE	1,000	Lin. Ft.		1.40		1,400
2" .216 SDR11 2406 POLY PIPE	3,620	Each		0.46		1,665
1" POLY PIPE	1,710	Lin. Ft.		0.36		616
4 " WELD FITTINGS	1	Each		18.50		19
PLASTIC FITTINGS	20	Each		22.77		455
4" POLY VALVE	1	Each		360.95		361
2" LINE VALVE ANSI 300 (720WP	1	Each		873.00		873
Joint Wrap - Tape	12	Roll		11.25		135
- Primer	1	Gallon		20.65		21
Anodes - 5 lb	3	Each		40.00		120
2" POLY VALVES	4	Each		85.31		341
2" Blow-off Valves	1	each		332.00		332
2" Blow-off and Vent Piping	0	Lin. Ft.		4.50		0
Marker Post and/or Sign	2	Each		16.50		33
MISC. MATERIALS & EXPENDABL	1	Lump		4,850.00		4,850
					$	12,277
				25 % STORES	$	3,069
				Total Materials	$	15,346

WESTERN KENTUCKY GAS COMPANY
WK TRAINING CENTER PHASE II
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 500 PSI Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
INSTALL LINE PIPE 2" STEEL	300	Lin. Ft.	$	3.20	$	960
INSTALL LINE PIPE 4" POLY	760	Lin. Ft.		3.30		2,508
INSTALL LINE PIPE 2" POLY	3,520	Lin. Ft.		2.40		8,448
INSTALL LINE PIPE 1" POLY	1,710	Lin. Ft.		2.60		4,446
PIPE FITTING & EXTRA LABOR FOR VALVE INSTALLATIONS	18	Lump		1,500.00		27,000
ROCK EXCAVATION	50	Cu. Yd.		95.00		4,750
BORING & TUNNELING	60	Feet		5.60		336
PRESSURE TESTING & DE-WATERING SECTION	1	Lump		1,800.00		1,800
Install Cathodic Protection	0	Each		47.25		0
Extra Work	1	Lump		1,362.00		1,362
				Total Con. Labor	$	51,610
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	1	Lump	$	591.00	$	591
Field Inspection	15	Days		275.00		4,125
Pigging and Testing	2	Days		130.00		260
					$	4,976
				22.71 % Overhead	$	1,130
				Total Eng. & Insp.	$	6,106
				Project Sub-Total	$	73,062
				15% CORPORATE OVERHEAD		10,959
				16% CORPORATE OVERHEAD	$	11,690
				GRAND TOTAL	$	95,711

WESTERN KENTUCKY GAS COMPANY
KY. NATIONAL GUARD GREENVILLE
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 500 PSI Item	Qty.	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	20	Days	$	275.00	$	5,500
Acquisition Easement	1,000	Rods		5.00		5,000
Damages, Crops, Timber, Road, s	672	Rods		5.00		3,360
Permits, Filing & Recording Fees	40	Each		12.00		480
Railroad Crossing Permit	0	Each		100.00		0
				Total R-O-W	$	14,340

MATERIALS	Qty.	Units		Unit Cost		Extended Cost
4" E.W. .188 STEEL	16,360	Lin. Ft.	$	3.12	$	51,043
8" Casing Pipe	0	Lin. Ft.		12.50		0
4 " Line Valves, ANSI 300 (720 WF	1	Each		873.00		873
4 " Weld Fittings	9	Each		18.50		167
Weld Insulator	0	Each		599.00		0
tracaewire	0	Each		0.05		0
4" Poly Fittings	0	Each		12.50		0
Joint Wrap - Tape	334	Roll		16.75		5,595
- Primer	5	Gallon		25.25		126
Anodes - 17 lb	15	Each		40.00		600
Cathodic Protection Test Station	15	Each		17.20		258
2" Blow-off Valves	1	each		500.00		500
2" Blow-off and Vent Piping	0	Lin. Ft.		4.50		0
Marker Post and/or Sign	15	Each		16.50		248
Misc. Materials & Expendables	1	Lump		1,417.00		1,417
					$	60,827
				25 % STORES	$	15,207
				Total Materials	$	76,034

WESTERN KENTUCKY GAS COMPANY
KY. NATIONAL GUARD GREENVILLE
GAS PIPELINE ESTIMATE

PIPELINE FACILITIES DESIGNED FOR 500 PSI Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
Install Line Pipe	16,360	Lin. Ft.	$	3.20	$	52,352
Remove, Replace Blacktop & Concrete	0	Lin. Ft.		3.36		0
Pipe Fitting and Extra Labor for Valve Installations	9	Each		8.82		79
ROW Clearing	1	Lump		2,000.00		2,000
Rock Excavation	0	Cu. Yd.		3.36		0
Boring and tunneling	950	Each		8.88		8,436
Pressure Testing & De-watering, Sections	1	Lump		2,000.00		2,000
Install Cathodic Protection	16	Each		47.25		756
Extra Work	1	Lump		1,337.00		1,337
				Total Con. Labor	$	66,960
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	1	Lump	$	611.00	$	611
Field Inspection	56	Days		275.00		15,400
Pigging and Testing	2	Days		130.00		260
					$	16,271
				22.71 % Overhead	$	3,695
				Total Eng. & Insp.	$	19,966
				Project Sub-Total	$	177,300
				15% CORPORATE OVERHEAD		26,595
				16% WKG OVERHEAD	$	28,368
				GRAND TOTAL	$	232,263

WESTERN KENTUCKY GAS COMPANY
WK TRAINING CENTER PHASE II
GAS REGULATOR STATION ESTIMATE

DISTRIBUTION REGULATOR STATION Item	Qty.	Units		Unit Cost		Extended Cost
REGULATION SET MATERIALS						
4" Regulator, Fisher 627s	4	Each	$	1,100.00	$	4,400
1"x2" 500 PSI IMAC, Relief Valve	1	Each		1,400.00		1,400
'2" Valve 300 ANSI	6	Each		265.00		1,590
'2" Straner ANSI 300	1	Each		270.00		270
Misc. Pipe and Fittings	1	LUMP		3,415.00		3,415
FENCING	1	Lot		2,000.00		2,000
					$	13,075
				25% STORES	$	3,269
				Total Materials	$	16,344
CONTRACT LABOR						
Labor Welding	40	HOURS	$	113.40	$	4,536
Pipe Wrapping, C.C Forming	0	Lot		150.00		0
Pressure Test	1	Lump		2,464.00		2,464
Extra Work	1	Lump		3,500.00		3,500
				Total Con. Labor	$	10,500
ENGINEERING & INSPECTION						
Survey, Drafting, Mapping & Desi	1	Lump	$	170.00	$	170
Field Inspection	4	Days		182.00		728
					$	898
				22.71 % Overhead	$	204
				Total WKG Labor	$	1,102
				Sub-Total	$	27,946
				15% CORPORATE OVERHEAD		4,192
				16% WKG OVERHEAD	$	4,471
				GRAND TOTAL	$	36,609

03/20/97 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
NTRY: 09/11/96 AFE HAS RCVD FINAL APPRVL BY: ROBERT W BEST STATUS: A
ISCAL YEAR: 1997 TYPE: N

NUMBER: U04249-001 296-WESTERN KY. TRAINING SITE REV.
OP/SUB CO: 40 WESTERN KENTUCKY GAS
RATE/DIV: 9 WESTERN KENTUCKY GAS
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 296 RURAL MUHLENBERG CO
LINE NO.: 9515-296 ADDRESS: MULHENB CO RURAL
HWY 181

CONTRACT: N/A
START DATE: 10/1/1996 COMPLETE DATE: 12/1/1996

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	917612	36701	10	0	85,843	0	85,843-	85,843
	(GE.)W.K.TRAINING SITE RIVER QUE							
	6,640' 4" E.W. .188 STEEL PIPE							20,717
	STORES EXPENSE 25%				9019-001			5,179
	OTHER MATERIALS							4,730
	STORES EXPENSE 25%							1,183
	300' 2" .EW STEEL PIPE							1,056
	STORES EXPENSE 25%							264
	ENGINEERING AND INSPECTION							7,549
	CONTRACT LABOR							23,296
	CAPITALIZED INTEREST FOR 6 DAYS							118
	16.00 % NSOCCC							10,236
	18.00 % A & G							11,515
A	917613	37602	10	0	86,632	0	86,632-	86,632
	(GE)W.K.TRAINING SITE DIST. SYS.							
	1000' 4" POLY PIPE							1,400
	STORES EXPENSE 25%							350
	3,620 2" .216 SDR11 2406 POLY PIPE							1,665
	STORES EXPENSE 25%							416
	OTHER MATERIALS				OK			6,000
	STORES EXPENSE 25%							1,500
	ENGINEERING & INSPECTION							6,000
	CONTRACT LABOR							47,164
	CAPITALIZED INTEREST FOR 9 DAYS							209
	16.00 % NSOCCC							10,319
	18.00 % A & G							11,609
A	917614	36701	10	0	237,539	0	237,539-	237,539
	(GE)WKTRAINING SITE HWY 181							
	16,360' 4" E.W. .188 STEEL PIPE							51,043
	STORES EXPENSE 25%							12,761
	OTHER MATERIALS				9019-001			9,784
	STORES EXPENSE 25%							2,446
	ENGINEERING & INSPECTION							19,966
	RIGHT OF WAY							14,340
	CONTRACT LABOR							65,522
	CAPITALIZED INTEREST FOR 30 DAYS							1,884
	16.00 % NSOCCC							28,138
	18.00 % A & G							31,655

A	917615 38000 10	0	11,266	0	11,266-	11,266
	(GE)WKTRAINING SITE SERVICES					
	1,710 1" POLY PIPE					616
	STORES EXPENSE 25%					154
	OTHER MATERIALS					1,300
	STORES EXPENSE 25%		OK			325
	ENGINEERING AND INSPECTION					1,555
	CONTRACT LABOR					4,446
	CAPITALIZED INTEREST FOR 5 DAYS					16
	16.00 % NSOCCC					1,343
	18.00 % A & G					1,511
A	917616 37900 10	0	38,786	0	38,786-	38,786
	(GE)WKTRAINING SITE REG. STATION					
	REGULATORS AND STATION PIPING					16,344
	ENGINEERING AND INSPECTION					1,063
	CONTRACT LABOR					10,500
	CAPITALIZED INTEREST FOR 5 DAYS					51
	PRESSURE RECORDER & INSTALLATION					1,000
	16.00 % NSOCCC					4,625
	18.00 % A & G					5,203

RED APPROVAL AMT: 460,066 NORMAL APPROVAL AMT: 0

ESCRIPTION:
THIS MAIN EXTENSION WILL PROVIDE GAS TO THE NEW WESTERN KY. TRAINING CENTER IN GREENVILLE ON HWY 181. IT IS PROPOSED TO INSTALL THE FOLLOWING; 23,000' 4" STEEL, 200' 2" STEEL, 1,000' 4" POLY, 3,620' 2" POLY, 1,710' OF 1" POLY AND REGULATOR STATION. THIS EXTENSION WILL START AT (HWY 181 BY-PASS LOOP LINE 118.1) A 2" BLIND PLATED FLANGED PLUG VALVE LOCATED AT THE REGULATOR STATION AND METER SET FOR MUHLENBERG NORTH HIGH SCHOOL AND RUNNING WITH HWY 181 TO SITE. THIS EXTENSION WILL MAKE GAS AVAILABLE TO APPROXIMATELY 70 HOMES. THE GAS LOAD FOR PHASE I IS 6,689,000 BTU, PHASE II 6,689,000, PHASE III 3,000,000, PHASE IV NOT KNOWN AT THIS TIME. THE CUSTOMER AGREEMENT CONTRACT IS BEING HANDLED BY OWENSBORO'S MARKETING DEPARTMENT. A MAP AND CONSTRUCTION DESIGN AND OVERVIEW HAS BEEN FORWARDED TO ENGINEERING.

MAP REFERENCE: CCITY LINE 118.1 INSIDE/OUTSIDE CITY LIMITS: I
TAX AUTHORITY: 92905 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT W BEST		
APPROVED	ROBERT W BEST	3/20/97	14:14
APPROVED	JOHN CHARLES GOODMAN	3/20/97	13:54
	BOB, I CONCUR AND RECOMMEND APPROVAL. CHARLES.		
APPROVED	DAN L LINDSEY	3/4/97	10:34
	I RECOMMEND APPROVAL. PROJECT ECONOMIC AND DESIGN PACKET LOOK GOOD.		
SENT	LEWIS BINSWANGER	3/4/97	10:31
	RECOMMEND FOR APPROVAL BASED ON ECONIMICS AND DETAIL DESIGN AS PROVEDED BY WKG.		
SENT	DAN L LINDSEY	2/28/97	16:14
	PLEASE REVIEW AND MAKE RECOMMENDATION. IT HAS BEEN APPROXIMATELY 4 MO NTHS SINCE SPRINGER REVIEWED.		
APPROVED	ROBERT EARL FISCHER	2/25/97	16:08
SENT	JAY F CARNAHAN	2/24/97	11:53
	I CONCUR AND RECOMMEND APPROVAL. TRAINING SITE IS ANTICIPATING		

SERVICE ON MAY 1. CONTRACT LANGUAGE INCLUDING SECURITY OF PAYMENT BY CUSTOMER IS CURRENTLY BEING REVIEWED BY BOTH OUR INTERNAL AND CONTRACT

LEGAL LAWYERS.

SENT GARY W MILLIGAN 2/21/97 17:50

THE KENTUCKY NATIONAL GUARD HAS REVIEWED THE REVISED CONTRACT AND, WITH ONE MINOR REVISION REQUEST, SHOULD BE PREPARED TO SIGN IT. THE CONTRACT WILL THEN GO TO THE KPSC FOR APPROVAL, WHICH IS ANTICIPATEDTO BE COMPLETE WITHIN 30 DAYS. A COMPLETE LIST OF THE NAMES OF ALL HOME-OWNERS ALONG THE ROUTE OF THIS MAIN EXTENSION HAS BEEN PREPARED. ACTUAL CONTACT OF THESE RESIDNETS HAS BEEN POSTPONED AWAITING FINAL EXECUTION OF THIS CONTRACT.

SENT ROY D PEARSON 1/15/97 12:46

GARY,HAS THE CONTRACT BEEN EXECUTED BY THE NATIONAL GUARD? I UNDERSTAND THIS EXTENSION WILL ALSO MAKE GAS AVAILABLE TO APPROXIMATELY 70 HOMES HAS ANYONE CONTACTED THESE 70 POTENTIAL CUSTOMERS?

SENT JAY F CARNAHAN 11/5/96 15:22

RECOMMEND APPROVAL. THE CONTRACT HAS NOT BEEN EXECUTED BY THE NAIONAL GUARD, AT THIS TIME. ALSO, WE MAY NEED TO HAVE REGULATORY REVIEW PRIOR TO INSTALLATION OF FACILITIES.

SENT GARY W MILLIGAN 11/5/96 14:46

RECOMMEND APPROVAL. WITH THE NATIONAL GUARD'S PLANS TO BEGIN TRAINING EXERCISES IN MID-DECEMBER, WE SHOULD WORK TO EXPEDITE EXTENDING NATURAL GAS SERVICE TO THIS SITE. TIMING FOR THE INSTALLATION OF THIS MAIN WILL BE FAVORABLE FOR PICKING UP THE POTENTIAL RESIDENTIAL CONVERSIONS ALONG THE ROUTE WITH THE BEGINNING OF THE WINTER HEATING SEASON.

SENT JAY F CARNAHAN 11/5/96 11:34

PLEASE REVIEW AND PROVIDE COMMENTS.

SENT DAVID H DOGGETTE 11/5/96 08:57

I RECOMMEND APPROVAL. PLEASE REVIEW AND FORWARD TO PEARSON FOR FURTHER PROCESSING. IF YOU HAVE QUESTIONS OR WISH TO DISCUSS THIS, PLEASE ADVISE.

SENT 11/4/96 14:35

RECOMMEND APPROVAL BASED ON INFO. PROVIDED ECONOMICS LOOK GOOD. THE AVE. COST IS AROUND $15/FT. PACKET INCLUDING PRESSURE STUDIES, VICINIT Y SKETCH AND DETAILED ESTIMATES LOOK FINE.

SENT DAVID H DOGGETTE 10/29/96 09:20

FOR YOUR REVIEW AND COMMENT. THIS IS A PROJECT WHICH WE DISCUSSED ON A PHONE CONFERENCE EARLIER THIS YEAR. I HAVE SENT YOU A PACKET OF INFORMATION INCLUDING MAPS, SITE INFORMATION AND ECONOMICS. PLEASE ADVISE IF YOU NEED ANY FURTHER INFORMATION.

SENT JAMES L SMITH 10/24/96 16:11

RECOMMENDED FOR APPROVAL.

SENT DAVID H DOGGETTE 10/24/96 15:29

PLEASE REVIEW AND RETURN.

SENT JAMES L SMITH 10/24/96 11:06

A PRESSURE RECOREDR IS REQUIRED ON EACH REGULATOR STATION SERVING 10 OR MORE CUSTOMERS. NON-LOADED COST FOR A PRESSURE RECORDER INSTALLATION, $1000.00

RECOMMEND FOR APPROVAL.

SENT DAVID H DOGGETTE 10/24/96 10:50

FOR SUB-BUDGET REVIEW AND COMMENTS.

SENT ROY D PEARSON 10/16/96 11:16

DAVE, PLEASE REVIEW AND FORWARD_TO J.CARNAHAN.

APPROVED ROGER L GARMS 10/15/96 13:59

RECOMMEND APPROVAL.

SENT JAMES S ALLISON 10/15/96 10:10

I HAVE HEARD THAT THE NATIONAL GUARD PLANS TO BEGIN TRAINING SESSIONS

BY DECEMBER 15, 1996, AND THEY HAVE MADE REVISIONS TO THEIR PLANS (WHI
CH ORIGINALLY WAS PROPANE) TO USE NATURAL GAS CHANGING EQUIPMENT WHERE
NECESSARY. THIS PUTS US ON A SCHEDULE THAT MAY BE IMPOSSIBLE TO MEET
. ANYTHING WE CAN DO TO EXPEDITE THIS PROCESS WILL, I AM SURE, BE APP
RECIATED BY THE KY ARMY NAT'L GUARD. AS OF 10AM, TUESDAY. 10-15-96, I
HAVE NOT RECEIVED A SIGNED COPY OF THE CONTRACT WHICH WAS FEDEX DELIV
ERED TO THEM FOR RECEIPT 10-09-96. I WILL PROCESS AS SOON AS I RECEIV
E THE CONTRACT.

SENT ROGER L GARMS 10/4/96 16:29
PLEASE REVIEW AND COMMENT.
SENT GENE R BAKER 10/4/96 11:49
TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.
SENT BELINDA J BELL 10/4/96 11:00
UPDATED FOR YOUR REVIEW.
SENT GENE R BAKER 9/19/96 15:53
PLEASE UPDATE.
SENT BELINDA J BELL 9/18/96 15:21
RECOMMEND APPROVAL. BASED ON A STONER FLOW STUDY WITH A SYSTEM LOAD
OF 50 MCFH AND A LOW END PRESSURE OF 200 PSI, 4" STEEL MAIN WITH
TRANSMISSION PRESSURE ON IT WILL SERVICE THE PRESSURE AND LOAD
REQUIREMENTS. THE 2" LINE THAT THE 4" EXTENSION WILL TIE INTO WILL
ALSO SERVICE THIS LOAD.
SENT ROGER L GARMS 9/12/96 13:59
FOR TECHNICAL REVIEW AND COMMENTS.
APPROVED DONALD E GRIFFITH 9/12/96 10:56
READY FOR TECHNICAL REVIEW
ENT EDDIE G HAZZARD 9/11/96 15:09
THE CUSTOMERS CONTRACT IS BEING HANDLED BY THE COMMERICAL MARKETING
DEPARTEMENT IN OWENSBORO. THE CONSTRUCTION DESIGN AND OVERVIEW ALONG
WITH A MAP HAS BEEN FORWARDED TO OWENSBORO'S ENGINEERING DEPARTMENT.

DISTRIBUTION: NELSON GARMS HAZZARD FOGLE KRAMER DGRIFFIT

INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT W BEST .
THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

Sent to:	DGRIFFIT	- GRIFFITH, DON	(to)
	NELSON	- NELSON, HAROLD E.	(to)
	GARMS	- GARMS, ROGER L.	(to)
	HAZZARD	- HAZZARD, ED	(to)
	FOGLE	- FOGLE, CLYDE B.	(to)

WKG ECONOMIC ANALYSIS

PROJECT: WK Training Center LOCATION: Greenville

COST DATA			CUSTOMER DATA			
			RESIDENTIAL (# OF CUST.)	COMMERCIAL 1 (MCF/YR)	COMMERCIAL 2 (MCF/YR)	COMMERCIAL 3 (MCF/YR)
CAPITAL COSTS:						
CONSTRUCTION:	$448,507	1st YEAR LOAD:	10	1,000	27,000	0
SUPPLY TAP:	$0	2nd YEAR LOAD:	15	1,000	44,000	0
FERC FILING & LEGAL:	$0	3rd YEAR LOAD:	25	1,000	59,500	0
OTHER/Engr:	$0	4th YEAR LOAD:	45	1,000	65,000	0
TOTAL CAPITAL COST:	$448,507	5th YEAR LOAD:	45	1,000	65,000	0
		GAS REVENUE ($/mcf):	$1.77	$1.23	$1.14	$0.00
CONTRIB:	$199,000	GAS COST ($/mcf):	$0.00	$0.00	$0.00	$0.00
ADVANCE:	$0	M & R COST ($/cust):	$0	$0	$585	$0
		OTHER COST ($/cust):	$0	$0	$1,000	$0
		OPER. EXP ($/cust):	$0	$0	$680	$0
		LOAD/CUST. (mcf/yr.)	100			

ECONOMIC ANALYSIS	1ST YEAR	2ND YEAR	3RD YEAR	4TH YEAR	5TH YEAR
TOTAL THRUPUT (MCF)	29,000	46,500	63,000	70,500	70,500
TOTAL REVENUES	$33,780	$54,045	$73,485	$83,295	$83,295
TOTAL GAS COST	$0	$0	$0	$0	$0
NET INCOME	$18,142	$31,806	$43,630	$49,606	$49,625
NET PLANT IN SERVICE	$242,731	$234,648	$226,834	$219,280	$211,978
RATE OF RETURN	7.5%	10.5%	16.3%	20.9%	23.0%
THIS INVESTMENT WILL BE RECOVERED AFTER A PERIOD OF (YRS.MNTHS):				5.7	

DIVISION CONSTANTS				
UNACCOUNTED-FOR (%):	2.1		DEPRECIATION EXP (%):	3.33
AD VALOREM TAX (%):	0.0049		INCOME TAX (0.00):	0.3928
GROSS RECEIPTS TAX (%):	0		INTEREST EXPENSE (%):	9
DEBT TO EQUITY RATIO	0.5	(CURRENT ATMOS RATIO IS 0.5)		

WKG ECONOMIC ANALYSIS

PROJECT: WK Training Center **LOCATION:** Greenville

without overheads

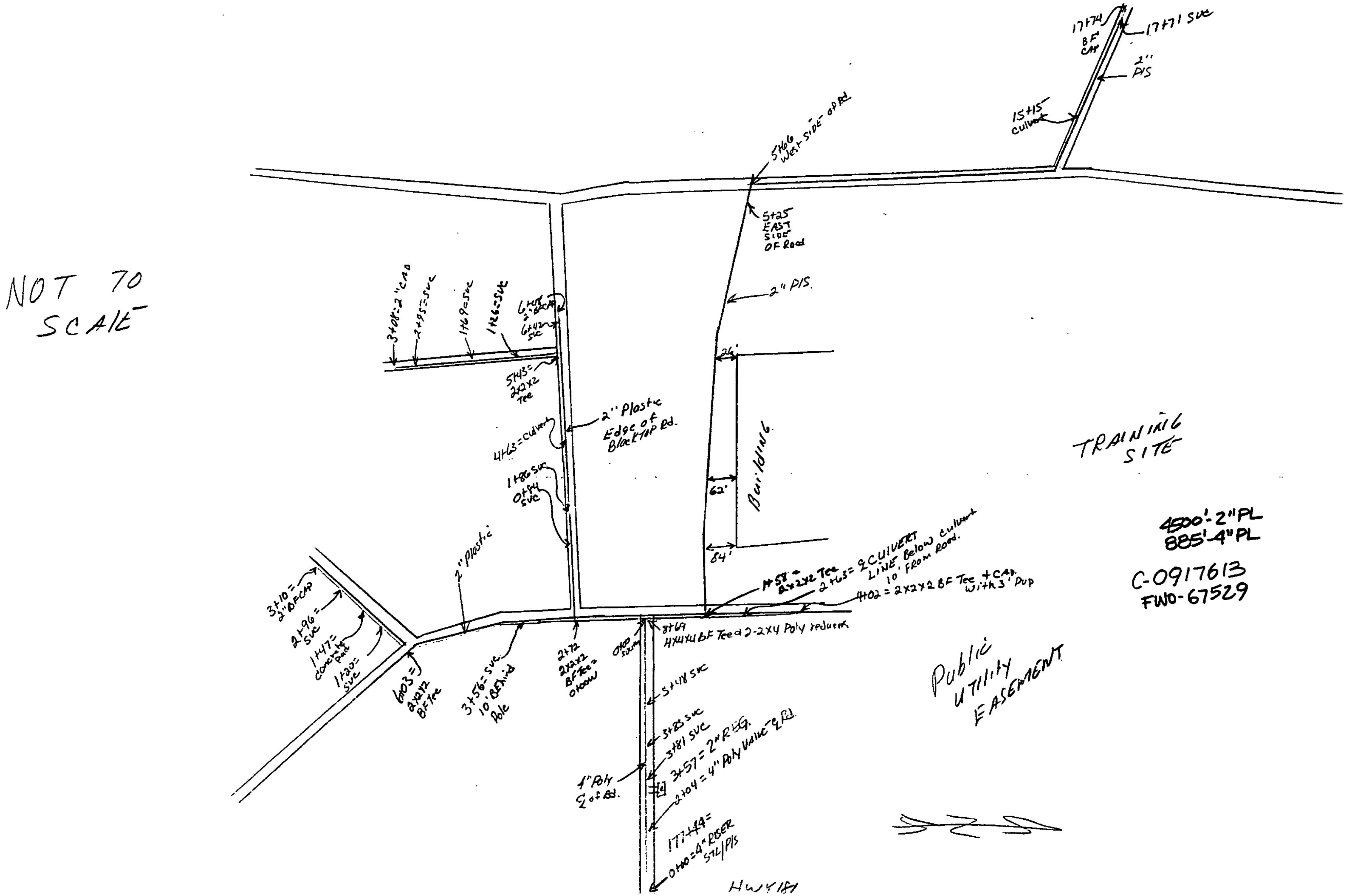
COST DATA		CUSTOMER DATA				
CAPITAL COSTS:			RESIDENTIAL (# OF CUST.)	COMMERCIAL 1 (MCF/YR)	COMMERCIAL 2 (MCF/YR)	COMMERCIAL 3 (MCF/YR)
CONSTRUCTION:	$360,000	1st YEAR LOAD:	10	1,000	27,000	0
SUPPLY TAP:	$0	2nd YEAR LOAD:	15	1,000	44,000	0
FERC FILING & LEGAL:	$0	3rd YEAR LOAD:	25	1,000	59,500	0
OTHER/Engr:	$0	4th YEAR LOAD:	45	1,000	65,000	0
TOTAL CAPITAL COST:	$360,000	5th YEAR LOAD:	45	1,000	65,000	0
		GAS REVENUE ($/mcf):	$1.77	$1.23	$1.14	$0.00
CONTRIB:	$199,000	GAS COST ($/mcf):	$0.00	$0.00	$0.00	$0.00
ADVANCE:	$0	M & R COST ($/cust):	$0	$0	$585	$0
		OTHER COST ($/cust):	$0	$0	$1,000	$0
		OPER. EXP ($/cust):	$0	$0	$680	$0
		LOAD/CUST. (mcf/yr.)	100			

ECONOMIC ANALYSIS

	1ST YEAR	2ND YEAR	3RD YEAR	4TH YEAR	5TH YEAR
TOTAL THRUPUT (MCF)	29,000	46,500	63,000	70,500	70,500
TOTAL REVENUES	$33,780	$54,045	$73,485	$83,295	$83,295
TOTAL GAS COST	$0	$0	$0	$0	$0
NET INCOME	$18,623	$32,017	$43,834	$49,803	$49,815
NET PLANT IN SERVICE	$157,171	$151,937	$146,878	$141,987	$137,258
RATE OF RETURN	11.8%	16.4%	25.4%	32.4%	35.7%
THIS INVESTMENT WILL BE RECOVERED AFTER A PERIOD OF (YRS.MNTHS):				4.1	

DIVISION CONSTANTS

UNACCOUNTED-FOR (%):	2.1	DEPRECIATION EXP (%):	3.33
AD VALOREM TAX (%):	0.0049	INCOME TAX (0.00):	0.3928
GROSS RECEIPTS TAX (%):	0	INTEREST EXPENSE (%):	9
DEBT TO EQUITY RATIO	0.5	(CURRENT ATMOS RATIO IS 0.5)	



NOT TO SCALE
3+08=2"CAP
2+95=SVC
1+69=SVC
1+26=SVC
5+43=2x2x2 Tee
4+63=culvert
1+86 SVC
0+84 SVC
2" Plastic Edge of Blacktop Rd.
2" plastic
3+10=2"BF CAP
2+96=SVC
1+47=Concrete Pad
1+20=SVC
6+03=2x2x2 BF Tee
3+56=SVC 10' BEhind Pole
2+72 2x2x2 BF Tee=0+00
5+25 EAST SIDE OF Road
5+66 West side of Rd
2" P/S
24'
62'
84'
Building
4+58=2x2x2 Tee
2+63=℄ CULVERT LINE Below culvert 10' FROM Road.
4+02=2x2x2 BF Tee + CAP With 3' Pup
8+69 4x4x4 BF Tee & 2-2x4 Poly reducers
5+18 SVC
3+83 SVC
3+81 SVC
3+57=2" REG.
3+04=4" Poly Valve ℄ Rd.
4" Poly ℄ of Rd.
17+44=
0+00=4" RISER STL/PIS
HWY 181
17+74 BF CAP
17+71 SVC
2" P/S
15+15 culvert
TRAINING SITE
Public Utility EASEMENT
4500'-2"PL
885'-4"PL
C-0917613
FWO-67529

10/10/96 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 09/02/96 AFE HAS RCVD FINAL APPRVL BY: ROBERT EARL FISCHER STATUS: A
FISCAL YEAR: 1997 TYPE: N

NUMBER: 214453-007 311 - MARSHALL RIDGE REVENUE EXT.
OP/SUB CO: 40 WESTERN KENTUCKY GAS COMPANY
RATE/DIV: 9 WKG
RESP CTR: 3110100 PADUCAH OFFICE (750)
PROP LOC: 311 PADUCAH
LINE NO.: 9550-311 ADDRESS: PADUCAH

CONTRACT: DEFERRED DEPOSIT
START DATE: 10/21/1996 COMPLETE DATE: 11/18/1996

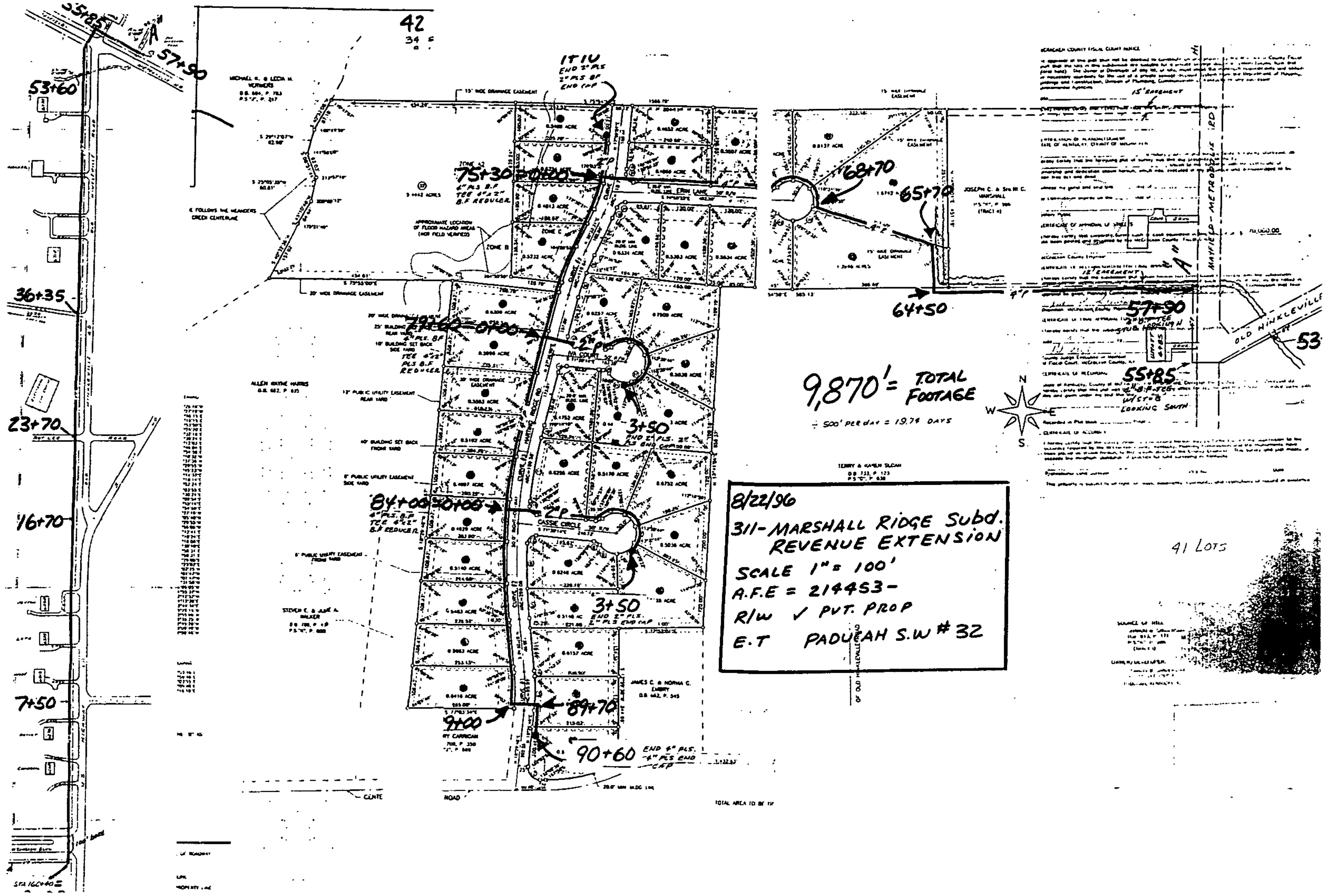
L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	916999	37602	10	400,000	98,245	80,548	221,207	73,521
311 - MARSHALL RIDGE REV. EXT.								
9,060' - 4" P.E PIPE								13,681
STORES EXPENSE								3,420
810' - 2" P.E PIPE								421
STORES EXPENSE								105
OTHER MATERIAL								1,736
STORES EXPENSE								434
SUPPLIES AND EXPENSE								676
COMPANY LABOR (INCL. 22.71%)								4,074
CONTRACT LABOR								31,376
TRANSPORTATION								200
16.00 % NSOCCC								8,980
15.00 % A & G								8,418

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 73,521

DESCRIPTION:
THIS EXTENSION WOULD MAKE GAS AVAILABLE TO FOURTY ONE LOTS IN THIS NEW RESIDENTIAL SUBDIVISION. WOULD ALSO MAKE GAS AVAILABLE TO TWENTY-FIVE EXISTING HOMES ALONG U.S HWY. 60 AND OLD HINKLEVILLE ROAD. MAIN EXTENSION WILL REQUIRE APP. 9,060' OF 4" PLS. AND 810' OF 2" PLS. MAIN (TOTAL 9,870'), COMING OFF OF EXISTING 4" PLS. MAIN ON MCCRACKEN BLVD. (INFORMATION AGE PARK). WE ARE "DEFERRING 4,100' (41 LOTS), DEVELOPER ([redacted]) AGREES TO UTILIZE NAT. GAS FOR BOTH HEAT AND HOT WATER IN EACH UNIT BUILT. A PARTIAL LINE DEPOSIT (5,770') IS REQUIRED. FUTURE EXTENSIONS ARE ALMOST CERTAIN, WE ARE ALREADY RECEIVING INQUIRIES.

MAP REFERENCE: PADUCAH S.W PLATE 32 INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 92401 PADUCAH CTY & ISD

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT EARL FISCHER		
APPROVED	ROBERT EARL FISCHER	10/10/96	13:19
APPROVED	ROY D PEARSON	10/10/96	08:13
	RECOMMEND APPROVAL.		
SENT	JAY F CARNAHAN	10/7/96	14:51
	RECOMMEND APPROVAL.		


8/22/96
311-MARSHALL RIDGE Subd.
REVENUE EXTENSION
SCALE 1" = 100'
A.F.E = 214453-
R/W ✓ PVT. PROP
E.T PADUCAH S.W # 32
9,870' = TOTAL FOOTAGE
÷ 500' PER DAY = 19.74 DAYS
41 LOTS
42
53+60
57+90
36+35
23+70
16+70
7+50
75+30
84+00
9+00
89+70
90+60
3+50
68+70
65+70
64+50
55+85
53
ERIN LANE
CASSIE CIRCLE
OLD HINKLEVILLE
MAYFIELD-METROPOLIS RD
N
S
E
W

SENT GARY W MILLIGAN 10/4/96 10:12

THE 5,770' OF APPROACH MAIN RUNNING ALONG HWY. 60 AND OLD HINKLEVILLE ROAD WILL RUN BY OVER 70 EXISTING HOMES, MANY OF WHICH ARE UTILIZING PROPANE PRESENTLY. THIS SECTION OF MAIN IS A REFUNDABLE MAIN, REQUIRING A DEPOSIT FROM THE DEVELOPER. THE TOTAL MAIN EXTENSION WILL MAKE NATURAL GAS AVAILABLE TO AT LEAST 3 OTHER NEW DEVELOPMENTS THAT HAVE EXPRESSED INTEREST IN NATURAL GAS. RECOMMEND APPROVAL.

SENT JAY F CARNAHAN 10/3/96 07:19

PLEASE REVIEW AND MAKE COMMENTS.

SENT ROY D PEARSON 10/2/96 09:04

SENT DAVID H DOGGETTE 10/1/96 13:46

I RECOMMEND APPROVAL OF THIS REQUESTED EXTENSION BASED ON THE MARKET OUTLOOK PROVIDE BY COMMENTS FROM THE DISTRICT.

SENT ROY D PEARSON 9/30/96 15:00

FOR YOUR REVIEW AND COMMENTS.

APPROVED WINSTON DARRELL MCKE 9/27/96 07:46

HEAVY GROWTH AREA. OPPORTUNITIES EXIST FOR CONVERSIONS AND NEW GROWTH. APPROVAL REQUESTED.

APPROVED DAVID E RUSSELL 9/26/96 15:19

TECHNICAL REVIEW COMPLETE. APPROVAL REQUESTED

SENT GENE R BAKER 9/26/96 08:35

TECHNICAL REVIEW IS COMPLETE, RECOMMEND APPROVAL.

SENT MICHAEL C SCHMIDT 9/26/96 08:26

RECOMMEND APPROVAL. AGREE WITH NECESSITY TO RUN 4" PE THRU SUBDIVISION AS THIS LINE WILL BE A MAIN FEED INTO THE DEVELOPING AREA. AGREE WITH TIE-IN, MATERIAL AND ALL FITTINGS SPECIFIED.

SENT DAVID E RUSSELL 9/4/96 15:54

IT SHOULD BE NOTED THAT THE CUSTOMER IS PAYING THE 4" PRICE UP TO THE SUBDIVISION, BUT IS BEING CHARGED FOR 2" INSIDE THE SUBDIVISION EVEN THOUGH WE ARE EXTENDING THROUGH THE SUBDIVISION WITH 4". FUTURE GROWTH IN THIS AREA IS WITHOUT QUESTION AND 4" WILL BE REQUIRED TO HANDLE FUTURE LOADS.

APPROVED EDWARD A TUCKER 9/4/96 14:01

FOR REVIEW/ COMMENTS, REQUIRES TECHNICAL REVIEW.

SENT TRUDY R WYATT 9/3/96 15:15

DEVELOPER, [redacted] HAS BEEN MOST SUCCESSFUL IN OTHER NEWLY DEVELOPED SUBDIVISIONS IN THE PAST TEN YEARS AND MORE AGH'S ARE NEEDED TO MEET THE DEMANDS OF HOMEBUYERS.
NATURAL GAS WAS REQUESTED TWO YEARS AGO_TO SERVE MANY L.P. CUSTOMERS WANTING TO CONVERT TO NATURAL GAS ALONG U.S. HWY. 60. THIS IS ONLY A BEGINNING TO THE OTHER KNOWN DEVELOPERS IN THE AREA WANTING GAS.
RECOMMEND APPROVAL. TRUDY WYATT

SENT EDWARD A TUCKER 9/2/96 11:59

FOR REVIEW/ COMMENTS PLEASE.

DISTRIBUTION: NELSON MCKENNEY RUSSELL ETUCKER FOGLE KRAMER

INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT EARL FISCHER .
THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

APPROPRIATION FOR EXPENDITURE ATTACHMENTS

TO: DAVE DOGGETTE　　　　TECHNICAL SERVICES

FROM DARRELL McKENNEY　DISTRICT PADUCAH

AFE NUMBER 214453-007　DATE SEPTEMBER 4, 1996

TITLE 311- MARSHALL RIDGE REV. EXT.

CONSTRUCTION PROJECT DESIGN OVERVIEW　YES

SKETCH　YES

EXTENSION AGREEMENT　YES *

CHECK　YES

AMOUNT　$ 30,613.00 *

OTHER * to be FORWARDED TO O'BORO AFTER TECH. REVIEW

COMMENTS: TOTAL JOB COST = $73,521

FOOTAGE = 9,870'　9,060 - 4"　810 - 2"

"S" to "WYATT" 9-2-96

"A" to "RUSSELL" 9-4-96

PLEASE NOTE AFE NUMBER ON ALL ATTACHMENTS

CONSTRUCTION PROJECT DESIGN OVERVIEW

Date 9/3/96 District PADUCAH Town Name PADUCAH

Project Name 311-MARSHALL RIDGE REV. EXT.

Prepared By EDDIE TUCKER Job No. 214453-007

Parameters:	Existing/ Retired	Proposed	Proposed Future
• M.A.O.P. (psig - oz)	60	60	
• System Winter Op. Press.	55	55	
• System Summer Op. Press.	25	25	
• Min. System Press. in Area of Extension			
• Load (MCFH)		16.5	
• Main Line Length (ft.)		9,060 ~~810~~	
• Main Line Diameter	4"	~~4"~~ 2"	
• Pipe Type	P.E	~~P.E~~ P.E	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			
Major Gas Appliances/Load			

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. 550 Section No. 31114
C. P. Class of Steel Main Retired Bare not C. P. _____ Bare C. P. _____ Coated C. P. _____

Comments THIS EXTENSION WOULD MAKE GAS AVAILABLE TO FOURTY ONE LOTS IN THIS NEW RESIDENTIAL SUB-DIVISION. WE ARE DEFERRING 4,100' TO DEVELOPER (SHARON SANDERSON) A PARTIAL DEPOSIT IS REQUIRED ON 5,770'. DEVELOPER AGREES TO UTILIZE NAT. GAS FOR BOTH HEAT AND HOT WATER IN EACH UNIT BUILT. FUTURE EXTENSIONS ARE ALMOST CERTAIN, HAVE ALREADY HAD INQUIRIES.

Approval Recommended:

Corrosion Technician: N.R

[signature] 9-12-96

[signature] 9-26-96

[signature]

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

c:\123\data\desovr.wk1 Rev: 3/15/93

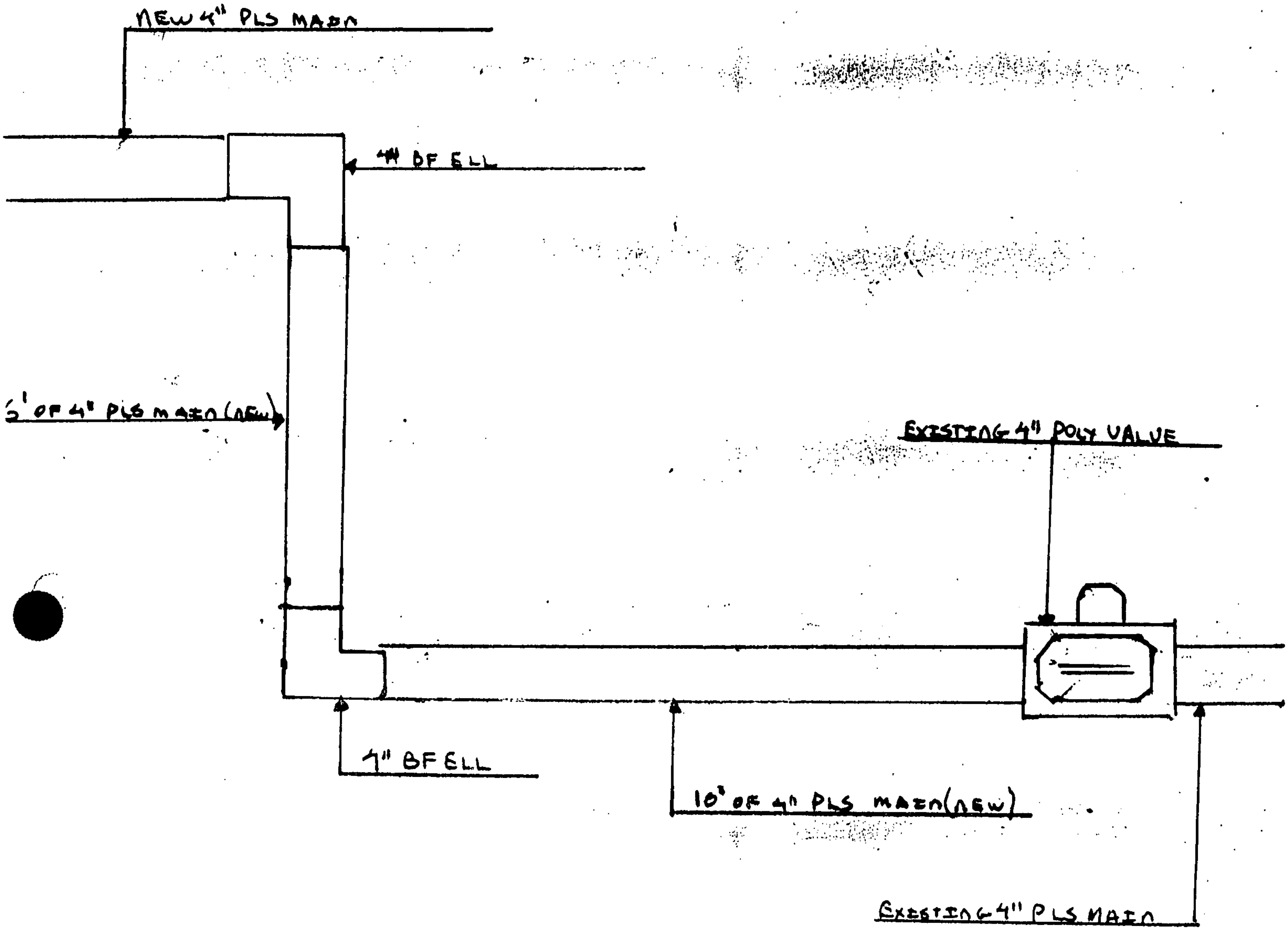
BY M.S. DATE 4/3/96 SUBJECT MARSHALL RIDGE REPAIR SHEET NO. 1 OF 2

CHKD. BY ______ DATE ______ Extension Tie-In JOB NO. 0916999

R/W ______ PUBLIC ☐ PRIVATE ☐ TOWN Parkway PLATE NO. ______

↑ NO PLATE NUMBER AVAILABLE ONE WILL HAVE TO BE CREATED

DETAIL OF TIE-IN



03/21/97 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
NTRY: 01/10/97 AFE HAS RCVD FINAL APPRVL BY: JOHN CHARLES GOODMAN STATUS: A
ISCAL YEAR: 1997 TYPE: N

NUMBER: 213698-044 411 - DRAKESBOROUGH SUB. 2" EXT.
OP/SUB CO: 40 WESTERN KENTUCKY GAS
RATE/DIV: 9 WESTERN KENTUCKY GAS
RESP CTR: 4110100 BOWLING GREEN OFFICE (760)
PROP LOC: 411 BOWLING GREEN
LINE NO.: 9560-411 ADDRESS: BOWLING GREEN

CONTRACT: DEPOSIT
START DATE: COMPLETE DATE:

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	917620	37602	10	675,000	378,543	19,924	276,533	96,912
15,094' OF 2" PE - DRAKESBOROUGH								
15,094' OF 2" .216 SDR-11 2406 PIPE								6,641
STORES EXPENSE 25%								1,660
OTHER MATERIAL								1,451
STORES EXPENSE 25%								363
SUPPLIES AND EXPENSES								2,000
TRANSPORTATION EXPENSE								100
COMPANY LABOR								800
CONTRACT LABOR								59,307
16.00 % NSOCCC								11,572
18.00 % A & G								13,018

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 96,912

DESCRIPTION:
EXTENSION WILL SERVE 64 CONVERSION CUSTOMERS IN DRAKESBOROUGH SUB. CURRENTLY, THERE ARE 64 SIGNED WORKORDERS AND 53 POTENTIAL FUTURE CONVERSIONS. 2" MAIN TO BE FED FROM 2" MAIN ON WINDMERE IN BARRINGTON SUBDIVISION. AGREEMENT WITH [redacted] LESS STORES AND CORP. EXPENSE, $5.42 PER FOOT. MAP WAS ALREADY SENT TO TECHNICAL SERVICES. CHECK($47,121) AND PAPERWORK EN-ROUTE TO TECHNICAL SERVICES.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 93601 BOWLING GREEN CTY & ISD

STATUS	NAME	DATE	TIME
CURRENT USER:	JOHN CHARLES GOODMAN		
APPROVED	JOHN CHARLES GOODMAN	3/21/97	11:05
APPROVED	DAN L LINDSEY	3/20/97	16:51
I RECOMMEND APPROVAL.			
ENT	LEWIS BINSWANGER	3/20/97	13:32
I CONCUR WITH THIS PROJECT. RECOMMEND FOR APPROVAL.			
SENT	DAN L LINDSEY	3/6/97	08:49
PLEASE REVIEW AND ADD COMMENTS AND RECOMMENDATION.			
APPROVED	ROBERT EARL FISCHER	3/4/97	15:05
APPROVED	JAY F CARNAHAN	3/1/97	10:04
I CONCUR AND RECOMMEND APPROVAL. THERE WAS AN INQUIREY TO THE KPSC BY			

INDIVIDUALS IN THIS SUBDIVISION CONCERNING OUR MAIN EXTENSION POLICY. PEOPLE IN THE SUBDIVISION WERE CONCERNED THAT THEIR NEIGHBORS COULD ELECT TO NOT CONTRIBUTE TO THE REQUIRED DEPOSIT AND CONNECT AFTER INSTALLATION OF THE DISTRIBUTION SYSTEM. THE KPSC AGREED WE WERE FOLLOWING OUR APPROVED PROGRAMS.

SENT GARY W MILLIGAN 2/28/97 13:29

RECOMMEND APPROVAL. RESIDENTS IN THIS SUBDIVISION HAVE EXPRESSED INTEREST IN NATURAL GAS SERVICE FOR SEVERAL YEARS. MANY HAVE BEEN HOLDING ON PROPANE IN ANTICIPATION OF WKG SERVICE AT A FUTURE DATE.

SENT JAY F CARNAHAN 2/26/97 17:42

PLEASE REVIEW AND PROVIDE COMMENTS.

APPROVED JOHN KEVIN AKERS 2/26/97 09:36

RECOMMEND APPROVAL OF THIS CONVERSION PROJECT. A NEW DEPOSIT AGREEMENT HAS BEEN PREPARED AND SIGNED BY THE [redacted]

SENT DAVID H DOGGETTE 2/12/97 11:41

I CONCUR WITH THIS REQUEST AND RECOMMEND APPROVAL.

SENT 2/12/97 08:04

RECOMMEND APPROVAL. PACKET AND DESIGN LOOK GOOD. CONTRACTS INCLUDED.

SENT DAVID H DOGGETTE 2/11/97 09:56

FRO YOUR REVIEW AND COMMENTS. A PACKET OF DOCUMENTATION HAS BEEN FORWARDED VIA MAIL.

SENT GENE R BAKER 2/5/97 07:16

RECOMMEND APPROVAL. COPY FOR P. SPRINGER IS ATTACHED TO YOUR HARD COPY.

SENT DOUGLAS E STEARNS 2/4/97 11:22

RECOMMEND APPROVAL. PIPE SIZE OK. A FLOW STUDY OF THE BOWLING GREEN SYSTEM WAS UPDATED TO INCLUDE THE ADDITIONAL LOAD EAST OF DRAKES CREEK AS WELL AS THE SYSTEM REINFORCEMENTS AND OTHER EXPANSIONS COMPLETED IN THE LAST TWO YEARS. THIS IS A GASWORKS FLOW MODEL. THE LOW PRESSURE AREA IS IN THE RIVER GREEN SUBDIVISION ON THE NORTH SIDE OF CEMETERY RD. AS THIS AREA DEVELOPS, ADDITIONAL SYSTEM REINFORCEMENTS ALONG I-65 AND/OR TO LOVERS LANE WILL BE NECESSARY.

SENT WILLIAM B OOST 1/14/97 11:23

PLEASE REVIEW.

SENT JUDITH G HAYNES 1/13/97 10:12

A MAIN EXTENSION OF 15,094' WILL BE RUN TO SERVE 64 CONVERSION CUSTOMERS IN DRAKESBOROUGH SUBDIVISION LOCATED TO THE RIGHT OF CEMETERY RD- AND PAST BARRINGTON MANOR. THE LINE WILL BE EXTENDED FROM BARRINGTON MANOR BY WAY OF WINDMERE. THIS WILL PASS 53 POSSIBLE CONVERSIONS FOR THE FUTURE; AS WELL AS, SEVERAL LOTS. THE 64 WORK ORDERS HAVE BEEN SIGNED AND A CHECK FOR $47,121.48 IS BEING GIVEN TO WKG FOR THE EXCESS FOOTAGE BY THE [redacted] ([redacted].

SENT WILLIAM B OOST 1/10/97 10:51

PLEASE COMMENT.

DISTRIBUTION: NELSON OOST MILLIGAN FOGLE AKERS SLAUGHTE

INSTRUCTIONS:

THIS AFE HAS RECEIVED FINAL APPROVAL BY JOHN CHARLES GOODMAN .

THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

APPROPRIATION FOR EXPENDITURE ATTACHMENTS

TO: DAVE DOGGETTE

TECHNICAL SERVICES

FROM Byron Cost

DISTRICT Bowling Green

AFE NUMBER 213698-044

DATE 1-10-97

TITLE 411- Drakesborough Sub. 2" Ext.

CONSTRUCTION PROJECT DESIGN OVERVIEW ✓

SKETCH ✓

EXTENSION AGREEMENT ✓

CHECK ✓

AMOUNT $47,121.00

OTHER

COMMENTS: Extension will serve 64 Conversion Customers and 53 potential future Conversions.

PLEASE NOTE AFE NUMBER ON ALL ATTACHMENTS

WKG 305 R-5-90

213698-044

COMPANY Western KY Gas Co.
TO:
TITLE:

APPROPRIATION REQUEST

FILE NUMBER

— GENERAL
TITLE OF PROJECT
SUBMITTED BY Drakesborough Sub. 2" Ext.
CONTRACT (S) Deposit LINE NO. 9560.411
CONFIRMING (Y/N) ___ LINE NAME
RATE DIV 09 LOCATION Bowling Green NO. ___
WORK TO BE: STARTED ___/___/___ COMPLETED ___/___/___

BUDGET CENTER BALANCE
DATE ___/___/___
BY

APPRO.-ACCOUNT NUMBER	ITEM STATUS	QUANTITY/DESCRIPTION	COST/CREDITS
37602	10	15,094' of 2" .216 SDR-11 2406 Pipe	6,641
		Stores Expense 25%	1,660
		Other Material	1,451
		Stores Expense 25%	363
		Supplies & Expenses	2,000
		Transportation Expense	100
		Company Labor	800
		Contact Labor	59,307
		Sub-Total	72,322
		WKG Overhead 16%	11,572
		Corp. Overhead 18%	13,018
		TOTAL	96,912

— COMMENTS
Extension will serve 64 Conversion Customers in Drakesborough Sub. Currently, there are 64 Signed Workorders and 53 potential future Conversions. 2" Main to be fed from Windmere in Barrington Sub. Deposit Agreement with Drakesborough Natural Gas Association. Technical Services already has mappings. Check $47,121 & Paperwork En-Route

BUDGET CONTROL NO.

PARISH/COUNTY ______ SCHOOL DISTRICT ______
RANGE ____ SECTION ____ WARD ____ TOWNSHIP ____ ICL/OCL ____

— OPERATING COMPANY — CORPORATE —
RECOMMENDED: DATE DATE
OPERATIONS ______ ___/___/___ ______ ___/___/___
TECH SERVICE ______ ___/___/___ ______ ___/___/___
MARKETING ______ ___/___/___ ______ ___/___/___
______ ___/___/___ ______ ___/___/___
______ ___/___/___ ______ ___/___/___
APPROVED
______ ___/___/___ ______ ___/___/___

COPIES:

PAGE ___ OF ___

X12070 044

CONSTRUCTION PROJECT DESIGN OVERVIEW

Date 1-10-97 District Bowling Green Town Name Bowling Green

Project Name 411 - Drakesborough Sub. 2" Ext.

Prepared By Byron Oost Job No. ____

Parameters:	Existing/ ~~Retired~~	Proposed	Proposed Future
• M.A.O.P. (psig - oz)	60	60	
• System Winter Op. Press.	55	55	
• System Summer Op. Press.	35	35	
• Min. System Press. in Area of Extension			
• Load (MCFH)			
• Main Line Length (ft.)		15,094	
• Main Line Diameter	2"	2"	
• Pipe Type	PE	PE	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			

Major Gas Appliances/Load

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. 560 Section No. 41105
C. P. Class of Steel Main Retired Bare not C. P. ____ Bare C. P. ____ Coated C. P. ____

Comments 2" PE main extention to be fed from 2" PE on Windmere in Barrington Sub.
Extension will serve 64 Conversion Customer with 53 potential future Conversions.

Approval Recommended:

Corrosion Technician: M. Jewell

Clyde B. Fogle 1-21-97

DE Stearns 2-4-97

Glen Baker

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

c:\123\data\desovr.wk1 Rev: 3/15/93

WK-804, R-11-89

MAIN EXTENSION AND DEPOSIT AGREEMENT

C.O. Number ____________
Completion Date ____________

THIS AGREEMENT, made and entered into this _____ day of ____________________, 19 ___, by and between WESTERN KENTUCKY GAS COMPANY, a division of Atmos Energy Corporation, of Owensboro, Kentucky, hereinafter designated as the COMPANY, AND [redacted] ____________________ of ____________, Kentucky, hereinafter designated as SUBSCRIBER:

WITNESSETH:

WHEREAS the Company is a gas utility engaged in the distribution and sale of natural gas but does not have presently installed a gas main adjacent to the Subscriber's Premises, and the required investment for the necessary main and facilities would be an unprofitable investment based on the number of customers and amount of revenues now available, and

The Subscriber desires to obtain gas service for use on its premises and is willing to make the investment required, or a substantial part thereof, for the requested gas main extension of adequate size and capacity so that gas service will be made available to the Subscriber's and adjacent premises.

NOW, THEREFORE, in consideration of the promises, one to the other hereinafter contained, the Company and the Subscriber covenant and agree as follows, subject to the Rules and Regulations of the Company and those of the Public Service Commission of Kentucky:

(1) The Company will install approximately 15,094 feet of 2 -inch and _____ -inch gas main at an estimated cost of $ 5.42 per foot, totaling $ 81,809.00, extending from the presently existing main in or on Windmere-Barrington Sub. to a point on or adjacent to Subscriber's premises in Warren County, Kentucky, and more particularly described as being located at: Drakesborough Sub.

(2) The Subscriber will deposit with the Company herewith the sum of $ 47,121.00 representing its equitable share of the estimated cost of 8694 feet of main @ $ 5.42 per foot, which includes a footage allowance(s) for the following customers who have made application for permanent gas service:

A. 6400 feet, based on an allowance of one hundred feet of main per customer for 64 customer(s), plus an additional

B. __________ feet, based on an allowance, for commercial customers only, of one foot of main for each cubic foot per hour (cfh) of rated input to a base load appliance(s) greater than 200 cfh for _______ customer(s), but which shall not exceed 900 feet of main allowed per customer so qualifying.

It being understood and agreed that no interest shall be due or payable at any time on this deposit. Subscriber will also secure at his expense any necessary rights of way or permits, and same shall be procured in the name of the Company and on the Company's Standard Form where same applies.

(3) The Subscriber agrees that full and complete title and ownership to the gas main constructed under this agreement shall be vested entirely in and with the Company, and the Subscriber shall have no further claim upon said main except as hereinafter provided, it being agreed that the Company will utilize said main as a part of its gas distribution system and shall be responsible for the operation and maintenance of same at all times.

(4) The Company agrees to refund to the Subscriber for a period of ten (10) years after 'completion of construction' of said main, the sum of $ 542.00 for each additional customer connected to said main for permanent gas service. Also, for each additional commercial customer connected to said main for permanent gas service who has in service a base load appliance(s) the rated input to which is greater than 200 cfh, the Company agrees to refund to the Subscriber the cost of one foot of main or the sum of $ 5.42 for each cubic foot per hour of rated input to such base load appliance(s) greater than 200 cfh; however, this refund shall not exceed the cost of 900 feet of main allowed per customer so qualifying. No refund shall be made for any residential and/or commercial customer(s) included in the footage allowance(s) in Paragraphs (2A) and (2B) above, totaling 6400 feet, for whom a deposit has not been made; or for any customer for whom the Company installs a lateral main or additional extension; however, the Company shall have the right to make any additional extension or lateral it so desires, and provided further, that in no event shall the refunds to Subscriber exceed the total amount deposited by him under the terms of this Agreement.

If an order limiting the sale of gas to residential and/or commercial customers be promulgated by the Public Service Commission of Kentucky then the above refund Paragraph shall be held in abeyance until the extension of residential and/or commercial service is again authorized by Public Service Commission order, and no refund will be made while the Limitation Order is in effect.

(5) This Agreement shall not become effective or binding on either party until approved and accepted by an authorized officer of the Company at its General Office in Owensboro, Kentucky.

(6) This Agreement is applicable in the entire service area of the Company.

(7) This Agreement is as authorized by rule of the Public Service Commission of Kentucky under 807 KAR 5:022, Section 9, Paragraph 16. "Extension of Service".

Addendum Attached

WESTERN KENTUCKY GAS COMPANY
a division of Atmos Energy Corporation

Witness .... By: ....
COMPANY

Witness *[signature]* By: *[signature]* 1/13/97 *[signature]* 1/13/97
SUBSCRIBER

Addendum to Agreement

8.) That rules and regulations attached shall be complied with to include recalculation of all refunds specifically under paragraph #28(b) based on total number of original and additional subscribers.

9.) The company agrees to complete installation of work authorized under this agreement within six (6) months of the signing of this agreement and that company shall refund any funds paid by subscriber for work not completed within six(6) months.

10.) That work included under this agreement <u>includes</u> service line installation from main line to customer(s) property line.

11.) That any modification to this agreement shall be in writing.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

27. Point of Delivery of Gas

The point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of the Company's service connection into the customer's service line or pipe or at the outlet of the meter, whichever is nearest the delivery main of the Company.

28. Distribution Main Extensions

a) The Company will extend without charge an existing distribution main one hundred (100) feet for each single customer provided the following criteria is met:

1) The existing main is of sufficient capacity to properly supply the additional customer(s);

2) Provided that the customer(s) contracts to use gas on a continuous basis for one (1) year or more; and

3) Provided the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

b) Whenever an extension exceeds one hundred (100) feet per customer, the Company will enter into an agreement with the customer(s) or subscriber(s). The agreement will provide for the extension on a cost per foot basis with the additional amount to be deposited with the Company by the customer(s) or subscriber(s). The agreement will contain provisions for a proportionate and equitable refund in the event other customers are connected to the extension within a ten (10) year period. Refunds shall be made only after the customer(s) has used gas service for a minimum continuous period of one (1) year. The Company reserves the right to determine the length of the extension, to specify the pipe size and location of the extension, and to construct the extension in accordance with its standard practices. Title to all extensions covered by agreements shall be and remain in the Company and in no case shall the amount of any refunds exceed the original deposit. Any further or lateral extension shall be treated as a new and separate extension.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: *Mary S. Lovell* Vice President – Rates & Regulatory Affairs

213698-044

73-73/839 No.

Date January 13, 1997

Pay to the order of Western Kentucky Gas Co. $ 47,121 00/xx

Forty seven thousand, one hundred twenty one & no/100 DOLLARS

TRANS FINANCIAL

[redacted]

Memo Deposit for Gas Main

⑆083900732⑆ 1001 792 8[redacted]

© DELUXE WALLET CM SAFE-CATE

ANTIQUE

Header Report: c:\gw50file[illegible]gdsbn

Base Pressure: 14.65 Psi
Base Temperature: 60 Fahrenheit
Specific Gravity: .585
Viscosity: .000007 Lbm/Ft-sec

Last Solved: At 16:24:17 On 02-03-1997
Largest Node Error: 0.090 Mcfh At Node MRB SHLBY
Design Factor: 1
Convergence Tolerance: .1 Mcfh
Maximum Iterations: 30
Upper Dampening Factor: 10
Lower Dampening Factor: .01
Compressibility Calculated: No

Condition Node:
Condition Pressure: 0 Psi
Minimum System Pressure: 0 Psi
Optimized By: Cost

Model Notes...

BGDSBN Bowling Green distribution system of mains 4" & larger except for specific important 2" & 3" mains that tie otherwise unconnected larger mains. Original study day was January 18, 1994, with updates to the system since 1/94.
Added are the subdivision south of the new Super Walmart, Target and Lowes shopping center north of Cave Mill Rd.
The tie on Smallhouse from Elrod to Three Springs is added to this study. The shopping center is tapped from the 6" on Campbell Lane.
Beltline feed at Elrod Rd to Smallhouse is included.
Drakes Creek area also included (River Green & Barrington)

Proposed extension to Drakesborough (64 customers with another 53 expected in the next year) is also included in this study.

Node Report: c:\gw50file\b[illegible]sbn

NODE NAME	PRESSURE	P KN	LOAD	ELEV	X COOR	Y COOR	
DSHM&IND	46.49	No	-5.000	545	0	0	
MODWLDG	45.30	No	-5.000	540	0	0	
MDWLD&31W	44.16	No	-5.000	565	0	0	
DSHM&PINR	44.10	No	-15.050	545	0	0	
CNTRY OV	40.79	No	-40.050	530	0	0	
TWIN FASTN	40.77	No	-5.000	530	0	0	
31W&SHPCTR	56.56	No	-10.000	520	0	0	
WRN CT HS	38.40	No	-15.000	500	0	0	
BNTR&EUC	29.30	No	-2.000	510	0	0	
BNTR&KNSG	28.07	No	-3.000	510	0	0	
KNSG&NWBRY	26.62	No	-3.000	520	0	0	
HMPT&BRVW	25.95	No	-5.000	530	0	0	
CM&CURTIS	50.39	No	-6.000	565	0	0	
CM&HARVEST	49.50	No	-0.700	560	0	0	
CM&NMILL	48.67	No	-1.000	565	0	0	
NM&CULDSAC	49.13	No	-1.000	565	0	0	
NM&PLEASNT	49.37	No	-1.000	565	0	0	
SHPG WTL	49.39	No	-17.000	565	0	0	
BRLY&HRVST	49.49	No	-1.300	565	0	0	
HRV&PLANTR	49.37	No	-0.800	565	0	0	
PLT&GRIDPD	49.19	No	-1.000	565	0	0	
NCM&GRP	49.18	No	-0.600	565	0	0	
CMBL&SHPGW	50.45	No	0.000	550	0	0	
EL&GR REG	60.00	Yes	106.613	550	0	0	
BARNG TAP	17.60	No	-0.100	550	0	0	
RIV GREEN	17.52	No	-1.500	550	0	0	
ECEM 4PEND	17.51	No	-0.500	550	0	0	
SCOTD 1E	17.44	No	-0.600	550	0	0	
BAR WIND	17.20	No	-0.250	550	0	0	
BAR SAX	16.78	No	0.600	550	0	0	
SAXWIND	16.85	No	-0.250	550	0	0	BARRINGTON
BAR WNDS	16.84	No	0.600	550	0	0	
WNDMR CT	16.83	No	-0.250	550	0	0	
SAX DRKB	15.57	No	-0.150	550	0	0	
DRK SENT	15.57	No	-0.100	550	0	0	
DRK SCTBR	12.40	No	-0.520	550	0	0	
WSCTBR DE	12.38	No	-0.300	550	0	0	
SCTC TONY	11.94	No	-0.300	550	0	0	DRAKESBORO
TONY DE	11.93	No	-0.300	550	0	0	
SCT MRKDL	11.33	No	-0.300	550	0	0	
SCT FSH	11.02	No	-0.300	550	0	0	
FSH MRNGST	10.91	No	-0.300	550	0	0	
FSH MRBRG	10.83	No	-0.300	550	0	0	
MRB SHLBY	10.77	No	-0.300	550	0	0	
W MRBRG	10.76	No	-0.200	550	0	0	
SHLBY SDE	10.76	No	-0.200	550	0	0	
E MRBRG DE	10.80	No	-0.250	500	0	0	
S FISH DE1	10.80	No	-0.250	500	0	0	
W MRNGST D	10.88	No	-0.200	500	0	0	

Node Report: c:\gw50file\b[illegible]sbn

NODE NAME	PRESSURE	P KN	LOAD	ELEV	X COOR	Y COOR	
W SCTBR DE	12.37	No	-0.200	500	0	0	DRAKESBORO
E SAXON DE	15.54	No	-0.200	500	0	0	
LKS RVGRN	8.89	No	-1.500	500	0	0	
GRNV RVGR	8.78	No	-1.500	500	0	0	RIVER GREEN
RVGR GRNV	8.79	No	-2.500	500	0	0	
RVGRN LKS	9.60	No	-1.500	520	0	0	
FRWY&KNS	31.67	No	-3.000	500	0	0	
KNSGTN4X2	31.67	No	-1.000	500	0	0	

213648-044

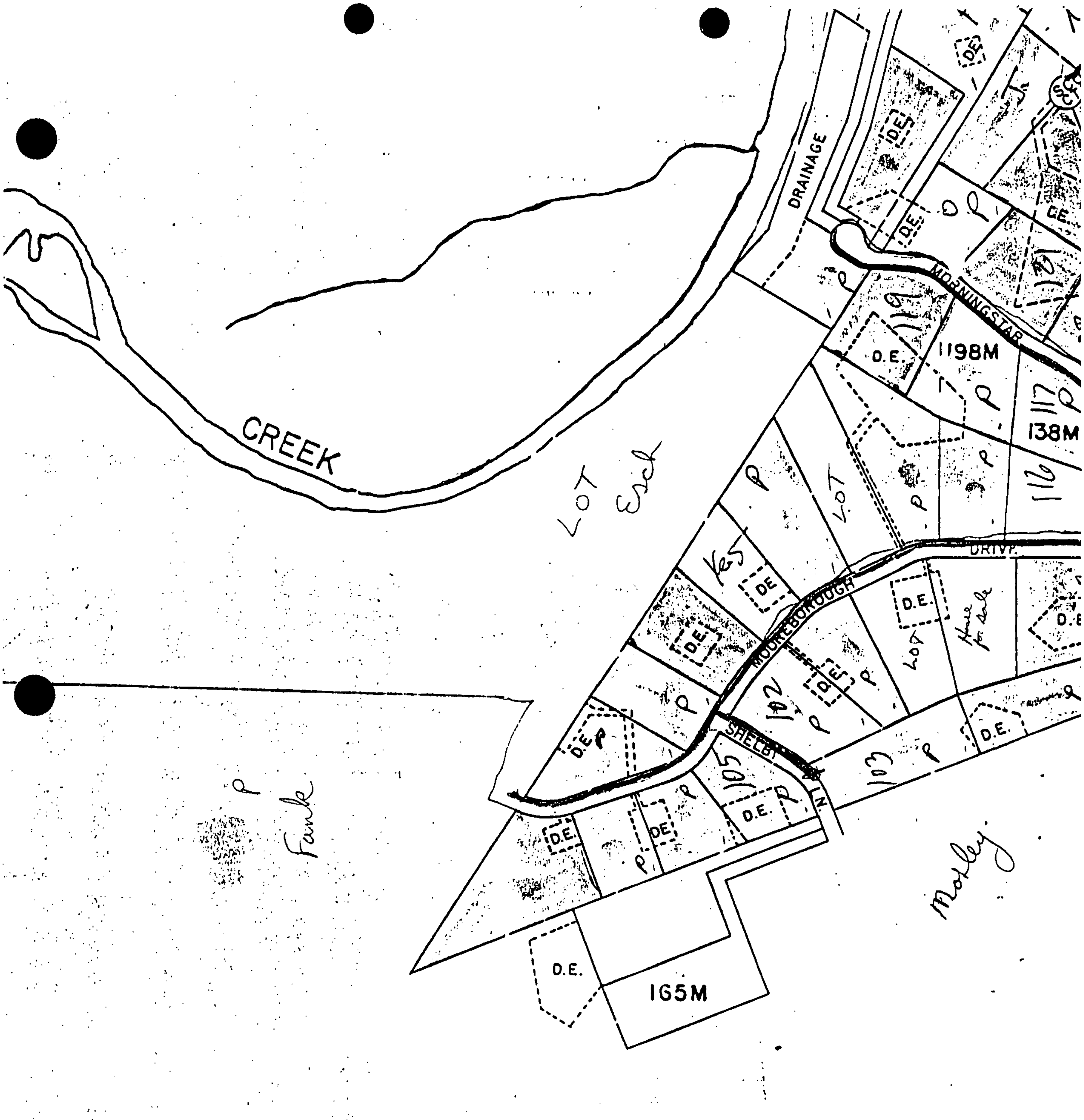
Drakesborough

63 houses Signed Up

11-19-96 Revised

SAXON - 933
Drakesborough - 3281
Scottsborough Ct. - 2000
Scottsborough Circle - 2375
TONY - 460
Marksdale - 775
Fisher - 1130
Mooreborough - 2600
Shelby - 480
Morningstar - 1060

15,094


CREEK
DRAINAGE
MORNINGSTAR
MOOREBOROUGH
1198M
138M
165M
D.E.
LOT
102
103
105
116
117
119

01/12/98 17:20:46 CAPITAL APPROPRIATION GENERATION SYSTEM CAG400

ENTRY: 11/24/97 1998 AFE REQUEST FORM WITH DETAIL STATUS: A

TYPE: N

NUMBER: U05011-001 TITLE: 546-[redacted]

O- 'SUB CO: 40 WESTERN KENTUCKY GAS
R .E/DIV: 9 WESTERN KENTUCKY GAS
SP CTR: 5152700 MADISONVILLE OPERATIONS
OP LOC: 546 RURAL MADISONVILLE
LINE NO.: 9021-500 ADDRESS: ISLAND 4"

CONTRACT: N/A
START DATE: 1/2/1998 COMPLETE DATE: 3/28/1998

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	918125	36701	10	0	268,378	0	268,378-	268,378

[redacted] 21,000' 4" STEEL

21,000' 4" STEEL PIPE	73,500
STORES EXPENSE 35%	25,725
OTHER MATERIALS	17,753
STORES EXPENSE 35%	6,214
RIGHT OF WAYS (ACQ.&FILING)	11,090
CONTRACT LABOR	119,696
ENGINEERING & INSPECTION	13,400
12" TAP	1,000

RED APPROVAL AMT: 268,378 NORMAL APPROVAL AMT: 0

DESCRIPTION:
IS TRANSMISSION LINE(91-215-00) WILL PROVIDE GAS TO [redacted] NEW INDUSTRIAL CUSTOMER IN ISLAND, KENTUCKY. FUTURE EXTENSIONS IN THIS AREA ARE PROBABLE AND WILL MOST LIKELY INCLUDE SERVING [redacted] AND THE TOWN OF ISLAND.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O
TAX AUTHORITY: 92502 SACRAMENTO CTY & COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT W BEST		
APPROVED	ROBERT W BEST	1/7/98	09:29
APPROVED	JOHN CHARLES GOODMAN	1/7/98	07:49

I CONCUR AND RECOMMEND APPROVAL. PROJECT IS SECURED BY A LINE DEPOSIT.

APPROVED	ROBERT EARL FISCHER	1/6/98	07:50
APPROVED	RICHARD L KISSINGER	12/19/97	13:00

RECOMMEND APPROVAL TO INSTALL 21,000 FT OF 4 INCH STEEL TO SERVE THESE TWO INDUSTRIES AND THE FUTURE SERVICE OF THE TOWN OF ISLAND. THIS UNBUDGETED PROJECT COMES IN AT APPROXIMATELY $12.78 PER FOOT TO INSTALL, HOWEVER AS NOTED IN PREVIOUS COMMENTS THE NECESSARY FUNDING HAS BEEN PROCURRED BY THE COUNTY AND DEPOSITED WITH WKG FOR CONSTRUCTION COSTS. THE ASSOCIATED DEPOSIT WILL BE REFUNDED PER THE AGREEMENT BASED ON FUTURE USAGE.

SENT	DONALD E GRIFFITH	12/19/97	11:57

FOR REVIEW AND APPROVAL.

S T	ROGER L GARMS	12/18/97	15:19

PLEASE REVIEW AND COMMENT.

SENT	DONALD E GRIFFITH	12/18/97	09:25

FOR APPROVAL. PIPELINE NUMBER HAS BEEN CHANGED TO TRANSMISSION LINE

NUMBER. DOLLAR AMOUNTS HAVE BEEN VERIFIED. RECOMMEND APPROVAL.

SENT EDDIE G HAZZARD 12/18/97 07:03

PLEASE REVIEW.

SENT DAVID H DOGGETTE 12/17/97 22:20

TECHNICAL REVIEW COMPLETED AND APPROVED. BASED ON THE BUSINESS DEVELOPMENT POTENTIAL FOR THIS PROJECT, I RECOMMEND THAT WE MOVE FORWARD WITH SEEKING APPROVAL FOR FUNDING OF THIS INDUSTRIAL EXTENSION PROJECT.

SENT GARY L SMITH 12/17/97 14:03

THIS EXTENSION WILL SERVE TWO INDUSTRIES, [redacted] AND THE [redacted]. THE COMBINED NATURAL GAS REQUIREMENTS FOR THESE PLANTS IS PROJECTED TO BE 200,000 TO 300,000 MCF PER YEAR. MCLEAN COUNTY, TRADITIONALLY A HIGH UNEMPLOYMENT AREA, IS DEVELOPING THE AREA FOR FUTURE INDUSTRIAL DEVELOPMENT AND HAS SECURED FUNDING NECESSARY TO DEPOSIT $276,000 FOR WKG'S CONSTRUCTION UNDER A STANDARD INDUSTRIAL MAIN EXTENSION AGREEMENT. IF PROJECTED CUSTOMER DEMAND IS REALIZED, THE PROJECT WILL PRODUCE AN AFTER-TAX RETURN ON EQUITY OFMORE THAN 100% TO WKG. EXPEDIENT COMPLETION OF THE INSTALLATION ISSOUGHT BY COUNTY OFFICIALS. I REQUEST AND RECOMMEND APPROVAL OF THIS AFE.

SENT DAVID H DOGGETTE 12/14/97 18:12

PLEASE PROVIDE INFORMATION REGRDING THE BUSINESS DEVELOPMENT ASPECTS OF THIS REQUEST.

SENT DOUGLAS E STEARNS 12/12/97 15:24

RECOMMEND APPROVAL. FLOW STUDY, ESTIMATE & DRAWINGS ARE COMPLETE AND INCLUDED IN THE BACK-UP MATERIAL. MCLEAN CO. WROTE A CHECK TO COVER R-O-W ACQUISITION COSTS.

SENT BELINDA J BELL 12/9/97 11:55

RECOMMEND APPROVAL. THIS TRANSMISSION LINE WILL BE QUALIFIED FOR THE SAME M.A.O.P. AS THE 12" LINE, 960 PSI. THIS LINE WILL SERVE THE [redacted] NEAR THE TOWN OF ISLAND. THIS PIPELINE WILL ALSO MAKE GAS SERVICE AVAILABLE TO [redacted] THE TOWN OF ISLAND FOR FUTURE EXTENSIONS.

SENT EDDIE G HAZZARD 11/24/97 13:45

FOR TECHNICAL REVIEW AND COMMENT.

DISTRIBUTION: NELSON GARMS HAZZARD DGRIFFIT KISSINGE TBERRY

INSTRUCTIONS:

THIS IS THE ORIGINAL AFE. PLEASE SIGN THIS DOCUMENT AND RETURN TO PLANT ACCOUNTING.

11/24/97 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300

ENTRY: 11/24/97 STATUS: E

ISCAL YEAR: 1998 TYPE: N

NUMBER: U05011-001 546-[redacted]

OP/SUB CO: 40 WESTERN KENTUCKY GAS

RATE/DIV: 9 WESTERN KENTUCKY GAS

RESP CTR: 5152700 MADISONVILLE OPERATIONS

PROP LOC: 546 RURAL MADISONVILLE

LINE NO.: 9121-500 ADDRESS: ISLAND 4"

CONTRACT: N/A

START DATE: 1/2/1998 COMPLETE DATE: 3/28/1998

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	[redacted]	36701	10	0	0	268,378	268,378-	268.378
	[redacted] 21,000' 4" STEEL							
	21,000' 4" STEEL PIPE							73,500
	STORES EXPENSE 35%							25,725
	OTHER MATERIALS							17,753
	STORES EXPENSE 35%							6,214
	RIGHT OF WAYS (ACQ.&FILING)							11,090
	CONTRACT LABOR							119,696
	ENGINEERING & INSPECTION							13,400
	12" TAP							1,000

RED APPROVAL AMT: 268,378 NORMAL APPROVAL AMT: 0

DESCRIPTION:

THIS TRANSMISSION LINE(91-215-00) WILL PROVIDE GAS TO METSPAR ALUMINUM NEW PLANT IN ISLAND, KY.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O

TAX AUTHORITY: 92502 SACRAMENTO CTY & COM SCH

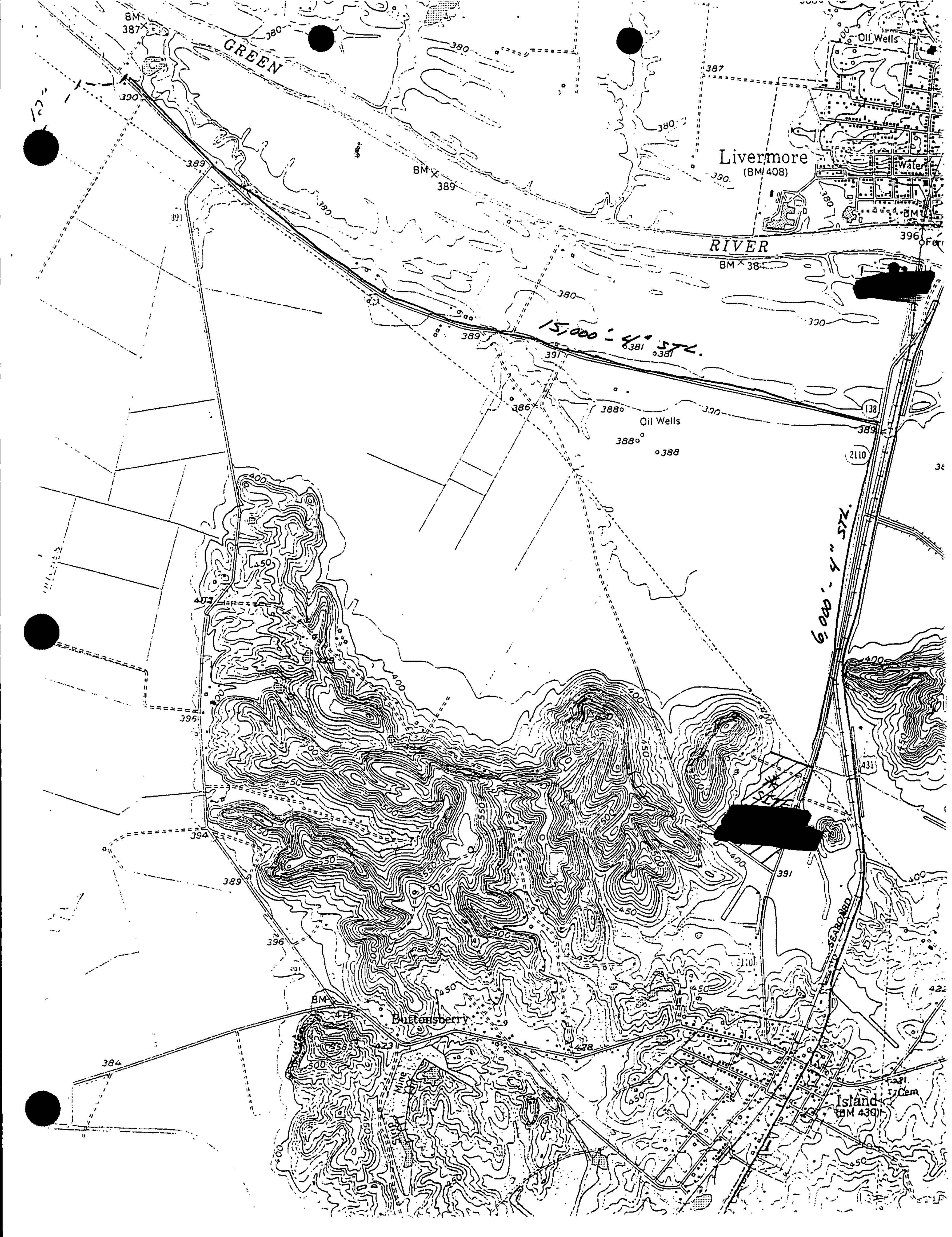
STATUS	NAME	DATE	TIME
CURRENT USER:	BELINDA J BELL		
SENT	EDDIE G HAZZARD	11/24/97	13:45

FOR TECHNICAL REVIEW AND COMMENT.

DISTRIBUTION: NELSON GARMS HAZZARD FOGLE DGRIFFIT KISSINGE

INSTRUCTIONS:

ent to: BELL - BELL, BELINDA J. (to)



GREEN
RIVER
Livermore
(BM 408)
Oil Wells
Water
12"
15,000' - 4" STL.
6,000' - 4" STL.
Oil Wells
[redacted]
[redacted]
Buttonsberry
Island
(BM 430)
Cem
Strip Mine
SEABOARD
138
2110
431

WESTERN KENTUCKY GAS COMPANY
[redacted] – ISLAND, KY
GAS FACILITIES ESTIMATE
OPTION #1

PIPELINE FACILITIES DESIGNED FOR 960 PSI Item	Qty.	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	3	Days	$	150.00	$	450
Acquisition Easement	910	Rods		5.00		4,550
Damages, Crops, Timber, Road, etc.	910	Rods		3.00		2,730
Permits, Filing & Recording Fees	4	Each		15.00		60
Road Crossing Permit	2	Each		100.00		200
Railroad Crossing Permit	0	Each		3,000.00		0
				Total R-O-W	$	7,990
MATERIALS						
4" Pipe, Gr. B, .188 wt, BFW, DRL Joints, FBE Coated	15,000	Lin. Ft.	$	3.50	$	52,500
4" Line Valve, ANSI 600 (1440 WP)	3	Each		1,300.00		3,900
Wrench Operated Valve Extension	1	Each		300.00		300
2" Blow-off Valve, ANSI 600	2	Each		500.00		1,000
4 " Weld Fittings	10	Each		9.40		94
4"-90 Degree 3R Weld Ells	2	Each		130.00		260
Joint Wrap – Tape (4")	100	Rolls		29.36		2,936
– Primer	4	Gallon		31.38		126
Anodes – 17 lb.	15	Each		62.00		930
Cathodic Protection Test Station	3	Each		17.20		52
Marker Post and/or Sign	10	Each		50.00		500
Misc. Materials & Expendables	1	Lump		2,000.00		2,000
				Total Materials	$	64,598

WESTERN KENTUCKY GAS COMPANY
[redacted] – ISLAND, KY
GAS FACILITIES ESTIMATE
OPTION #1

PIPELINE FACILITIES
DESIGNED FOR 960 PSI

Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
Install Line Pipe	15,000	Lin. Ft.	$	4.40	$	66,000
Pipe Fitting and Extra Labor for Valve Installations	3	Each		200.00		600
ROW Clearing	1	Lump		1,000.00		1,000
Rock Excavation	10	Cu. Yd.		50.00		500
HWY Crossing	2	Each		1,000.00		2,000
Creek Crossing	1	Each		3,000.00		3,000
Pressure Testing & De–watering	1	Lump		3,500.00		3,500
Install Cathodic Protection	15	Each		16.00		240
WKG Weld Inspector	20	Days		240.00		4,800
Extra Work	1	Lump		3,000.00		3,000
				Total Con. Labor	$	84,640
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	6	Lump	$	200.00	$	1,200
Field Inspection	20	Days		240.00		4,800
Pigging and Testing	3	Days		240.00		720
				Total Eng. & Insp.	$	6,720
				PROJECT SUB–TOTAL	$	163,948

OVERHEADS

35 % Stores	$	22,609
22.71 % Labor Overhead	$	1,526
15 % WKG Overhead	$	28,213
16 % Corporate Overhead	$	30,093
FACILITIES TOTAL	$	246,389
12" Tap	$	1,000
PROJECT TOTAL	$	247,389
PROJECT TOTAL LESS ATMOS O.H. & STORES	$	194,557

WESTERN KENTUCKY GAS COMPANY
[redacted] – ISLAND, KY
GAS FACILITIES ESTIMATE
OPTION #2

PIPELINE FACILITIES DESIGNED FOR 960 PSI Item	Qty	Units		Unit Cost		Extended Cost
RIGHTS-OF-WAY						
Contract ROW Agent	1	Days	$	150.00	$	150
Acquisition Easement	365	Rods		5.00		1,825
Damages, Crops, Timber, Road, etc.	365	Rods		3.00		1,095
Permits, Filing & Recording Fees	2	Each		15.00		30
Road Crossing Permit	0	Each		100.00		0
Railroad Crossing Permit	0	Each		3,000.00		0
				Total R-O-W	$	3,100
MATERIALS						
4" Pipe, Gr. B, .188 wt, BFW, DRL Joints, FBE Coated	6,000	Lin. Ft.	$	3.50	$	21,000
4" Line Valve, ANSI 600 (1440 WP)	1	Each		1,300.00		1,300
Wrench Operated Valve Extension	0	Each		300.00		0
2" Blow-off Valve, ANSI 600	2	Each		500.00		1,000
4 " Weld Fittings	4	Each		9.40		38
4"-90 Degree 3R Weld Ells	1	Each		130.00		130
Joint Wrap - Tape (4")	50	Rolls		29.36		1,468
- Primer	2	Gallon		31.38		63
Anodes - 17 lb.	6	Each		62.00		372
Cathodic Protection Test Station	2	Each		17.20		34
Marker Post and/or Sign	5	Each		50.00		250
Misc. Materials & Expendables	1	Lump		1,000.00		1,000
				Total Materials	$	26,655

WESTERN KENTUCKY GAS COMPANY
[redacted] – ISLAND, KY
GAS FACILITIES ESTIMATE
OPTION #2

PIPELINE FACILITIES
DESIGNED FOR 960 PSI

Item	Qty.	Units		Unit Cost		Extended Cost
CONTRACT LABOR						
Install Line Pipe	6,000	Lin. Ft.	$	4.40	$	26,400
Pipe Fitting and Extra Labor for Valve Installations	1	Each		200.00		200
ROW Clearing	1	Lump		1,000.00		1,000
Rock Excavation	10	Cu. Yd.		50.00		500
HWY Crossing	0	Each		1,000.00		0
Creek Crossing	0	Each		3,000.00		0
Pressure Testing & De–watering	1	Lump		2,000.00		2,000
Install Cathodic Protection	6	Each		16.00		96
WKG Weld Inspector	14	Days		240.00		3,360
Extra Work	1	Lump		1,500.00		1,500
				Total Con. Labor	$	35,056
ENGINEERING & INSPECTION						
Surveying, Drafting, ROW Plats, Alignments, Plan/Profiles	3	Lump	$	200.00	$	600
Field Inspection	14	Days		240.00		3,360
Pigging and Testing	1	Days		240.00		240
				Total Eng. & Insp.	$	4,200
				PROJECT SUB–TOTAL	$	69,011

OVERHEADS

35 % Stores	$	9,329
22.71 % Labor Overhead	$	954
15 % WKG Overhead	$	11,894
16 % Corporate Overhead	$	12,687
FACILITIES TOTAL	$	103,875
PROJECT TOTAL	$	103,875
PROJECT TOTAL LESS ATMOS O.H. & STORES	$	81,729

[redacted]4" PIPELINE
ISLAND, KY

4-INCH PIPELINE

Line Length		Pipe	O.D.	4.500
Ft.	21,000		I.D.	4.124
Miles	3.98		Wall	.188
Rods	1,273		Grade	API B
			lbs/ft.	8.660

Joint Lengths Pipe - ft.	40
Coating Skotchkote 206N or equal with 2" cutback	
Joint wrap 2" Tapecoat CT cold applied with CT primer	
Line to be qualified for	960
Construction Class	3
Proposed M.A.O.P.	960
Internal Pressure at Minimum Yield (SMYS)	2924
Standard Mill Test Pressure	1800
20% of Minimum Yield	585
% of SMYS at MAOP	32.8
Internal Pressure at 90% SMYS	2632
X-Ray Inspection Required	No
Test Pressure	1440
Test Medium	Water
Gallons of water per foot	.6939
Line capacity in gallons of water	14,572
Valves and fittings pressure rating WOG	1440
Valves and fittings pressure rating ANSI	600
Above Ground Piping wall thickness	.237
Valve I.D.	4.026
Fitting I.D.	4.026
Fitting wall thickness	.237
Valve wall thickness	.237
Pipe wall/Valve wall mismatch	.049
Pipe wall/Fitting wall mismatch	.049
Will Pipeline be set up for smart pigging	Yes
Casing size	N/A
Casing length ft.	N/A
Casing wall thickness	N/A
Weight of water per ft.	N/A
Pipe Buoyancy lbs.	N/A
Concrete River Weights Size	N/A
Concrete River Weights in Air lbs. each	N/A
Concrete River Weights in water lbs. each	N/A
Concrete River Weights Spacing Ft.	N/A
Right of Way Width Ft.	30

PIPELINE QUALIFICATION RECORD

District Madisonville Town Rural McLean County (Island)

Date 12/09/1997 A.F.E. No. U05011-001 Appro No. ________

Appropriation Title [redacted]" Transmission Pipeline

PIPE DATA

Class Location 3 Type Construction C

Type Pipe: ( ) Plastic ( ) Cont weld (X) Gr B ( ) Other ________

Pipe Size: 4" Wall Thickness .188 Press. at Min Yield 2924

DESIGN & TEST DATA

Design Pressure 960 Percent of SMYS 32.8

Pressure Rating of Valves & Fittings 600 ANSI OR 1440 WOG

Leak Test: Press. PSIG 100 % SMYS 3.42 Medium AIR

Strength Test: Press. PSIG 1440 % SMYS 49.25 Medium Water

X-Ray Inspection: (X) is not ( ) is required on ____ % of welds

Length of Line 21,000' Line Capacity in gallons of water 14,572

Special Instructions LINE REQUIRES MINIMUM API STANDARD 1104 ARC WELDER QUALIFICATION. LINE TO BE PIGGED AND CLEANED PRIOR TO TESTING. EXERCISE CAUTION AS TEST PRESSURE EXCEEDS 20 % SMYS.

Signed: Belinda J. Bell

****

TEST DATA

Leak Test: Test Medium ________ Duration of Test ________ hours

Start of Test Press. ________ tg ____ ta ____ Time ____ date ________

End of Test Press. ________ tg ____ ta ____ Time ____ date ________

Strength Test: Test Medium ________ Duration of Test ________ hours

Start of Test Press. ________ tg ____ ta ____ Time ____ date ________

End of Test Press. ________ tg ____ ta ____ Time ____ date ________

Pipeline is: Accepted ________ Rejected ________

Number of Pig Runs ____ Results of First Pig ________

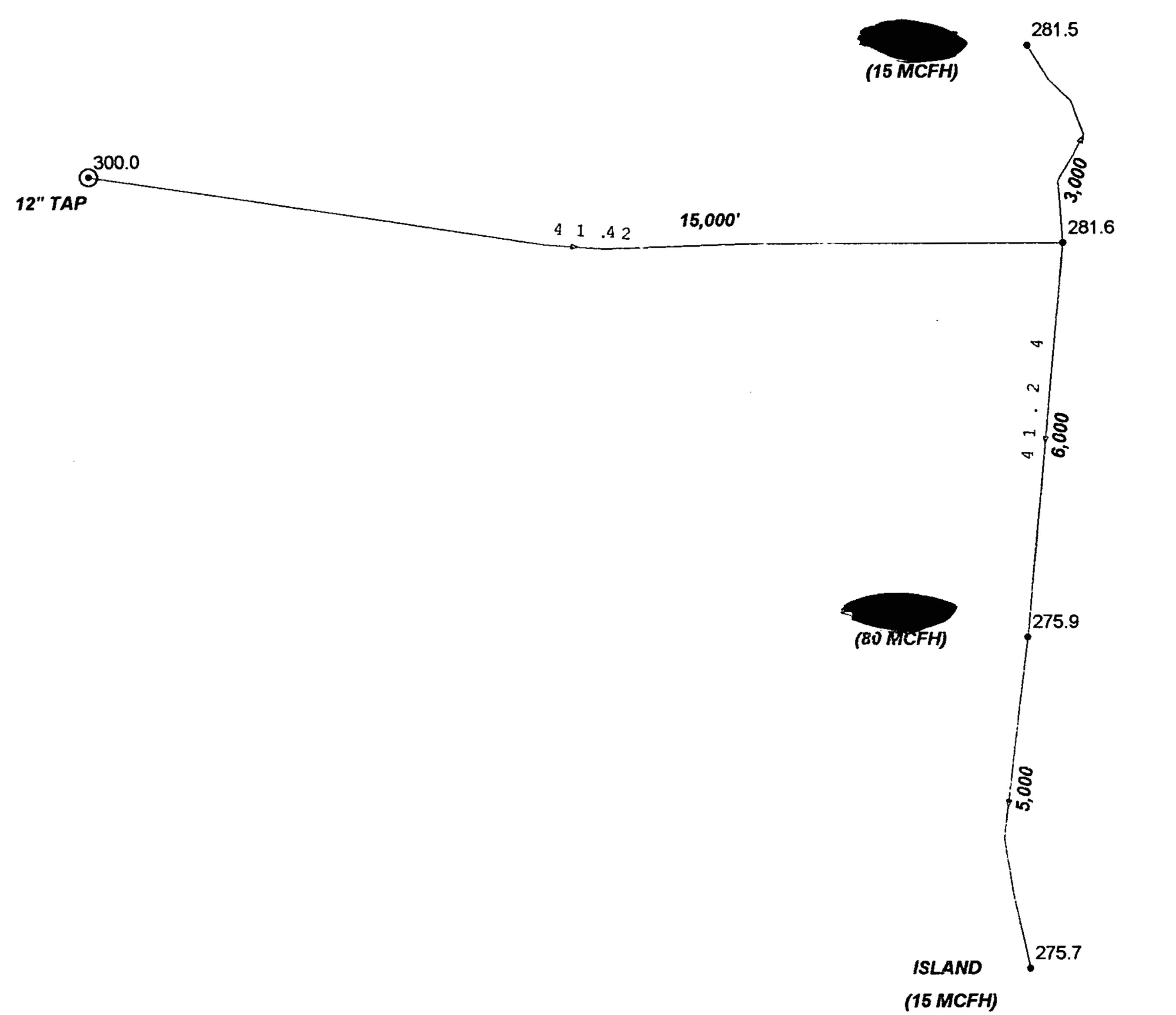
Results of Last Pig ________

Pipeline ( ) was ( ) was not purged in accordance with Company Standards. The materials, methods of construction and testing performed qualify this pipeline to to operate at a maximum of ______ PSI.

Inspector ________

tg = ground temperature
ta = atmospheric temperature

ISLAND FLOW STUDY



SCHEMATIC
---RANGE---- COUNT
ALL ELEMENTS 4
NODE ANN:PRES
ELEM ANN:ID

State: BALANCED

Sep 25, 1997

Corners: (FEET)
UL:(-18943,11071)
LL:(-18943,-6570)
UR:(5481,11071)
LR:(5481,-6570)

*** REQUESTOR: BWOODWAR - WOODWARD, BILL OPERATIONS ***

*** SYSM INBASKET PRINT ***

MESSAGE ID: 32513174401 DATE: 11/21/97 TIME: 01:17pm PRIORITY: 000

TO: BWOODWAR - WOODWARD, BILL
MANAGER-WKG
OPERATIONS
P.O. BOX 528
HOPKINSVILLE, KY. 42240

FROM: BEST - Best, Robert W.
Chrmn, President & CEO
Executive
5430 LBJ Frwy, Suite 1800
Dallas, TX 75240

SUBJECT: AFE U04958001 - APPROVED

11/21/97 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 10/16/97 AFE HAS RCVD FINAL APPRVL BY: ROBERT W BEST STATUS: A
FISCAL YEAR: 1998 TYPE: N

NUMBER: U04958-001 537- COMMERCE IND. PARK MAIN EXT.
OP/SUB CO: 40 WESTERN KENTUCKY GAS
RATE/DIV: 9 WESTERN KENTUCKY GAS
RESP CTR: 5602700 BOWLING GREEN OPERATIONS
PROP LOC: 537 HOPKINSVILLE
LINE NO.: 9537-231 ADDRESS: HOPKINSVILLE

CONTRACT: N/A
START DATE: 10/20/1998 COMPLETE DATE: 12/20/1998

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	918032	37601	10	0	465,235	0	465,235-	465,235
15,250 FT. OF 8" - COMMERCE PARK								
15,250 FT. OF 8" .188 PC PIPE								101,870
STORES EXPENSE 35%								35,655
MATERIAL								10,339
STORES EXPENSE 35%								3,619
RIGHT OF WAYS, PERMITS, & DAMAGES								3,315
COMPANY LABOR								8,737
CONTRACT LABOR								301,700
A	918033	37601	10	0	96,387	0	96,387-	96,387
5600 FT. OF 6" - COMMERCE PARK								

5600 FT. OF 6" .188 PC PIPE	27,384
STORES EXPENSE 35%	9,584
MATERIAL	6,773
STORES EXPENSE 35%	2,371
COMPANY LABOR	3,485
CONTRACT LABOR	46,790

RED APPROVAL AMT: 561,622 NORMAL APPROVAL AMT: 0

DESCRIPTION:
INSTALL 15,250 FT. OF 8" STEEL PIPE ON HIGHWAY 41 BEGINNING WITH TIE-IN AT EXISTING 6" STEEL DISTRIBUTION MAIN NEAR THE PRESENT INDUSTRIAL PARK AND CONTINUE TO THE PROPERTY LINE OF THE NEWLY DEVELOPED COMMERCE INDUSTRIAL PARK. ESTIMATED COST FOR THE 8" STEEL PROJECT, LESS STORES AND CORPORATE EXPENSES -- $500,268. THE 5600 FT. OF 6" STEEL PIPE WILL BE INSTALLED THROUGHOUT COMMERCE PARK. ESTIMATED COST FOR THE 6", LESS STORES AND CORPORATE EXPENSES, -- $99,854. THIS EXTENSION WILL PROVIDE GAS SERVICE TO SEVERAL NEW INDUSTRIAL CUSTOMERS CURRENTLY LOCATING IN THE COMMERCE PARK AREA. PAPERWORK WAS SENT WITH ORIGINAL 1997 AFE# U04568-001, MARCH 25,1997.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: I

TAX AUTHORITY: 90602 HOPKINSVILLE CTY & COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT W BEST		
APPROVED	ROBERT W BEST	11/21/97	13:16
APPROVED	JOHN CHARLES GOODMAN	11/20/97	14:21

I CONCUR AND RECOMMEND APPROVAL.

APPROVED	ROBERT EARL FISCHER	11/12/97	08:27

RECOMMEND APPROVAL.

APPROVED	JOHN KEVIN AKERS	10/29/97	11:47

RECOMMEND APPROVAL OF THIS PROJECT. GIVEN THE ECONOMICS OF THE PROJECT, I AGREE WITH ENGINEERINGS PIPE SIZE RECOMMENDATIONS. INSTALLATION FOR INITIAL TESTING AND PLANT PROTECTION FOR THE TUBE PLANT MAKES THIS A PRIORITY PROJECT FOR THE EAST REGION BEFORE WINTER BEGINS. CREWS ARE READY TO START THE PIPELINE INSTALLATION UPON PROJECT APPROVAL.

APPROVED	JERRY W HARMON	10/29/97	11:21

RECOMMEND APPROVAL. LINE IS NEEDED TO SERVE FIVE INDUSTRIAL PLANTS UNDER CONSTRUCTION AT THIS TIME.

SENT	GARY L SMITH	10/29/97	09:38

FOUR INDUSTRIES ARE CURRENTLY CONSTRUCTING NEW FACILITIES, INCLUDING [redacted], [redacted], [redacted] AND [redacted]. [redacted] AN EXISTING FACILITY, ALSO DESIRES GAS SERVICE. [redacted] THE LARGEST OF THESE CUSTOMERS, DESIRES FIRST SERVICE IN EARLY DECEMBER. WE ARE IN THE PROCESS OF FINALIZING CONTRACTUAL AGREEMENTS WITH THESE PLANTS, WHICH WILL COMBINE TO CONSUME NEARLY 300,000 MCF/YR AT A MAX. HOURLY DEMAND OF 170 MCF. PROJECT ECONOMICS, RECOGNIZING THE STAGED INCREASE IN REQUIREMENTS OVER THE FIRST THREE YEARS, RESULT IN AN AFTER-TAX ROE OF GREATER THAN 15%. I RECOMMEND APPROVAL OF THIS

REQUEST AND ALL REASONABLE EFFORTS TO ENSURE TIMELY INSTALLATION.

SENT	JERRY W HARMON	10/28/97	09:22

PLEASE REVIEW

SENT	JOHN (BILL) W WOODWA	10/28/97	08:29

RECOMMEND APPROVAL. THERE ARE FIVE NEW INDUSTRIAL PLANTS WELL UNDER CONSTRUCTION AT PRESENT TIME. THE POTENTIAL FOR ADDITIONAL CUSTOMER GROWTH IN THIS AREA IS EXCELLENT.

SENT	JERRY W HARMON	10/27/97	17:03

PLEASE REVIEW AND COMMENT

APPROVED	WILLIAM B OOST	10/27/97	14:03
SENT	DAVID H DOGGETTE	10/27/97	10:36

TECHNICAL REVIEW COMPLETE. YOU MAY WANT TO GET BUSINESS DEVELOPMENT VP TO REVIEW AND COMMENT ON THE POTENTIAL FOR USAGE OF THIS EXTENSION.

SENT	DOUGLAS E STEARNS	10/24/97	18:45

RECOMMEND APPROVAL. FLOW STUDIES, DRAWINGS AND PIPE QUALIFICATIONS ARE COMPLETED.

SENT	BELINDA J BELL	10/17/97	09:19

RECOMMEND APPROVAL. THIS EXTENSION WILL PROVIDE GAS SERVICE TO THE NEW COMMERCE PARK WHICH HAS SEVERAL INDUSTRIAL CUSTOMERS CURRENTLY LOCATING THERE. RECOMMEND TO INSTALL 6" MAIN INSIDE THE PARK DUE TO PRESSURE PROBLEMS IN THIS AREA, THE POTENTIAL FOR LOAD GROWTH, AND THE FACT THAT THERE IS LITTLE COST DIFFERENCE BETWEEN 4" AND 6".

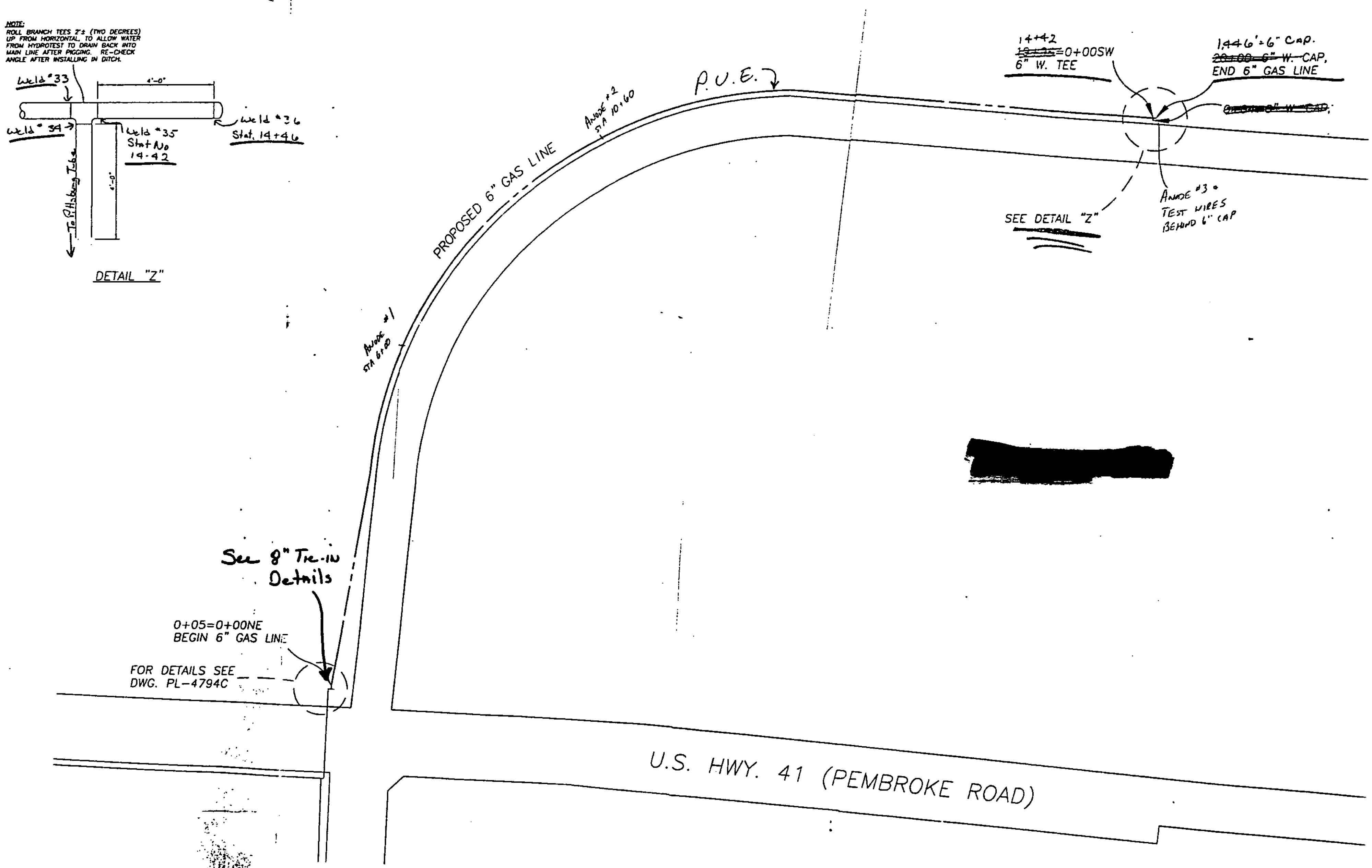
SENT	WILLIAM B OOST	10/16/97	09:24

FOR REVIEW.

DISTRIBUTION: NELSON OOST FOGLE AKERS SCHMIDT HARMON

INSTRUCTIONS:
THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT W BEST .
THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

Sent to:			
	OOST	- OOST, WILLIAM B.	(to)
	NELSON	- NELSON, HAROLD E.	(to)
	FOGLE	- FOGLE, CLYDE B.	(to)
	AKERS	- AKERS, KEVIN	(to)
	SCHMIDT	- Schmidt, Michael C.	(to)
	HARMON	- HARMON, JERRY	(to)
	TOWEN	- OWEN, TIM	(to)
	BENNINGF	- BENNINGFIELD, RONNIE	(to)



NOTE:
ROLL BRANCH TEES 2°± (TWO DEGREES) UP FROM HORIZONTAL, TO ALLOW WATER FROM HYDROTEST TO DRAIN BACK INTO MAIN LINE AFTER PIGGING. RE-CHECK ANGLE AFTER INSTALLING IN DITCH.
Weld #33
Weld #34
Weld #35 Stat No 14-42
Weld #36 Stat. 14+46
4'-0"
4'-0"
To Pittsburg Tube
DETAIL "Z"
PROPOSED 6" GAS LINE
Anode #1 STA 6+00
Anode #2 STA 10+60
P.U.E.
14+42 = 0+00SW
6" W. TEE
1446' = 6" Cap.
6" W. CAP,
END 6" GAS LINE
SEE DETAIL "Z"
Anode #3 • TEST WIRES BEHIND 6" CAP
[redacted]
See 8" Tie-in Details
0+05=0+00NE
BEGIN 6" GAS LINE
FOR DETAILS SEE DWG. PL-4794C
U.S. HWY. 41 (PEMBROKE ROAD)

Western Kentucky Gas Company

MEMORANDUM

WK-742, R-2-86

To: Dave Doggette

From: Belinda Bell

Subject: Hopkinsville Commerce Park

Date: October 31, 1996

This letter is in response to your inquiry concerning providing gas service to the Hopkinsville Commerce Park Industrial Area. I have provided for your consideration, two (2) options for servicing this area. Each option has two (2) phases that will be required to provide optimum flow rates and pressures to the Park. Stoner Flow Studies, Gas Facilities Estimate sheets, and a location map have also been provided as back-up information.

Option #1, Phase #1:

- Install 15,250 feet of 6" steel pipe on HWY 41. Cost of Phase #1 is $392,823 less Atmos O.H. and stores or $480,036 total.
- Extension will provide 13 PSI of pressure at a rate of 35 MCFH.

Summary: This option proposes to run 15,250' of 6" steel main which will tie-into existing 6" main near the Industrial Park at Point "A" on the map provided. The pipeline will extend down HWY 41 to the Commerce Park property line. With no other improvements to the WKG system, this line will cost approximately $392,823 less Corp. O.H. and Stores or $480,036 total to install and provide about 13 PSI of pressure at a rate of 35 MCFH.

Option #1, Phase #2:

- Take out existing station. Uprate 8" and 6" main to 150 PSI. Revise four (4) existing meter loops. Install three (3) individual small regulator stations. Cost of Phase #2 = $181,330 less Atmos Corp. O.H. & stores or $209,700 total. Total Project Cost of Phase #1 & #2 = $574,153 less Atmos O.H. & stores or $689,736 total.
- Improvements plus the 6" main extension will provide a pressure of about 17 PSI at a rate of 95 MCFH.

Summary: This option proposes to take out the station currently located at the corner of the Pennyrile Parkway and Calvin Drive (Point "B" on the map provided). With the removal of this station, the 8", 4", and 6" pipelines downstream will need to be uprated to 150 PSI. There are also three (3) small regulator stations that would have to be installed and four (4) existing meter loops requiring revisions. These improvements alone will cost approximately $181,330 less Atmos O.H. and stores or $209,700 total. These improvements, along with the 15,250 feet of 6" steel, will cost about $574,153 less Atmos O.H. and stores or $689,736 total and provide the Park with 17 PSI of pressure at a rate of 95 MCFH.

Option #2, Phase #1:

- Install 1,850 feet of 4" plastic and 12,700 feet of 6" steel next to the CSX Railroad. Cost of Phase #1 is $359,687 less Atmos O.H. and stores or $438,527 total.
- Extension will provide 16 PSI of pressure at a rate of 15 MCFH.

Summary: This option proposes to install 1,850 feet of 4" plastic and 12,700 feet of 6" steel main which will tie-into an existing 4" steel main on Casky Lane, downstream of the existing Industrial Park (Point "C"). This pipeline will extend down the CSX Railroad to the Commerce Park property line. With no other improvements to the current WKG system, this line will cost about $359,687 less Atmos O.H. and stores or $438,527 total to install and provide 16 PSI at a rate of 15 MCFH.

Option #2, Phase #2:

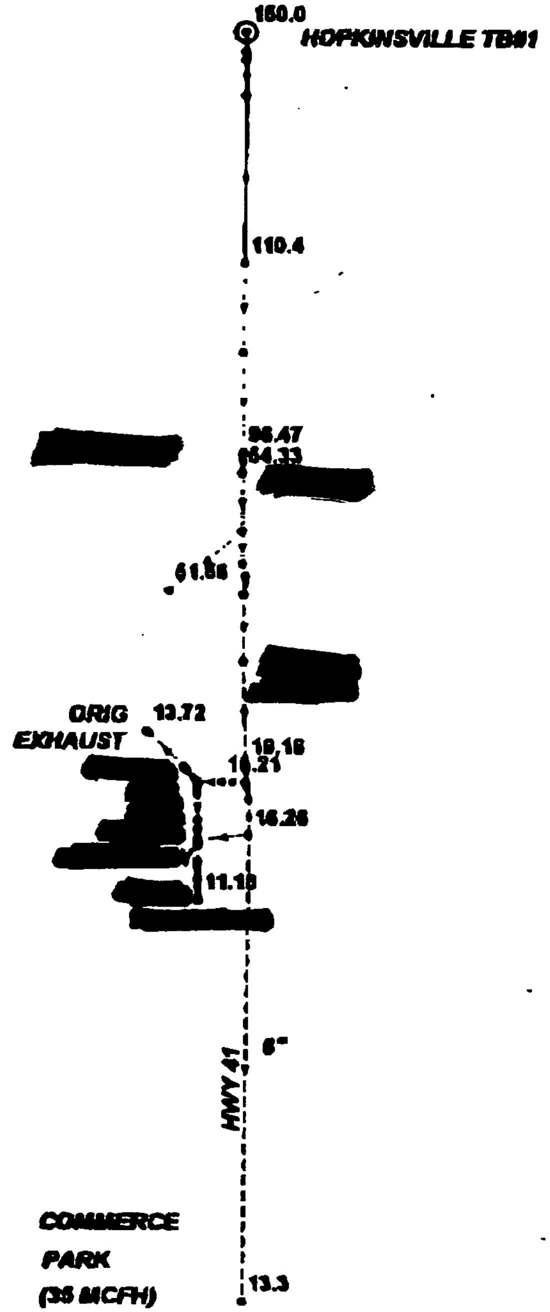
- Install 9,500 feet of 6" steel main running northwest along the CSX Railroad and tie-into our existing 4" steel main. Relocate the existing station, uprate the 8", 6" and 4" pipelines to 150 PSI, and revise three (3) meter loops. Cost of Phase #2 = $305,105 less Atmos O.H. and stores or $368,347 total. Total Project Cost of Phase #1 & Phase #2 = $664,792 less Atmos O.H. and stores or $806,874 total.
- Improvements plus the 6" main extension will provide a pressure of 18 PSI at a rate of 120 MCFH.

Summary: This option proposes to tie-into the 6" in Phase #1 at Casky Lane (Point "D"), install 9,500 of 6" steel main running northwest along the CSX Railroad, and tie-into the existing 4" steel main near Bradshaw Road (Point "E"). Further improvements require the relocation of the existing station from Calvin Drive (Point "B") to the corner of Bradshaw Road and HWY 41 (Point "F"). This station relocation will require revisions to three (3) existing meter loops along with the uprating of the existing 8", 6" and 4" pipelines to 150 PSI. These improvements will cost about $305,105 less Atmos O.H. and stores or $368,347 total. The improvements along with the 1,850 feet of 4" plastic and the 12,700 feet of 6" steel will cost about $664,792 less Atmos O.H. and stores or $806,874 total, providing the Park with 18 PSI of pressure at a rate of 120 MCFH.

The following is a **Pressure vs. Flow Rate** chart for **Option #1, Phase #1**. These pressures and rates correspond to the results that can be expected at the end of the 15,250 feet of 6" pipeline to be installed to the Commerce Park property line with no other improvements to the existing WKG system.

PRESSURE (PSI)	FLOW RATE (MCFH)
10	39
15	32
20	24
25	12
30	<1

HOPKINSVILLE COMMERCE PARK HWY 41
OPTION 1 - PHASE 1 (15,250' - 6")



HOPIND
PRESSURE
(PSIG)

---RANGE----		COUNT
BELOW	38.9	24
38.9	66.7	6
66.7	94.5	1
94.5	122.2	2
ABOVE	122.2	4

MIN = 11.13
MAX = 150.00
NODE ANN:PRES
ELEM ANN:OFF

State: BALANCED

Oct 30, 1996

Corners: (FEET)
UL:(-27995,3128)
LL:(-27995,-38995)
UR:(30324,3128)
LR:(30324,-38995)

04/22/98 CAPITAL BUDGET GATHERING SYSTEM CB0410
ENTRY: 03/23/98 1999 BUDGET REQUEST FORM

CONTROL NUMBER: 217123 537 - COMMERCE PARK 6" & 8" UPRATE STATUS: S
OP/SUB CO: 40 WESTERN KENTUCKY GAS REQ TYPE: P
RATE/DIV: 9 WESTERN KENTUCKY GAS PRIORITY: 1
RESP CTR: 5602700 BOWLING GREEN OPERATIONS
PROP LOC: 537 HOPKINSVILLE
LINE NUMBER: 9537-231 HOPKINSVILLE

	BUDGET NO	ITEM STAT	QTY	DESCRIPTION	UNIT COST/ CREDITS	TOTAL COS
A	36701	20	1	UPRATE 6" & 8" - COMMERCE PARK	250000.00	250,000

TOTAL: APRV: 250,000 DEF: REJ: TOT: 250,000

------ DESCRIPTION/COMMENTS ------

THIS SYSTEM IMPROVEMENT PROPOSES TO REMOVE THE CALVIN DR. REGULATOR STATION AND UPRATE THE WKG EXISTING PIPING AND FACILITIES FROM 60 PSI TO 150 PSI. WITHNTHIS FACILITY UPRATING, IT WILL BE NECESSARY TO REVISE FOUR (4) METER LOOPS, INSTALL THREE SMALL REGULATOR STATIONS, REMOVE THE EXISTING CALVIN DR. REGULATOR STATION, AND UPRATE THE EXISTING 4", 6", AND 8" STEEL PIPE. THIS SYSTEM IMPROVEMENT WILL BE NECESSARY TO SUPPLY THE COMMERCE PARK AREA. CURRENTLY THE SYSTEM WILL ONLY SUPPLY THE PARK WITH 35 MCFH. PROJECTED LOADS ARE NEARING 180 MCFH. THIS SYSTEM IMPROVEMENT WILL SUPPLY AS MUCH AS 190MCFH, ASSUMING THE CONVERSION OF [redacted] FROM GAS FACILITIES TO ELECTRIC IS COMPLETE. IF THIS CONVERSION IS NOT COMPLETE, 95 MCFH WILL BE THE MAXIMUM RTAE THAT CAN BE EXPECTED AT COMMERCE PARK.

------ APPROVALS ------

STATUS	NAME	DATE	TIME
SEND	JERRY W HARMON	03/30/98	10:28
SEND	WILLIAM B OOST	03/24/98	13:15

------ APPROVAL COMMENTS ------

HARMON PLEASE REVIEW AND COMMENT ON FLOW STUDY.
OOST PLEASE REVIEW.

MESSAGE ID: 011999AE DATE: 04/01/98 TIME: 05:25pm PRIORITY: 000

TO: HARMON - HARMON, JERRY
OPERATIONS MANAGER
OPERATIONS-BG AREA
1020 COLLEGE ST.
PO BOX 598
BOWLING GREEN, KY 42101

FROM: STEARNS - Stearns P.E., Douglas E.
Mgr Engineering Services
ENGINEERING SERVICES
2401 New Hartford Rd

Owensboro, KY 42302

SUBJECT: Reply to Commerce Park

*** Original Author: SCHMIDT - Schmidt, Michael C.; 04/01/98 05:02pm

Following revision of the Hopkinsville Stoner Flow Study, Engineering has concluded that with [redacted] using entire contract load there is zero firm gas available in Commerce Park. The study is based on signed contract load information with existing customers and assumes those with interruptible service are curtailed and those with firm are using their full contract load. It is the determination of this department that zero gas is available under these conditions.

Mike

*** Comments From: BELL - BELL, BELINDA J.; 04/01/98 05:05pm
USING CONTRACT FIRM AND INTERRUPTIBLE LOADS IN THE FLOW STUDY, THERE WILL BE ZERO CAPACITY AT COMMERCE PARK, ASSUMING [redacted] IS USING THEIR FULL CAPACITY OF 150 MCFH. IF ACTUAL PEAK DAY LOADS ARE USED, [redacted] WITH 150 MCFH, THERE SHOULD BE ABOUT 25 MCFH AVAILABLE AT COMMERCE PARK. THE DIFFERENCE IS THE [redacted] WHICH CHANGED THEIR CONTRACT IN 1995 FROM 30 MCFH TO 87 MCFH. THEIR MAXIMUM PEAK USAGE IS THOUGHT TO BE 30 MCFH. ALTHOUGH, THERE COULD POSSIBLY BE SOME CAPACITY FOR COMMERCE PARK, [redacted] WHOSE CURRENT CONTRACT IS FOR 75 FIRM AND 75 INTERRUPTIBLE, REQUESTED ALL FIRM CAPACITY OF 150 MCFH JUST RECENTLY AND WAS DENIED. WITH THIS IN MIND, I BELIEVE WE HAVE TO LEAVE [redacted] AT 150 MCFH WHEN LOOKING AT FLOW STUDIES OF THIS AREA.

BELINDA

Jerry: This is the situation as we see it. The use of peak hour rates gives about 25 MCFH available. The use of contract amounts leaves nothing available for Commerce Park. I recommend the contracts be reviewed to determine if they are appropriate volumes and adjust them if necessary to conform with actual needs.

INTEROFFICE MEMORANDUM

TO:	BARRY WIGGINTON
FROM:	BELINDA BELL
	MIKE SCHMIDT
SUBJECT:	HOPKINSVILLE COMMERCE PARK AVAILABLE CAPACITY
DATE:	04/02/98
CC:	DOUG STEARNS, P.E.

Stoner Flow Study Results

Based on a Stoner Flow Study of existing conditions in the Hopkinsville Commerce Park area, Engineering concludes approximately 0 Mcfh of firm capacity is available. Currently six customers are in the process of locating in the park and have requested gas service. However, the proportion of firm and interruptible service to these customers has yet to be determined. Considering this, it is reasonable to assume each customer will be given no firm capacity and criteria for meter set design should be based upon this assumption. In addition, please design meter sets to operate with a minimum pressure drop.

05/06/97 CAPITAL BUDGET GATHERING SYSTEM CBG410
ENTRY: 02/20/97 1998 BUDGET REQUEST FORM

CONTROL NUMBER: 215688 231-COMMERCE PARK EXTENSION STATUS: A
OP/SUB CO: 40 WESTERN KENTUCKY GAS REQ TYPE: P
RATE/DIV: 9 WESTERN KENTUCKY GAS PRIORITY: 1
RESP CTR: 2010100 MADISONVILLE OFFICE (730)
PROP LOC: 231 HOPKINSVILLE
LINE NUMBER: 9537-231 HOPKINSVILLE

	BUDGET NO	ITEM STAT	QTY	DESCRIPTION	UNIT COST/ CREDITS	TOTAL COST
R	36701	20	15250	HOPTOWN 6" COMMERCE PARK EXT.	23.51	358,528
R	36701	20	8000	COMMERCE PARK INTERNAL PIPING	12.50	100,000
A	36701	20	1	UPRATE EXISTING 6"&8"TO IND.PARK	160076.00	160,076

TOTAL: APRV: 160,076 DEF: REJ: 458,528 TOT: 618,604

----- DESCRIPTION/COMMENTS -----

THIS SYSTEM IMPROVEMENT PROPOSES TO REMOVE THE CALVIN DRIVE REGULATOR STATION AND UPRATE THE WKG EXISTING PIPING AND FACILITIES FROM 60 PSI TO 150 PSI. WITH THIS FACILITY UPRATING, IT WILL BE NECESSARY TO REVISE FOUR (4) METER LOOPS, INSTALL THREE SMALL REGULATOR STATIONS, REMOVE THE EXISTING CALVIN DRIVE REGULATOR STATION, AND UPRATE THE EXISTING 4", 6", AND 8" STEEL PIPE. THIS SYSTEM IMPROVEMENT WILL BE NECESSARY TO SUPPLY THE COMMERCE PARK AREA. CURRENTLY THE SYSTEM WILL ONLY SUPPLY THE PARK WITH 35 MCFH. PROJECTED LOADS ARE NEARING 180 MCFH. THIS SYSTEM IMP. WILL SUPPLY AS MUCH AS 190 MCFH, ASSUMING THE CONVERSION OF [redacted] FROM GAS FACILITIES TO ELECTRIC IS COMPLETE. IF THIS CONVERSION IS NOT COMPLETE, 95 MCFH WILL BE THE MAXIMUM RATE THAT CAN BE EXPECTED AT COMMERCE PARK.

----- APPROVALS -----

STATUS	NAME	DATE	TIME
APPROVED	ROY D PEARSON	04/30/97	11:56
SEND	DAVID H DOGGETTE	04/30/97	11:52
SEND	ROY D PEARSON	04/30/97	11:35
APPROVED	ROGER L GARMS	04/30/97	08:53
SEND	EDDIE G HAZZARD	04/30/97	08:43
SEND	GENE R BAKER	04/23/97	09:41
SEND	BELINDA J BELL	04/23/97	09:18
SEND	EDDIE G HAZZARD	02/20/97	14:18

----- APPROVAL COMMENTS -----

PEARSON APPROVED.

DOGGETTE ROY, I CONCUR WITH THIS REQUEST. SEVERAL INDUSTRIAL CUSTOMERS HAVE ANNOUNCED THEIR INTENTIONS TO MOVE INTO THE NEW INDUSTRIAL AREA OF HOPKINSVILLE, COMMERCE PARK. THE LOAD, AS WE NOW KNOW IT, EXCEEDS CURRENT CAPABILITIES OF THE EXISTING DISTRIBUTION SYSTEM. WE HAVE WORKED OUT A PLAN TO UPGRADE THE EXISTING STEEL TO INCREASE CAPACITY TO THIS AREA. PLEASE APPROVE.

PEARSON PLEASE REVIEW AND PROVIDE YOUR INSIGHT AND COMMENTS.

GARMS RECOMMEND APPROVAL.

HAZZARD PLEASE REVIEW

BAKER	RECOMMEND APPROVAL. AGREE WITH UPGRADING SYSTEM TO OPERATE AT A HIGHER PRESSURE.
BELL	RECOMMEND APPROVAL TO UPRATE THE EXISTING FACILITIES FROM 60 PSI TO 150 PSI. THE COMMERCE PARK 6" MAIN EXTENSION AND INTERNAL PIPING HAVE BEEN REJECTED AS THOSE PROJECTS ARE TO BE INSTALLED IN 1997. THIS SYSTEM IMPROVEMENT WILL BE NECESSARY TO SUPPLY THE COMMERCE PARK ANTICIPATED LOADS OF 180 MCFH. CURRENTLY, 35 MCFH IS THE MAXIMUM RATE THAT CAN BE ACHIEVED. COMPLETELY SUPPLYING THE PARK WILL BE CONTINGENT ON THE CONVERSION OF [redacted] FROM GAS TO ELECTRIC.
HAZZARD	PLEASE REVIEW.

HOPKINSVILLE - COMMERCE PARK SYSTEM IMPROVEMENT FLOW STUDIES

THESE FLOW STUDIES WERE RUN TO DETERMINE THE GAS FLOW RATE AVAILABLE TO THE HOPKINSVILLE COMMERCE PARK AREA THROUGH THE EXISTING WKG FACILITIES AND ALSO BY UPRATING THE SYSTEM FROM 60 PSI TO 150 PSI.

[redacted], A LARGE INDUSTRIAL CUSTOMER IN THE EXISTING INDUSTRIAL PARK, IS IN THE PROCESS OF CHANGING OUT ALL THEIR FACILITIES. THE NEW FACILITIES WILL USE ELECTRICITY INSTEAD OF GAS. THIS TRANSITION FROM GAS TO ELECTRIC WILL SUPPOSEDLY BE COMPLETE IN THE NEXT TWO YEARS.

STUDY #1: THIS STUDY WAS BASED ON EXISTING PEAK DAY CONDITIONS FROM THE HOPKINSVILLE T.B. #1 TO THE NEW COMMERCE PARK AREA. [redacted] FLOW RATE IN THIS STUDY IS 150 MCFH. THE GAS AVAILABLE TO THE PARK WILL BE ABOUT 35 MCFH AT A PRESSURE OF APPROXIMATELY 15 PSI.

STUDY #2: THIS STUDY WAS BASED ON FUTURE PEAK DAY CONDITIONS FROM THE HOPKINSVILLE T.B. #1 TO COMMERCE PARK. [redacted] FLOW RATE IN THIS STUDY IS 0 MCFH. [redacted] MAY USE SOME GAS IN THE FUTURE, BUT IT SHOULD BE MINIMAL AT BEST AND SHOULD NOT IMPACT THIS STUDY SIGNIFICANTLY. THE GAS AVAILABLE TO THE PARK WILL BE ABOUT 85 MCFH AT A PRESSURE OF APPROXIMATELY 15 PSI.

STUDY #3: THIS STUDY WAS BASED ON REMOVING THE CALVIN DRIVE REGULATOR STATION AND UPRATING THE EXISTING PIPING AND FACILITIES FROM 60 PSI TO 150 PSI BETWEEN HOPKINSVILLE T.B. #1 AND THE EXISTING INDUSTRIAL PARK. CURRENT PEAK DAY LOADS WERE ALSO USED IN THIS STUDY [redacted] FLOW RATE IS 150 MCFH). THE GAS AVAILABLE TO THE COMMERCE PARK AREA WILL BE ABOUT 95 MCFH AT A PRESSURE OF APPROXIMATELY 15 PSI.

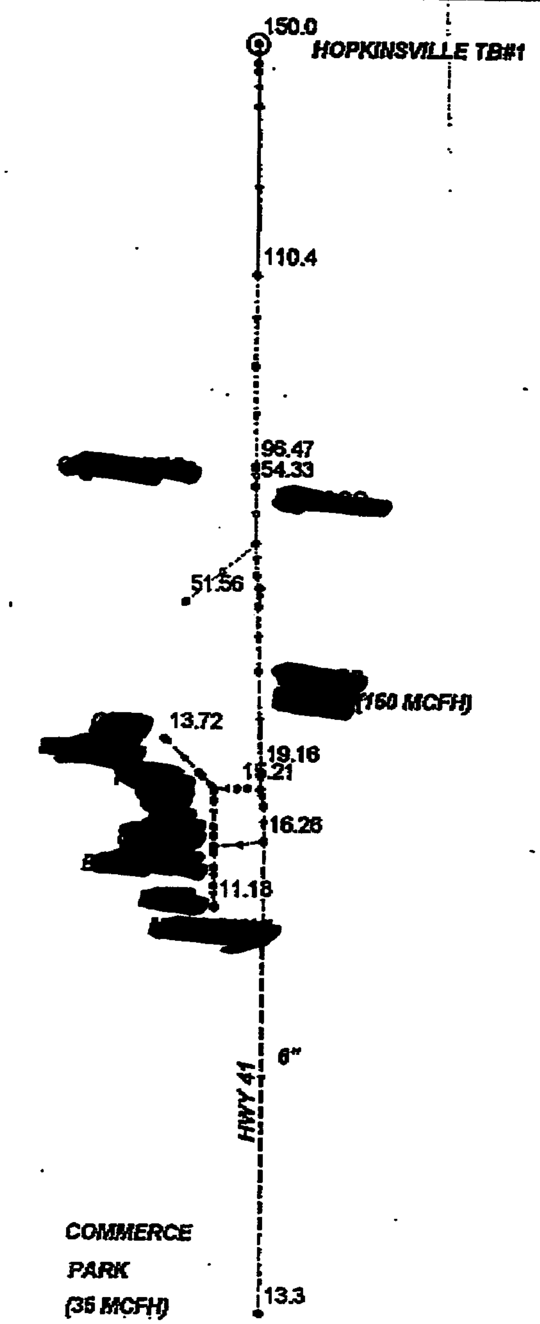
STUDY #4: THIS STUDY WAS RUN UNDER THE SAME CONDITIONS AS STUDY #3 ONLY [redacted] FLOW RATE IS 0 MCFH, REFLECTING FUTURE CONDITIONS. THE GAS AVAILABLE TO COMMERCE PARK WILL BE ABOUT 190 MCFH AT A PRESSURE OF APPROXIMATELY 15 PSI.

CONCLUSIONS AND RECOMMENDATIONS: WITHOUT REMOVING THE CALVIN DRIVE REGULATOR STATION AND UPRATING THE EXISTING PIPING AND FACILITIES, THE HIGHEST FLOW RATE THAT CAN BE ACHIEVED IN THE COMMERCE PARK AREA WOULD BE ABOUT 85 MCFH. THIS RATE WOULD OF COURSE BE CONTINGENT ON [redacted] FLOW RATE. LOADS IN THE COMMERCE PARK AREA ARE EXPECTED TO EXCEED 85 MCFH. PROJECTED FLOW REQUIREMENTS ARE NOW NEARING 180 MCFH. THIS SYSTEM IMPROVEMENT OF UPRATING THE EXISTING WKG FACILITIES FROM 60 PSI TO 150 PSI WILL BE NECESSARY TO COMPLETELY SUPPLY THE ANTICIPATED LOADS IN THE COMMERCE PARK AREA.

BJB 04/04/97

STUDY

HOPKINSVILLE COMMERCE PARK HWY 41
EXISITNG CONDITIONS - PHELPS DODGE FLOW IS 150 MCFH



HOPIND
PRESSURE
(PSIG)

---RANGE---		COUNT
BELOW	38.9	24
38.9	66.7	6
66.7	94.5	1
94.5	122.2	2
ABOVE	122.2	4

MIN = 11.13
MAX = 150.00
NODE ANN:PRES
ELEM ANN:OFF

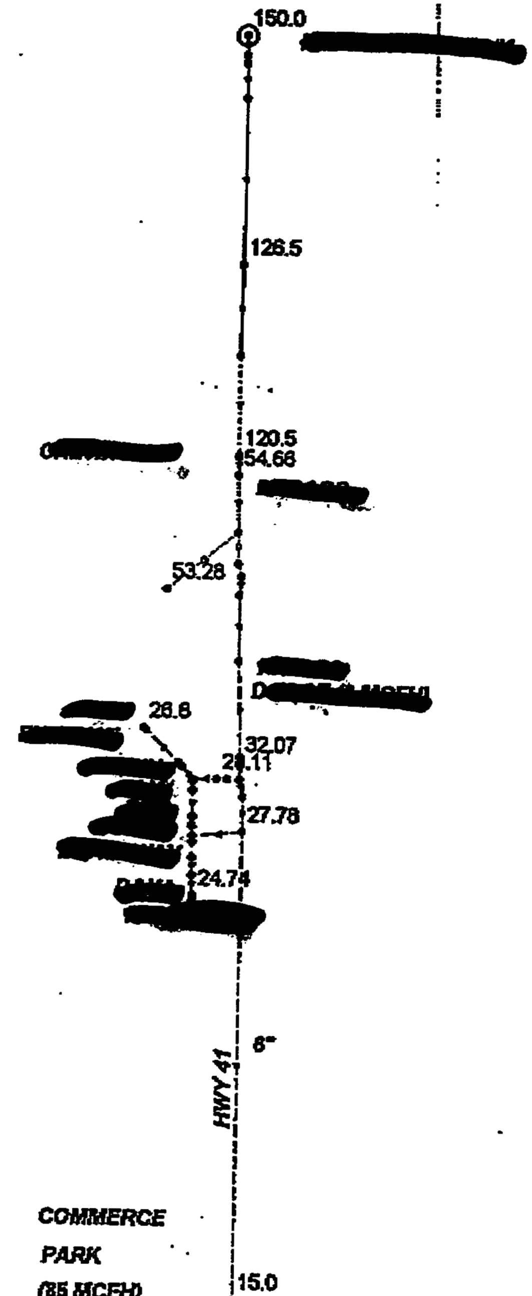
State: BALANCED

Apr 02, 1997

Corners: (FEET)
UL:(-27995,3128)
LL:(-27995,-38995)
UR:(30324,3128)
LR:(30324,-38995)

STUDY

HOPKINSVILLE COMMERCE PARK HWY 41
FUTURE CONDITIONS - PHELPS DODGE FLOW IS 0 MCFH



HOPIND
PRESSURE
(PSIG)

---RANGE---		COUNT
BELOW	42.0	23
42.0	69.0	7
69.0	96.0	1
96.0	123.0	1
ABOVE	123.0	5

MIN = 15.00
MAX = 150.00
NODE ANN:PRES
ELEM ANN:OFF

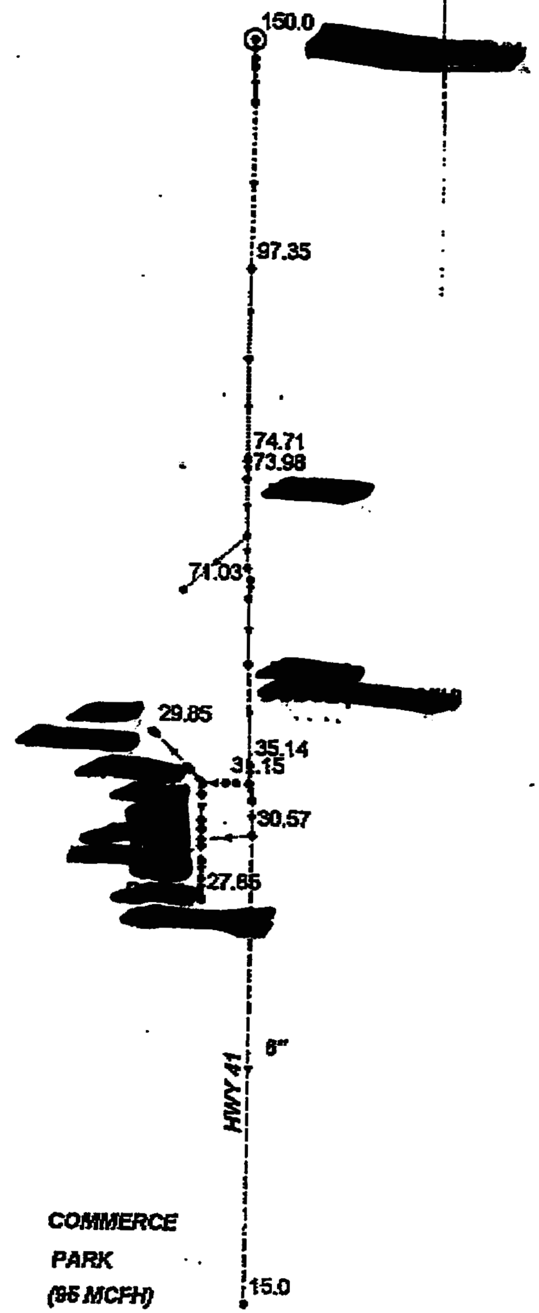
State: BALANCED

Apr 02, 1997

Corners: (FEET)
UL:(-27995,3128)
LL:(-27995,-38995)
UR:(30324,3128)
LR:(30324,-38995)

STUL

HOPKINSVILLE COMMERCE PARK HWY 41
REMOVE CALVIN DR. REGULATOR STA. & UPRATE



HOPIND2
PRESSURE
(PSIG)

---RANGE----		COUNT
BELOW	42.0	23
42.0	69.0	3
69.0	96.0	7
96.0	123.0	1
ABOVE	123.0	3

MIN = 15.00
MAX = 150.00
NODE ANN:PRES
ELEM ANN:OFF

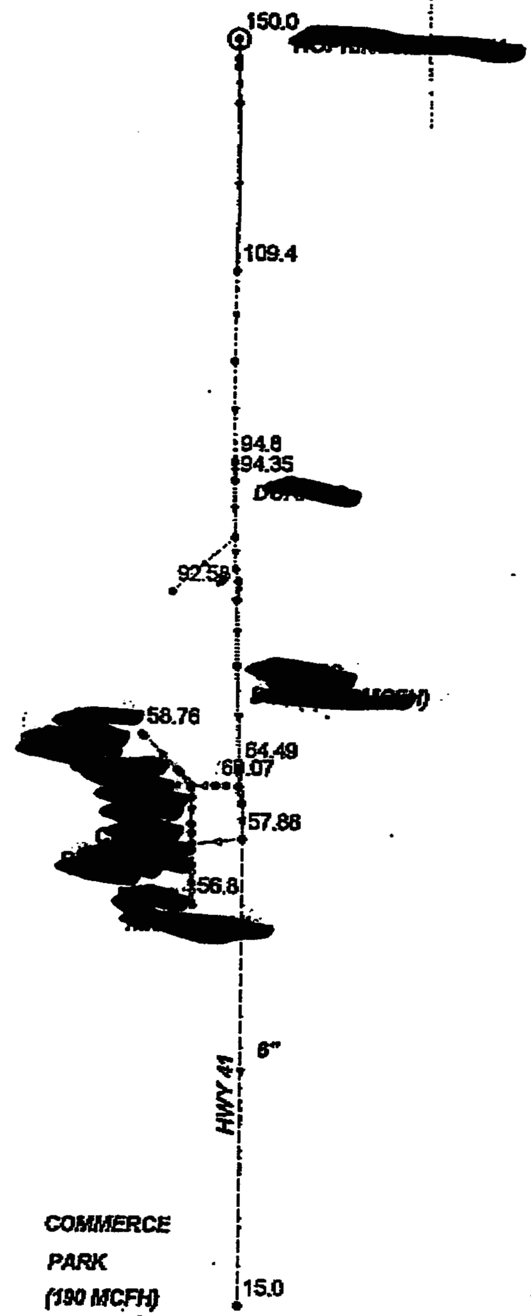
State: BALANCED

Apr 02, 1997

Corners: (FEET)
UL:(-27995,3128)
LL:(-27995,-38995)
UR:(30324,3128)
LR:(30324,-38995)

STUDY

HOPKINSVILLE COMMERCE PARK HWY 41
REMOVE CALVIN DR. REGULATOR STA. & UPRATE



HOPIND2
PRESSURE
(PSIG)

---RANGE---		COUNT
BELOW	42.0	1
42.0	69.0	21
69.0	96.0	9
96.0	123.0	2
ABOVE	123.0	4

MIN = 15.00
MAX = 150.00
NODE ANN:PRES
ELEM ANN:OFF

State: BALANCED

Apr 02, 1997

Corners: (FEET)
UL:(-27995,3128)
LL:(-27995,-38995)
UR:(30324,3128)
LR:(30324,-38995)

10/08/98 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300

ENTRY: 10/08/98 STATUS: E

FISCAL YEAR: 1999 TYPE: N

NUMBER: 216906-003 560 - WALNUT RIDGE 4" & 2" EXTENSION

OP/SUB CO: 40 WESTERN KENTUCKY GAS

RATE/DIV: 9 WESTERN KENTUCKY GAS

RESP CTR: 5602700 BOWLING GREEN OPERATIONS

PROP LOC: 560 BOWLING GREEN

LINE NO.: 9560-411 ADDRESS: BOWLING GREEN

CONTRACT: DEFERRED/DEPOSIT

START DATE: 10/15/1998 COMPLETE DATE: 11/15/1998

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A		37602	10	514,999	0	85,224	429,775	67,883
	6249'-4"/9260'-2" - WALNUT RDG.							
	6249 FT. OF 4" .395 SDR-11.5 2406 PIPE							8,999
	9260 FT. OF 2" .216 SDR-11 2406 PIPE							3,889
	STORES EXPENSE 45%							5,800
	OTHER MATERIAL							1,100
	STORES EXPENSE 45%							495
	SUPPLIES AND EXPENSES							3,500
	COMPANY LABOR							250
	CONTRACT LABOR							43,850

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 67,883

DESCRIPTION:

EXTENSION WILL SERVE 42 NEW BUILDING LOTS IN WALNUT RIDGE SUBDIVISION.
DEFER/DEPOSIT AGREEMENT WITH WALNUT RIDGE INC. [redacted]
DEPOSIT OF $73,303.00. 30 LOTS DEFERRED.
START AT INTERSECTION OF DILLARD RD. AND NEAL HOWELL RD. WITH 4" PE.
AT INTERSECTION OF THREE SPRINGS AND LONG ROAD, CONVERT TO 2" PE.
6150' OF 2" ADJACENT TO LONG ROAD, AND CONVERT BACK TO 4" ALONG
MATLOCK PIKE. FUTURE DEVELOPMENT ON HERMAN AVE INDICATES TIE-IN AT
THREE SPRINGS ROAD AND MATLOCK PIKE. FUTURE DEVELOPMENT ON LONG ROAD
NOT PROBABLE.
MAIN INSTALLATION ON NEAL HOWELL, MATLOCK PIKE, AND SUBDIVISION ON
PUBLIC UTILITY EASEMENT. LONG ROAD ON PRIVATE EASEMENT.
AVERAGE ROE FIRST 5 YEARS IS 6.1%.
PAPERWORK EN-ROUTE TO TECHNICAL SERVICES.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O

TAX AUTHORITY: 93605 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	DOUGLAS E STEARNS		
S T	WILLIAM B OOST	10/8/98	16:29

PLEASE REVIEW.

DISTRIBUTION: OOST AKERS CROWE SHUDSON HARMON TOWEN

INSTRUCTIONS:

12/09/98 CAPITAL APPROPRIATION GENERATION SYSTEM CAG300
ENTRY: 10/08/98 AFE HAS RCVD FINAL APPRVL BY: ROBERT EARL FISCHER STATUS: A
FISCAL YEAR: 1999 TYPE: N

NUMBER: 216906-003 560 - WALNUT RIDGE 4" & 2" EXTENSION
OP/SUB CO: 40 WESTERN KENTUCKY GAS
RATE/DIV: 9 WESTERN KENTUCKY GAS
RESP CTR: 5602700 BOWLING GREEN OPERATIONS
PROP LOC: 560 BOWLING GREEN
LINE NO.: 9560-411 ADDRESS: BOWLING GREEN

CONTRACT: DEFERRED/DEPOSIT
START DATE: 10/15/1998 COMPLETE DATE: 11/15/1998

L S	APPROP NUMBER	BUDGET NO	I S	BUDGET REQUEST AMOUNT	FUNDS COMMITTED AMOUNT	BUD REQUEST PEND AFE(S) AMOUNT	BUD REQUEST BALANCE AMOUNT	AFE LINE ITEM AMOUNT
A	918766	37602	10	514,999	139,803	51,662	323,534	67,883
	6249'-4"/9260'-2" - WALNUT RDG.							
	6249 FT. OF 4" .395 SDR-11.5 2406 PIPE							8,999
	9260 FT. OF 2" .216 SDR-11 2406 PIPE							3,889
	STORES EXPENSE 45%							5,800
	OTHER MATERIAL							1,100
	STORES EXPENSE 45%							495
	SUPPLIES AND EXPENSES							3,500
	COMPANY LABOR							250
	CONTRACT LABOR							43,850
A	918767	37602	82	0	55,723-	0	55,723	55,723-
	AID-IN-CONSTRUCTION							
	AID-IN-CONSTRUCTION FOR THIS PROJECT							55,723-

RED APPROVAL AMT: 0 NORMAL APPROVAL AMT: 12,160

DESCRIPTION:
EXTENSION WILL SERVE 42 NEW BUILDING LOTS IN WALNUT RIDGE SUBDIVISION.
DEFER/DEPOSIT AGREEMENT WITH WALNUT RIDGE INC. [redacted]
DEPOSIT OF $73,303.00. 30 LOTS DEFERRED.
START AT INTERSECTION OF DILLARD RD. AND NEAL HOWELL RD. WITH 4" PE.
AT INTERSECTION OF THREE SPRINGS AND LONG ROAD, CONVERT TO 2" PE.
6150' OF 2" ADJACENT TO LONG ROAD, AND CONVERT BACK TO 4" ALONG MATLOCK PIKE. FUTURE DEVELOPMENT ON HERMAN AVE INDICATES TIE-IN AT THREE SPRINGS ROAD AND MATLOCK PIKE. FUTURE DEVELOPMENT ON LONG ROAD NOT PROBABLE.
MAIN INSTALLATION ON NEAL HOWELL, MATLOCK PIKE, AND SUBDIVISION ON PUBLIC UTILITY EASEMENT. LONG ROAD ON PRIVATE EASEMENT.
AVERAGE ROE FIRST 5 YEARS IS 8.6%. THE IRR IS 15.4 %.
PAPERWORK EN-ROUTE TO TECHNICAL SERVICES.

MAP REFERENCE: INSIDE/OUTSIDE CITY LIMITS: O
T AUTHORITY: 93605 COM SCH

STATUS	NAME	DATE	TIME
CURRENT USER:	ROBERT EARL FISCHER		
APPROVED	ROBERT EARL FISCHER	12/9/98	11:59

APPROVED JOHN KEVIN AKERS 12/2/98 11:33

I RECOMMEND APPROVAL OF THIS PROJECT. WE HAVE REQUESTS FOR 12 YARDLINES FROM CONVERSION CUSTOMERS PENDING APPROVAL OF THIS PROJECT.

T DAVID H DOGGETTE 12/2/98 11:18

APM CRITERIA APPEARS GOOD. I RECOMMEND APPROVAL.

SENT JOHN KEVIN AKERS 12/1/98 10:06

PLEASE REVIEW AND COMMENT.

PULLBACK JOHN KEVIN AKERS 12/1/98 09:02

PULLED BACK TO COMMENT.

APPROVED JOHN KEVIN AKERS 11/20/98 15:52

PROJECT APPROVED.

PULLBACK JOHN KEVIN AKERS 11/20/98 15:43

PULLED BACK TO SHOW AID-IN-CONSTRUCTION.

SENT JOHN KEVIN AKERS 11/11/98 14:50

DAVE, PLEASE REVIEW THE PROJECT ECONOMICS FOR THIS AFE AND COMMENT. I HAVE SENT THE APM TO YOU VIA OUTLOOK. I HAVE INCLUDED IN THE ANALYSIS ALL SERVICE COST AND YARDLINE PROFIT.

SENT JERRY W HARMON 10/26/98 10:55

EXISTING AGREEMENT CAN NOT SHOW NON-REFUNDABLE AMOUNT OF $55,723 WHICH IS AMOUNT CALCULATED FOR AID IN CONSTRUCTION ON PROJECT.

SENT JOHN KEVIN AKERS 10/26/98 09:13

PLEASE INDICATE THE DOLLAR AMOUNT THAT WILL OR MAY NOT BE REFUNDED.

SENT JERRY W HARMON 10/23/98 08:01

PROJECT WAS THROUGHLY RESEARCHED BY JOINT EFFORTS OF SALES AND OPERATIONS PERSONNEL. WITH THE COLLECTION OF COMPLETE CONSTRUCTION COST, ($73,303.00). LITTLE CHANCE OF DEVELOPMENT REFUNDS ALONG THE LONG ROAD AREA. A VERY RAPID GROWTH OF LARGE HOMES, (AROUND 3,000 SQ. FT. THE NORM), IN THE MATLOCK PIKE, NEAL HOWELL RD., HERMAN LANE AND ELROD ROAD AREAS ALONG WITH THE ADDED ADVANAGE OF INCREASING SYSTEM TIE-BACK CAPABILITIES TO THE GROWING AREA, MAKES THIS A SOUND PROJECT. LOCAL MANAGEMENT FEELS THAT ALTHOUGH THE INITIAL ROE, (6.1%), IS LOWER THAN RECOMMENDED, WITHIN A VERY SHORT PERIOD THIS WILL BE A VERY PROFITABLE PROJECT FOR WKG. RECOMMEND APPROVAL

SENT RONALD BENNINGFIELD 10/22/98 12:27

THIS IS AREA OF HIGH GROWTH. RECOMMEND APPROVAL.

SENT WILLIAM B OOST 10/22/98 07:22

PLEASE REVEW.

SENT PAUL W VANCE 10/21/98 15:34

I RECOMMEND APPROVAL WITH THE UPFRONT DOLLARS.

SENT WILLIAM B OOST 10/21/98 11:28

PLEASE REVIEW.

SENT DAVID H DOGGETTE 10/21/98 11:09

TECHNICAL REVIEW IS COMPLETE. HOWEVER, BASED ON THE ROE CITED IN THE COMMENTS, YOU SHOULD DISCUSS THIS WITH YOUR LOCAL SUPERVISORS AS TO HOW, OR IF, WE SHOULD PROCEED WITH THIS PROJECT.

SENT DOUGLAS E STEARNS 10/13/98 14:45

RECOMMEND APPROVAL.THIS PROJECT CONFORMS TO THE LONG RANGE PLAN FOR SYSTEM DEVELOPMENT IN SW BOWLING GREEN. THERE IS A TB STATION AT ELROD RD AND THE PARKWAY THAT IS NOT YET TIED TO THIS DISTRIBUTION SYSTEM SOUTHWEST OF THE PARKWAY, BUT AS DEVELOPMENT CONTINUES, WILL BE TIED. $'S HAVE BEEN COLLECTED THAT ARE NOT EXPECTED TO BE REFUNDED.

SENT WILLIAM B OOST 10/8/98 16:29

PLEASE REVIEW.

.TRIBUTION: OOST AKERS CROWE SHUDSON HARMON TOWEN

INSTRUCTIONS:

THIS AFE HAS RECEIVED FINAL APPROVAL BY ROBERT EARL FISCHER .

THIS AFE FORM HAS BEEN SENT TO EACH PERSON ON THE DISTRIBUTION LIST.

Sent to:	AKERS	- AKERS, KEVIN	(to)
	OOST	- OOST, WILLIAM B.	(to)
	CROWE	- CROWE, JANICE	(to)
	SHUDSON	- HUDSON, SIDNEY WAYNE	(to)
	HARMON	- HARMON, JERRY	(to)
	TOWEN	- OWEN, TIM	(to)
	KDOBBS	- DOBBS, KEVIN	(to)
	BENNINGF	- BENNINGFIELD, RONNIE	(to)
	BWOODWAR	- WOODWARD, BILL	(to)
	PRICE	- PRICE, DANIEL K.	(to)

WKG 305 R-5-90

216906-003

COMPANY Western Kentucky Gas Co.
TO:
TITLE:

APPROPRIATION REQUEST

FILE NUMBER

GENERAL
TITLE OF PROJECT Walnut Ridge Subdivision - 4"/2" Ext.
SUBMITTED BY
CONTRACT (S) LINE NO.
CONFIRMING (Y/N) LINE NAME
RATE DIV LOCATION NO.
WORK TO BE: STARTED / / COMPLETED / /

BUDGET
CENTER
BALANCE
DATE / /
BY

APPRO.- ACCOUNT NUMBER	ITEM STATUS	QUANTITY/ DESCRIPTION	COST/ CREDITS
37602		4" PE Pipe $1.44 @ ft (6249')	8999
		2" PE Pipe .42 @ ft (9260)	3889
			5800
		Stores 45%	
			1100
		Other Material	495
		Stores 45%	3500
		Supplies & Expenses	250
		Co Labor	13850
		Contract Labor	
			67883
			23080
		WKG 34%	12898
		Corp 19%	

$90,963 Less Corp overhead $5.86 @ FT $73,303 TOTAL 103,861

COMMENTS
DeFee 30 Total Footage 15509' - 12509' Deposit $73,303

BUDGET CONTROL NO.
PARISH/COUNTY SCHOOL DISTRICT
RANGE SECTION WARD TOWNSHIP ICL/OCL

OPERATING COMPANY — CORPORATE
RECOMMENDED: DATE DATE
OPERATIONS / / / /
TECH SERVICE / / / /
MARKETING / / / /
/ / / /
/ / / /
APPROVED
/ / / /

COPIES: PAGE OF

216406-003

Profitability Model

Project Summary

Project Name:	WALNUT RIDGE - BOWLING GREEN
AFE # :	0
Company and State:	WKG, Kentucky
Prepared By:	BYRON OOST
Date:	1/1/04

ATMOS
Version 3.5

Total Capital Costs	**$108,014**	
Total AIC	**$55,723**	
Total Capital Outlay	**$52,291**	
Total Marketing Programs	**$0**	
Total Project Cost	**$52,291**	
Total Refundable Advance	**$20,510**	
Economic Life of Project	30	Years
Depreciated	**30 Years (3.3%)**	

Economic Indicators

Internal Rate of Return	**16.37**	%
Net Present Value	**$26,473**	
Payback:	**11**	Years
	2	Months
Average ROE for First 5 Years:	**6.1**	%

216906-00

Profitability Model - Detailed Summary

Project: WALNUT RIDGE - BOWLING GREEN **AFE # :** 0

Year	Capital Outlay	Operating Costs	Marketing Programs Cost	Refunds of Advance	Interest Expense	Ad Valorem Tax	Income Taxes	After Tax Net Income	Cash Flow	Total Load (ccf)	Return On Equity (%)
1	$52,291.03	$60.00	$0.00	$0.00	$1,830.19	$50.55	($20.87)	($34.05)	($48,026.68)	1680	-0.08%
2	$0.00	$100.00	$0.00	$0.00	$1,810.81	$48.80	$605.49	$987.91	$7,778.71	2800	2.48%
3	$0.00	$150.00	$0.00	$0.00	$1,790.08	$47.06	$1,386.95	$2,262.92	$8,643.06	4200	6.37%
4	$0.00	$175.00	$0.00	$2,930.00	$1,767.90	$45.32	$1,782.50	$2,908.30	$5,987.36	4900	9.20%
5	$0.00	$200.00	$0.00	$2,930.00	$1,744.16	$43.58	$2,117.41	$3,454.72	$6,194.00	5600	12.[illegible]%
6	$0.00	$225.00	$0.00	$2,930.00	$1,718.76	$41.83	$2,452.94	$4,002.17	$6,428.74	6300	16.14%
7	$0.00	$250.00	$0.00	$2,930.00	$1,691.59	$40.09	$2,789.16	$4,550.73	$6,814.68	7000	20.97%
8	$0.00	$275.00	$0.00	$2,930.00	$1,662.51	$38.35	$3,126.09	$5,100.46	$7,335.33	7700	27.35%
9	$0.00	$300.00	$0.00	$2,930.00	$1,631.40	$36.60	$3,463.80	$5,651.46	$7,859.32	8400	36.19%
10	$0.00	$325.00	$0.00	$2,930.00	$1,598.11	$34.86	$3,802.33	$6,203.81	$8,374.28	9100	49.14%
11	$0.00	$325.00	$0.00	$0.00	$1,562.49	$33.12	$3,755.30	$6,127.06	$11,196.01	9100	63.41%
12	$0.00	$325.00	$0.00	$0.00	$1,524.38	$31.37	$3,770.44	$6,151.77	$11,178.51	9100	91.24%
13	$0.00	$325.00	$0.00	$0.00	$1,483.60	$29.63	$3,786.60	$6,178.14	$11,168.19	9100	160.10%
14	$0.00	$325.00	$0.00	$0.00	$1,439.96	$27.89	$3,803.84	$6,206.27	$11,148.59	9100	606.27%
15	$0.00	$325.00	$0.00	$0.00	$1,393.27	$26.15	$3,822.25	$6,236.30	$11,136.03	9100	-352.52%
16	$0.00	$325.00	$0.00	$0.00	$1,343.31	$24.40	$3,841.90	$6,268.36	$9,903.19	9100	-190.13%
17	$0.00	$325.00	$0.00	$0.00	$1,289.85	$22.66	$3,862.87	$6,302.58	$8,673.12	9100	-177.01%
18	$0.00	$325.00	$0.00	$0.00	$1,232.65	$20.92	$3,885.27	$6,339.13	$8,652.46	9100	-168.29%
19	$0.00	$325.00	$0.00	$0.00	$1,171.45	$19.17	$3,909.19	$6,378.15	$8,630.28	9100	-163.04%
20	$0.00	$325.00	$0.00	$0.00	$1,105.97	$17.43	$3,934.74	$6,419.83	$8,606.48	9100	-160[illegible]%
21	$0.00	$325.00	$0.00	$0.00	$1,035.89	$15.69	$3,962.03	$6,464.36	$8,580.93	9100	-161.56%
22	$0.00	$325.00	$0.00	$0.00	$960.92	$13.94	$3,991.18	$6,511.92	$8,553.52	9100	-165.45%
23	$0.00	$325.00	$0.00	$0.00	$880.70	$12.20	$4,022.33	$6,562.74	$8,524.12	9100	-173.14%
24	$0.00	$325.00	$0.00	$0.00	$794.86	$10.46	$4,055.61	$6,617.04	$8,492.58	9100	-185.93%
25	$0.00	$325.00	$0.00	$0.00	$703.01	$8.72	$4,091.17	$6,675.07	$8,458.76	9100	-206.30%
26	$0.00	$325.00	$0.00	$0.00	$604.73	$6.97	$4,129.18	$6,737.08	$8,422.49	9100	-239.41%
27	$0.00	$325.00	$0.00	$0.00	$499.57	$5.23	$4,169.80	$6,803.36	$8,383.62	9100	-297.44%
28	$0.00	$325.00	$0.00	$0.00	$387.06	$3.49	$4,213.22	$6,874.20	$8,341.94	9100	-417.10%
29	$0.00	$325.00	$0.00	$0.00	$266.66	$1.74	$4,259.63	$6,949.93	$8,297.27	9100	-782.25%
30	$0.00	$325.00	$0.00	$0.00	$137.84	$0.00	$4,309.25	$7,030.88	$8,249.40	9100	#DIV/0!

CONSTRUCTION PROJECT DESIGN OVERVIEW

Date ______ District Bowling Green Town Name Bowling Green

Project Name Walnut Ridge Subdivision

Prepared By Byron Oost Job No. ______

Parameters:	Existing/ Retired	Proposed	Proposed Future
* M.A.O.P. (psig - oz)	60	60	
* System Winter Op. Press.	55	55	
* System Summer Op. Press.	35	35	
* Min. System Press. in Area of Extension			
* Load (MCFH)			
* Main Line Length (ft.)		9200'/6249'	
* Main Line Diameter	4"	2"/4"	
* Pipe Type	PE	PE	
Outlet Pressure (psig - oz)			
Service Line Length (ft.)			
Service Pressure			
Measurement Pressure			
Major Gas Appliances/Load			

Any extension, retirement, relocation or replacement involving steel pipe (FWO and/or Leak Repair) must be approved by Corrosion Technician with the following information: C. P. Town No. ___ Section No. _____ C. P. Class of Steel Main Retired Bare not C. P. ____ Bare C. P. ____ Coated C. P. ____

Comments Extension will serve Walnut Ridge Subdivision

Approval Recommended:

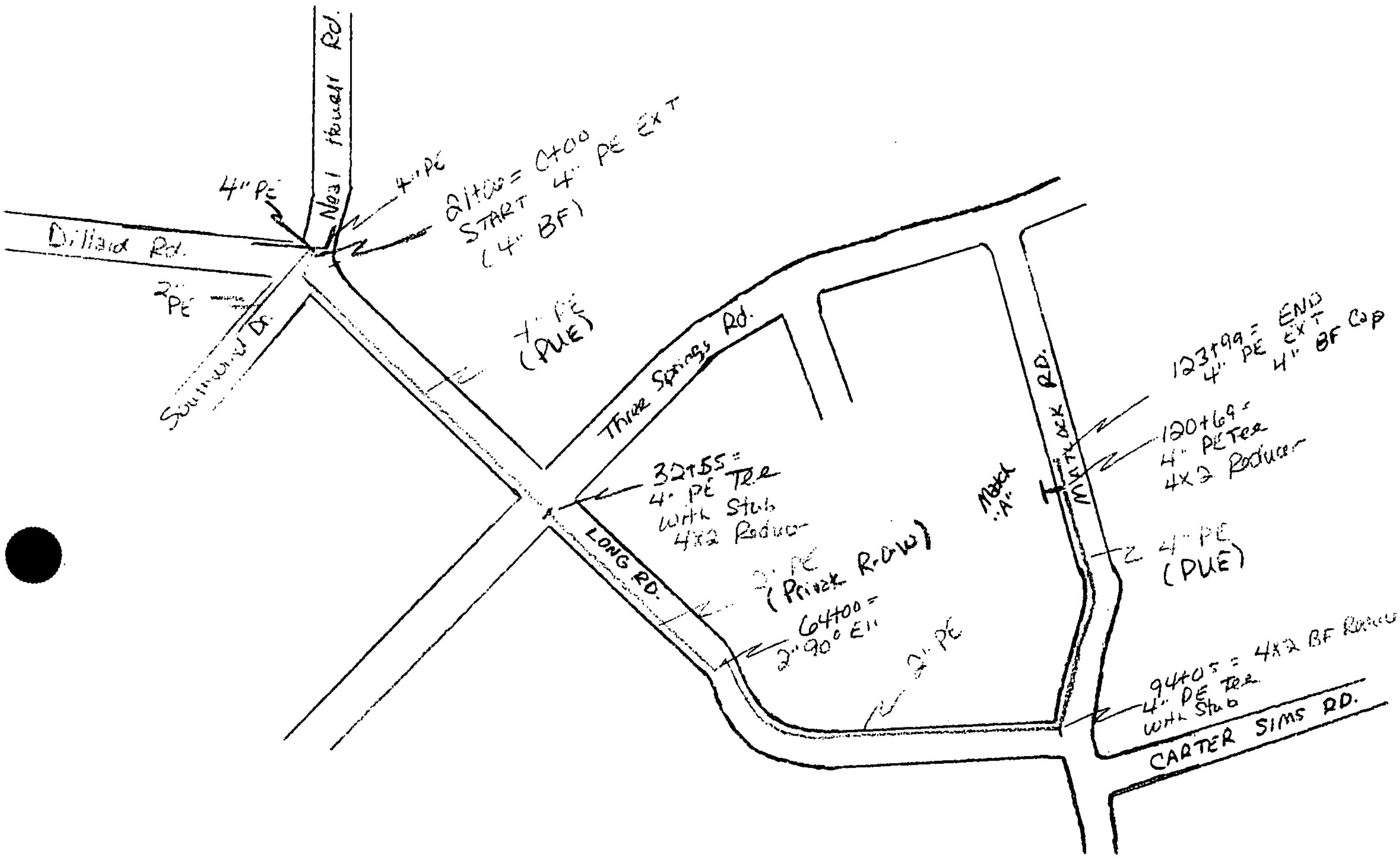
Corrosion Technician: ______

DBStea

Include As Appropriate: Area Maps, Location Maps/Sketches, Plats, Gas Flow Analysis Data (on 3 1/2" Disk), Leak History and/Or Economic Analysis

c:\123\data\desovr.wk1 Rev: 3/15/93

BY B Loss DATE 4-4-98 SUBJECT 560- Walnut Ridge SHEET NO. 1 OF 2
CHKD. BY ____ DATE ____ 4" PE - Approach Main JOB NO. ____
R/W ____ PUBLIC ☐ PRIVATE ☑ (PUE) TOWN Bowling Green PLATE NO. SW-30



WK-414, R-11-89

DEFERRED PAYMENT — MAIN EXTENSION AND DEPOSIT AGREEMENT

C.O. Number ____________
Completion Date ____________

THIS AGREEMENT, made and entered into this ____ day of September, 1998, by and between WESTERN KENTUCKY GAS COMPANY, a division of Atmos Energy Corporation, of Owensboro, Kentucky, hereinafter designated as the COMPANY, and Walnut Ridge Inc.- 927 Broadway Ave. of Bowling Green, Kentucky, hereinafter designated as the DEVELOPER;

WITNESSETH:

WHEREAS the Company is a gas utility engaged in the distribution and sale of natural gas but does not have presently installed a gas main within the Developer's Proposed Real Estate Subdivision and the required investment for the necessary main and facilities would be an unprofitable investment; and

The Developer is developing said real estate subdivision, hereinafter referred to as 'subdivision', and desires to obtain gas service to serve each residential lot in the subdivision; and

The Developer recognizes that the requested gas main will necessitate a capital investment either on the part of the Developer by way of a refundable Main Extension Deposit and/or on the part of the Company; and

The Developer wishes the Company to make the capital investment required, or a substantial part thereof, for the requested gas main extension of adequate size and capacity, in lieu of, in whole or in part, the Main Extension Deposit; and

In evaluating Developer's request, the Company has determined that there will not be a sufficient number of customers to be served by said main extension to yield the Company a fair rate of return upon the capital investment required to make such extension, unless all houses or dwelling units in the subdivision to be served by the extension utilize, as a minimum, gas water heating and gas central comfort heating appliances, and

In order to obtain gas service in the subdivision, the Company and the Developer mutually agree to defer the Main Extension Deposit, or a substantial part thereof, for a period of three (3) years after completion of said main extension, so that gas service will be made available to each lot in the subdivision and the adjacent premises.

NOW, THEREFORE, in consideration of the promises, one to the other hereinafter contained, the Company and the Developer covenant and agree as follows, subject to the Rules and Regulations of the Company and those of the Public Service Commission of Kentucky:

(1) The Company will install approximately 15,509 feet of 4 -inch and 2 -inch gas main at an estimated cost of $5.86 per foot, totaling $90,883.00 and consisting of:

A. 12,399 feet of 4 -inch and 2 -inch "approach main" extending from the presently existing main on Dillard Rd. / Neal Howell Rd. to a point on or adjacent to Developer's subdivision in Warren County, Kentucky, and

B. 3110 feet of 2 -inch and ____ -inch "distribution main" to serve each lot in the subdivision, or portion thereof, being described as located at: Walnut Ridge Subdivision located on Matlock Pike Rd.

The "approach main" to the subdivision and the "distribution main" within the subdivision, hereinafter are both sometimes referred to as 'main'.

The Company shall commence and pursue to completion, the construction of this main within a reasonable period of time consistent with the orderly development of the subdivision. If the main extension is to be performed in phases at the option of the Company, the term 'completion of construction' shall mean that date, after which, the initial phase of the main extension is complete and ready for customers to be connected ('connected' hereinafter shall mean connected for permanent gas service on a main extended under terms of this Agreement).

(2) The Company will permit the deferred payment of a deposit, or a substantial part thereof, by the Developer for a period of three (3) years following the 'completion of construction' of said main extension, an amount in the sum of $17,580.00 representing the estimated cost for 3000 feet of main @ $5.86 per foot, based on a footage allowance of 100 feet of main per customer to serve 30 customers. This latter figure being the number of customers who may reasonably be expected to contract for permanent gas service on the "distribution main" extension within the subdivision over the succeeding three (3) year period, a number mutually agreed upon by the Company and the Developer.

If, at the end of the three year period, the number of customers connected is insufficient to justify the total of 3000 feet allowed, the Developer will be required to deposit with the Company an amount in the sum of $5.86 per foot of main times the number of feet deficient. This footage allowance will be made in accordance with those provisions of Paragraph (5) hereof, for only those residential and/or commercial customers connected on the "approach main" or, if connected on the "distribution main", those utilizing, as a minimum, gas water heating and gas central comfort heating appliances.

This deferred deposit, if necessary, will be due and payable to the Company within 30 days after the Developer has been notified by registered mail that there remains a deficiency in the required number of customers and/or the corresponding footage allowed therefor at the end of the three year period, bearing interest at the rate of twelve percent (12%) per annum from the date due. Upon receiving payment of the deferred deposit, the Company and the Developer will also enter into a Letter Agreement amending the refund provisions of Paragraph (5) of this Agreement; however, maintaining the original ten-year (10) term. However, if this main extension has been performed in phases, the Developer will not be required to deposit monies for those phases of the main extension not complete or under construction by the Company.

(3) In addition, the Company will also permit additional footage allowances for the following customers who have made application for permanent gas service:

A. ____________ feet, based on an allowance of one hundred feet of main per customer for ________ customer(s), and

B. ____________ feet, based on an allowance, for commercial customers only, of one foot of main for each cubic foot per hour (chf) of rated input to a base load appliance(s) greater than 200 cfh, for ________ customer(s), but which shall not exceed 900 feet of main allowed per customer so qualifying.

It being understood and agreed that no interest shall be due or payable at any time on this deposit. Developer will also secure at his expense any necessary rights of way or permits, and same shall be procured in the name of the Company and on the Company's standard form where same applies.

(4) When the length of new main to serve the subdivision exceeds the total footage of 3,000 feet allowed in Paragraphs (2) and (3A,B) above, the Developer will deposit with the Company herewith the sum of $73,303.00 representing its equitable share of the estimated cost of the remaining 12,509 feet of main @ $5.86 per foot for excess footage not covered by these allowances.

(5) The Company agrees to refund to the Developer for a period of ten (10) years after 'completion of construction' of said main the sum $ 586.00 for each additional customer connected. Also, for each additional commercial customer connected who has in service a base load appliance(s) the rated input to which is greater than 200 cfh, the Company agrees to refund to the Subscriber the cost of one foot of main or the sum of $ 5.86 for each cubic foot per hour of rated input to such base load appliance(s) greater than 200 cfh; however, this refund shall not exceed the cost of 900 feet of main allowed per customer so qualifying.

No refund shall be made for:

A. Any residential and/or commercial customer(s) connected and included in the footage allowance(s) in Paragraphs (2) and (3) above, totaling 3,000 feet, for whom a deposit has not been made, or

B. Any customer connected within said subdivision on the "distribution main" who does not utilize, as a minimum, gas water heating and gas central comfort heating appliances, or

C. Any customer for whom the Company installs a lateral main or additional extension.

However, the Company shall have the right to make any additional extension or lateral it so desires, and provided further, that in no event shall the refunds to the Developer exceed the total amount deposited by it under the terms of this Agreement.

If an order limiting the sale of gas to residential and/or commercial customers be promulgated by the Public Service Commission of Kentucky then the above refund Paragraph shall be held in abeyance until the extension of residential and/or commercial service is again authorized by Public Service Commission order, and no refund will be made while the Limitation Order is in effect.

(6) For additional main extensions in the subdivision in the future the Company will allow customer connections in excess of those needed to satisfy the terms and conditions of any Subsequent "Deferred Payment - Main Extension and Deposit Agreement" to apply toward refund of any deposit outstanding from a particular Original Agreement, provided the option in Paragraph (10) hereof is exercised and the following conditions are satisfied:

A. The Developer of any such Subsequent Agreement and the Original Agreement are one and the same party (affiliates may be considered the same party for purposes of this provision), and

B. The additional main extension in said subdivision is directly connected to a main which was previously extended under terms of a previous Agreement by the same Developer, and

C. The term of the Original Agreement will not be extended, remaining at ten (10) years.

(7) The Developer agrees that full and complete title and ownership to the gas main constructed under this agreement shall be vested entirely in and with the Company, and the Developer shall have no further claim upon said main except as herein provided, it being agreed that the Company will utilize said main as a part of its gas distribution system and shall be responsible for the operation and maintenance of same at all times.

(8) The provisions of this Agreement shall be binding upon and inure to the benefit of the successors and assigns of the Company and the Developer.

(9) This Agreement may be modified, amended, rescinded, or terminated only by a writing signed by the Company and the Developer or their duly authorized agents.

(10) This Agreement is the (Original/Subsequent)* Agreement applying to said subdivision. If a Subsequent Agreement, the Original Agreement, Construction Order Number ______________, was signed and dated ________________, 19____.

*Strike the inappropriate provision, at the option of the Developer if there exists an Original Agreement.

(11) In the event the Company is required to file suit against the Developer to enforce any provision of this Agreement, the Developer agrees to reimburse the Company for its expenses incurred in connection with such suit, including court costs and reasonable attorney's fees.

(12) This Agreement shall not become effective or binding on either party until approved and accepted by an authorized officer of the Company at its General Office in Owensboro, Kentucky.

(13) This Agreement is applicable in the entire service area of the Company.

(14) This Agreement is as authorized by rule of the Public Service Commission of Kentucky under 807 KAR 5:022, Section 9, Paragraph 16. "Extension of Service".

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in duplicate the date and year first herein above written.

WESTERN KENTUCKY GAS COMPANY
a division of Atmos Energy Corporation

WITNESS [illegible] .... By: Walnut Ridge [illegible] .... COMPANY

....

WITNESS .... By: [redacted] DEVELOPER

216906 - 003

1008

WALNUT RIDGE, INC.
729 MATLOCK RD.
BOWLING GREEN, KY 42104

Date 9-21-98

73-77/839
1

Pay to the Order of Western KY Gas $ 73,303 00

Seventy-Three Thousand Three Hundred Three and 00/100 Dollars

Security features are included. Details on back.

Bowling Green Bank & Trust Company, N.A.
An ABC Bank
P.O. Box 1050
Bowling Green, KY 42102

For Gas Line -

[redacted]

MP

⑆083900774⑆ 020547802⑈ 1008

© Clarke American

REGALS WDRG

44

KLEER-FAX RECYCLED
80000 SERIES
10% P.C.W.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 44, a - b
Witness: Gary Smith

Data Request:

44. Refer to Mr. Smith's testimony at page 18, lines 4-18.

a. Provide Mr. Smith's understanding of the market saturation, or market share, of new residential and small commercial construction served by gas.

b. Explain how the proposed Premises Charge (for example, see Ives' testimony at page 10, lines 9-18) is consistent with aggressively marketing gas and addressing electric competition for new residential construction.

Response:

a. Western does not possess data that would indicate the percent of new residential and small commercial construction that utilizes gas service. Western has assessed the residential market saturation for homes located on the Company's gas mains, discovering that 98.5% of those homes utilize gas service (see testimony in the Company's Application, Volume 2 of 10, Tab 11, page 12, lines 14-16).

b. The proposed Premises Charge, as well as other rate design features of Western's case, will help Western in competing with electricity in the residential market. In fact, these rate design elements are essential to maintain Western's competitive viability.

Please reference my testimony, Volume 2 of 10, Tab 11, of the Company's application, at page 18, line 2 through page 20, line 8, which addresses the problems faced by Western in the residential market under current rate structures.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 44, a - b
Witness: Gary Smith

It is Western's desire that reasonable system expansion continues to occur to meet the service desires of nearby homes. Under current rate structures and main extension guidelines, the extension of service to new residential customers is unprofitable. The Premises Charge is designed to sustain Western financially as we add new residential service connection, fundamental to maintaining our competitive viability in this market.

Lastly, please refer to Mr. Gruber's response to AG Data Request 33(b).

45

RECYCLED 80000 SERIES 10% P.C.W.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 45
Witness: Gary Smith

Data Request:

45. Refer to Mr. Smith's testimony at page 16, lines 1-2. Please provide the amount of subsidy provided by industrial customers to residential customers. Please also provide workpapers depicting the calculation of the subsidy amount Mr. Smith is addressing in this part of his testimony.

Response:

The term "subsidize", in this context, refers to the state of general effectiveness of the Company's rate design among various customer classes. We consider that effective rate design balances several factors, such as incremental costs, embedded costs, and competitive market conditions. Although not relied upon solely as a guideline to Western's rate structure proposals, I will utilize the embedded cost studies submitted by the Company in this case to respond to this request.

Western submitted an embedded class cost of service study as FR 10(9)(v) in the Company's application. This study was later updated to reflect test year revenues and costs of service for the Company, submitted under PSC DR #2, Item 69. The Company's study uses cost allocation guidelines in the Commission's Administrative Case No. 297 and in subsequent gas company rate cases.

Natural gas systems and operations largely consist of joint and common costs. Embedded cost of service studies utilize certain allocation methods to allocate shares of these joint and common costs to individual customer classes. The results of these models, such as rates of return by customer class, are highly sensitive to the allocations applied to these costs. Allocation methodologies utilized in the study filed by the Company for joint and common costs result in a very large share of these costs being allocated to the industrial sector.

Referring to the test year class cost of service study under present rates, (PSC DR #2, Item 69), class rates of return for residential customers are 3.57% and 13.42% for Interruptible/Carriage customers. Only the Large Interruptible/Carriage class had a negative class rate of return. However, these are primarily special contract customers. Competitive factors necessitated Commission-approved discounted rates to retain these bypass-vulnerable customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 45
Witness: Gary Smith

Cost of service studies that use different allocation methods produce substantially different results. For example, Western's response to PSC DR #2 - Item 70 and PSC DR #2 - Item 71 utilizing different allocation methods than Western's original study. The returns stated in the DR # 2 - Item 71 range from 1.72% for the residential class to 36.9% for the Interruptible/Carriage class. (See referenced KPSC data requests for workpapers.)

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 46
Witness: Gary Smith

Data Request:

46. Refer to Mr. Smith's testimony at page 16, lines 12-13. Explain how the Company's non-industrial customers are not going to participate in the "suffering" from the loss of industrial revenues under the Company's proposal to shift this revenue loss to non-industrial customers in this rate proceeding.

Response:

The testimony, at page 16, lines 12-13, referenced above is in the section of testimony that describes "Problems with Current Rate Structures", from page 14, line 5 through page 21, line 14. Under current rate structures, the discounts necessary to retain bypass vulnerable accounts are borne exclusively by Western and its shareholders.

Western's Margin Loss Recovery Rider, described at page 29, line 19 through page 31, line 26, does propose to share the impact of the loss of certain industrial revenues between the Company's shareholders and non-industrial customers.

47

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 47
Witness: Gary Smith

Data Request:

47. Refer to Mr. Smith's testimony at page 19, lines 6-7. Please provide the residential fair share amount that Mr. Smith believes residential customers should pay and the amount that residential customers actually pay. The difference between these two amounts should equal the amount Mr. Smith believes is "well less" than the residential fair amount. If the reader is mistaken, please provide residential fair share amount, actual share amount, and the amount by which residential payments are less than the fair share amount to data in the Company's case, if possible.

Response:

Western believes that the residential rates proposed in this case provide fair, just and reasonable rates under test year conditions. Please refer to AG DR # 2, Item number 2 for proposed annual margin for residential sales service, $206.63, the current annual margin of $148.45. The proposed increase is $58.18 per year.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 48
Witness: Gary Smith

Data Request:

48. Refer to Mr. Smith's testimony at page 16, lines 4-5. Please provide Mr. Smith's understanding of the amount of the Company's total cost of service that is associated with the significant portion of Western's annual deliveries to industrial sales and transportation customers. Tie the provided amount to data in the Company's filing.

Response:

Please refer to Westerns response to PSC DR #2, Items No. 70, 71, and 69 for embedded cost of service studies providing the requested information.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 49
Witness: Gary Smith

Data Request:

49. Refer to Mr. Smith's testimony at page 19, lines 19-27. For winters that are 10 percent colder than normal and those that are 10 percent warmer than normal, please provide the dollar amounts that a typical residential customer would save or pay to the Company, respectively, under operation of the proposed Weather Normalization Adjustment clause. The answer to this question may be provided by whomever Western feels is the most appropriate person to respond. Provide workpapers detailing the calculation of the requested customer impacts.

Response:

To provide the response this request, I will reference calculations provided in response to several related requests in this Initial AG Data Request.

Base load and heat sensitive factors utilized in this illustration would have been applicable if the WNA had been in effect during the winter of 1998-99. The weighted average rate ("R") is based on the distribution charge proposed by Western in this case.

I also utilized this data to calculate the average natural gas requirements during the months of operation of the WNA.

Based on the attached estimate, the typical residential customer would pay $7.34 through the WNA factor over the course of winter season if weather was 10% warmer than normal. Conversely, if the weather was 10% colder than normal, the typical residential customer would save $7.34 through the WNA factor over the course of winter season. These estimates exclude the impact of Commodity gas cost differences associated with increased/ decreased usage due to the weather variations.

Western Kentucky Gas Company
Case 99-070
Attorney General Initial Data Request Dated August 19, 1999

Line No.	Item (a)	Calculated Value (b)	Source/Calculation Method (c)
1	Normal Lagged Degree-Days, November through April =	3,974.5	Volume 2 of 10, Tab 11 of the Company's Application,
2			Exhibit GLS-4, Sum of Column (e) lines 3 through 8.
3			
4	Variance from normal weather of 10%, in Degree-days =	397.5	Column b, line 1 times 10%
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 152, Sheet 1 of 4, column h, line 17
9			
10	Average Base Load, November-April, Mcf/customer=	9.27	Column b, line 8 times 6 months
11			
12	Weighted Average Rate ("R") for residential class,		
13	at Proposed Rates =	1.2000	AG DR No. 1, Item 153, Sheet 1 of 1, column h, line 8
14			
15	Calculated WNA, at Proposed Rates, at 10% warmer	0.1141	Formula stated in proposed tariff at First-revised Sheet
16	than Normal Weather (ADD = 3,577)		No. 26, applying the factors above on this Schedule.
17			
18	Calculated WNA, at Proposed Rates, at 10% colder	(0.0959)	Formula stated in proposed tariff at First-revised Sheet
19	than Normal Weather (ADD = 4,372)		No. 26, applying the factors above on this Schedule.
20			
21	Estimated Average Normal Residential Usage,	70.5	Column b, line 1 times Column b, line 6 plus
22	November through April		Column b, line 10
23			
24	Mcf variance at 10% variance in normal weather =	6.1	Column b, line 1 times Column b, line 6 times 10%
25			
26	Calculated Total Affect of WNA, at Proposed	$7.34 *	Column b, line 15 times 64.4 Mcf (Column b, line 21
27	Rates, at 10% warmer than Normal Weather		minus Column b, line 24)
28			
29	Calculated Total Affect of WNA, at Proposed	($7.34) *	Column b, line 18 times 76.6 Mcf (Column b, line 21
30	Rates, at 10% colder than Normal Weather		plus Column b, line 24)
31			

32 * - This is the estimated affect of the WNA component on the average residential customers billings through the winter season months of November
33 through April. The impact of Commodity gas cost differences, due to increased or decreased usage are not included in this calculation.

50

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STOCK# 81172

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 50
Witness: Gary Smith

Data Request:

50. Refer to Mr. Smith's testimony at page 22, lines 7-8. Using test year costs and proposed revenues, please provide class amounts of revenues and costs that demonstrate that Western's proposed rates eliminate or lessen existing cross-class subsidies.

Response:

Please refer to Western's response to PSC DR # 2, Items 71 and 69 for embedded cost of service studies providing the requested information.

AG DR-118

KPSC Copy

C.N. 99-070

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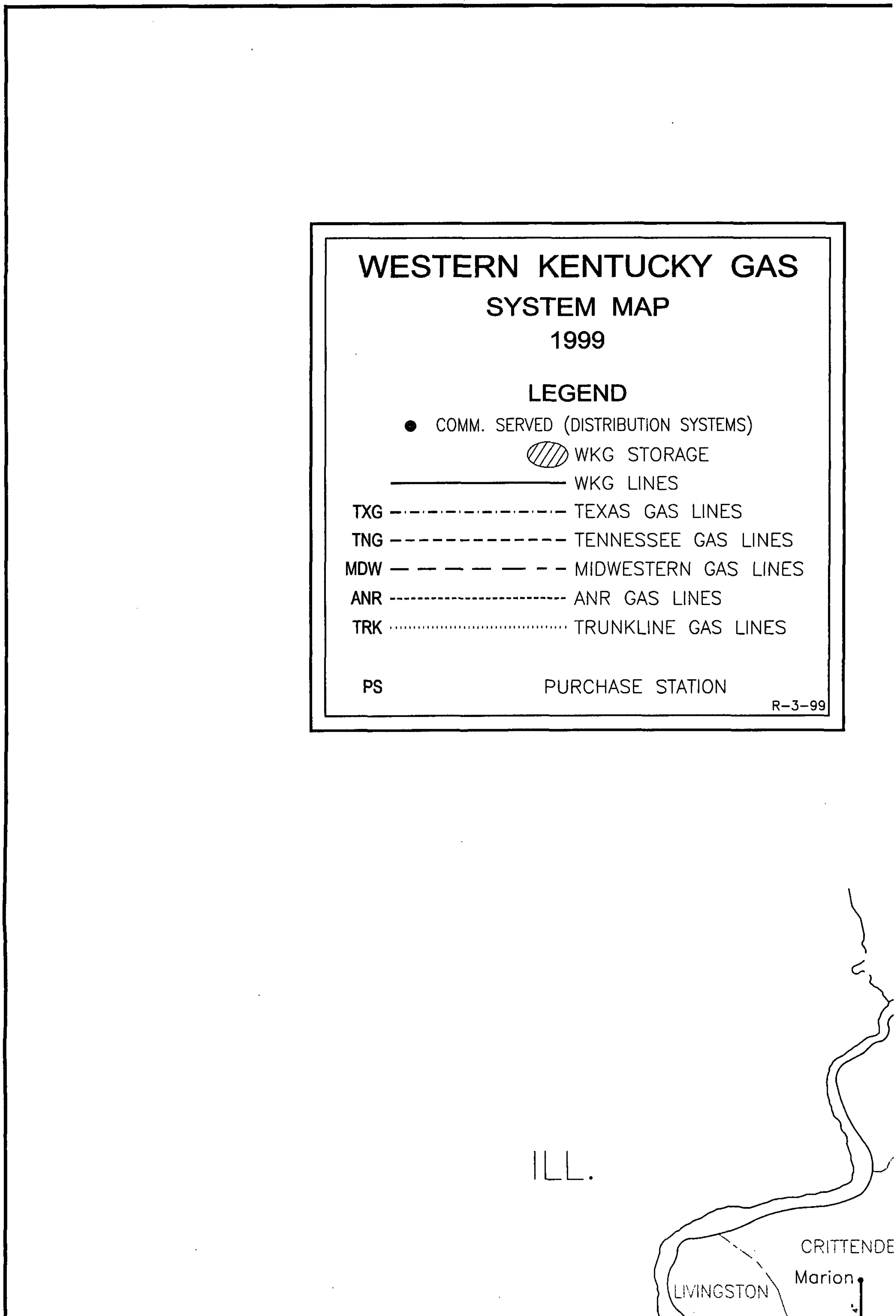
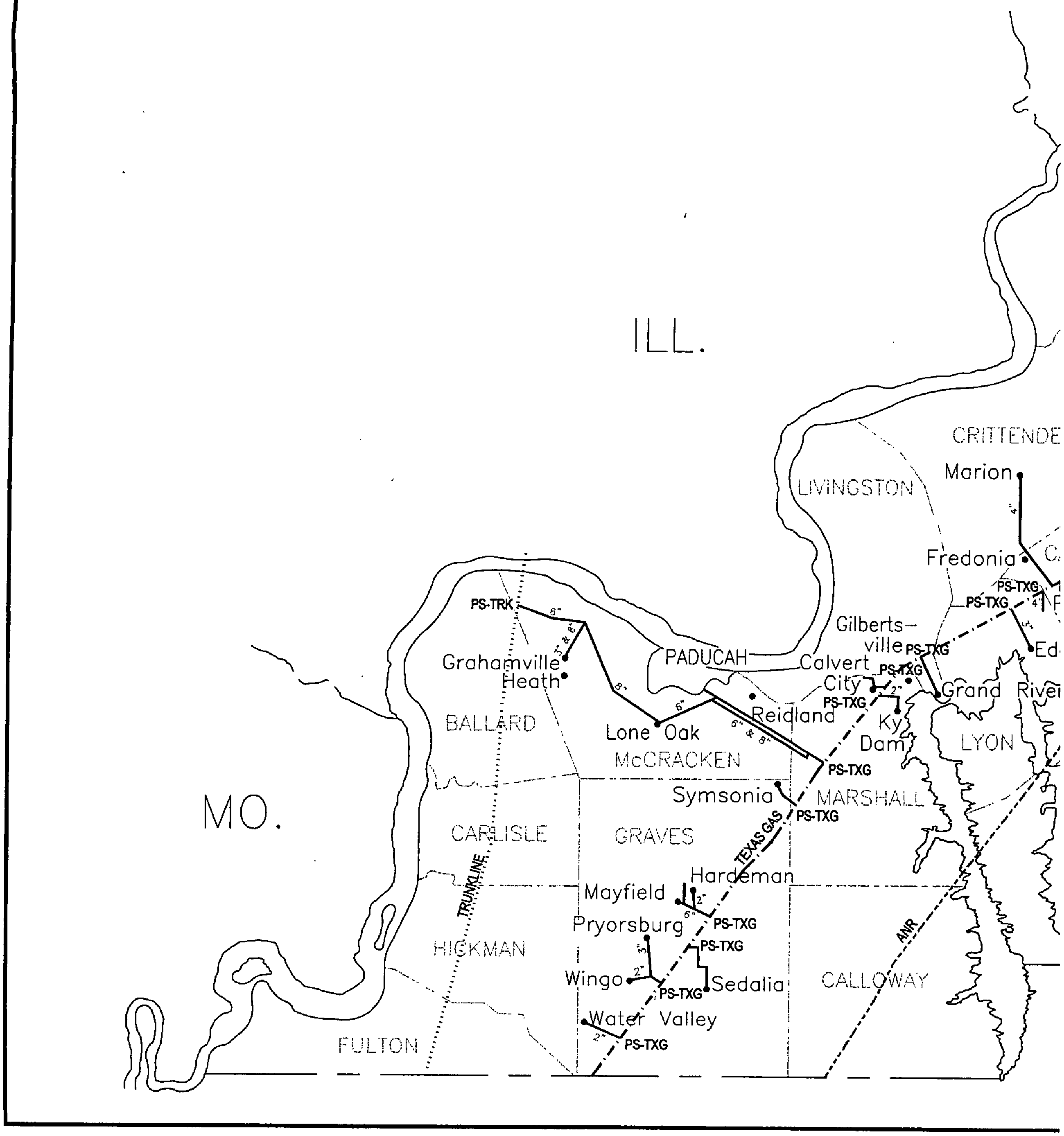


TNG	TENNESSEE GAS LINES
MDW	MIDWESTERN GAS LINES
ANR	ANR GAS LINES
TRK	TRUNKLINE GAS LINES
PS	PURCHASE STATION

R-3-99



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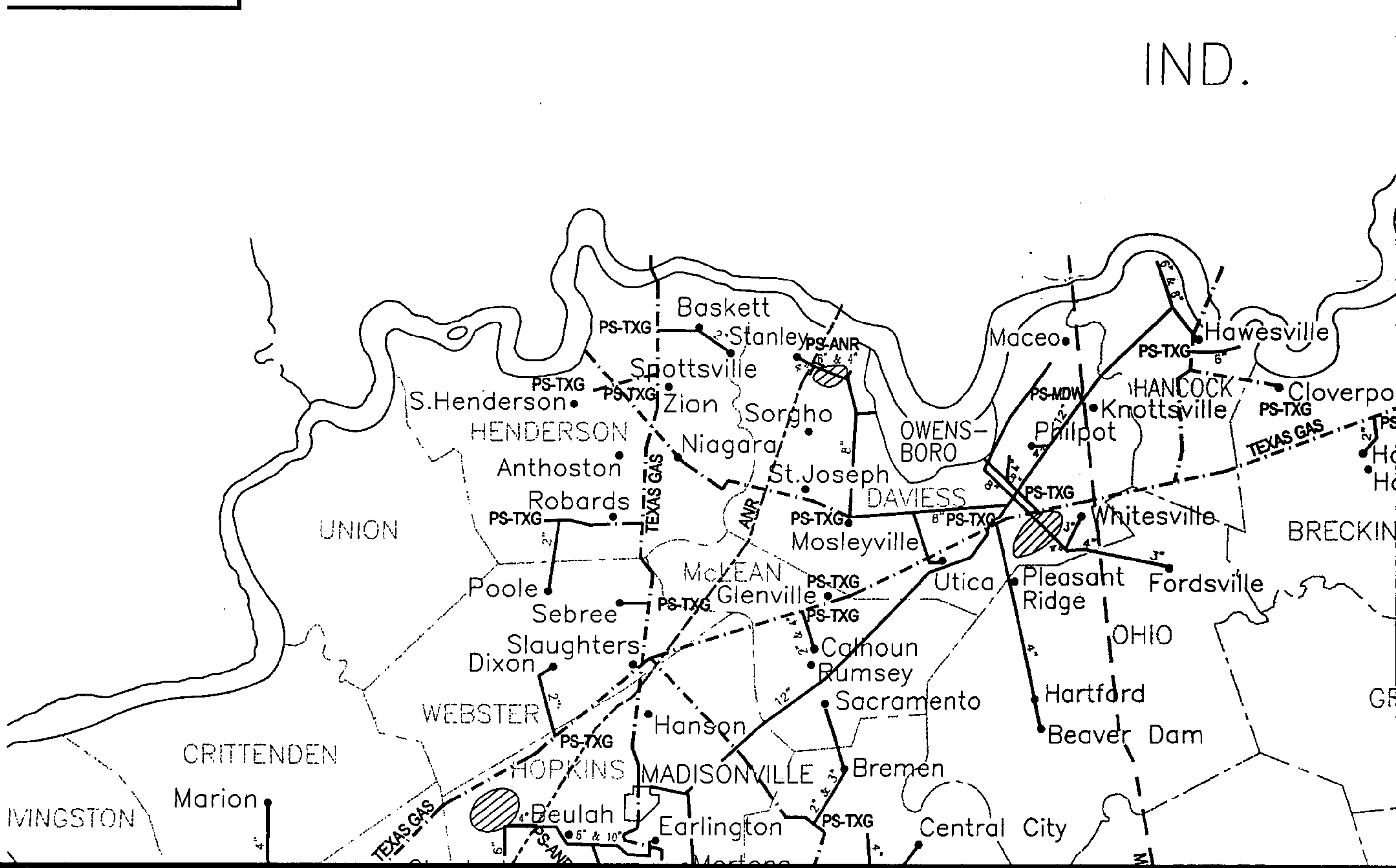

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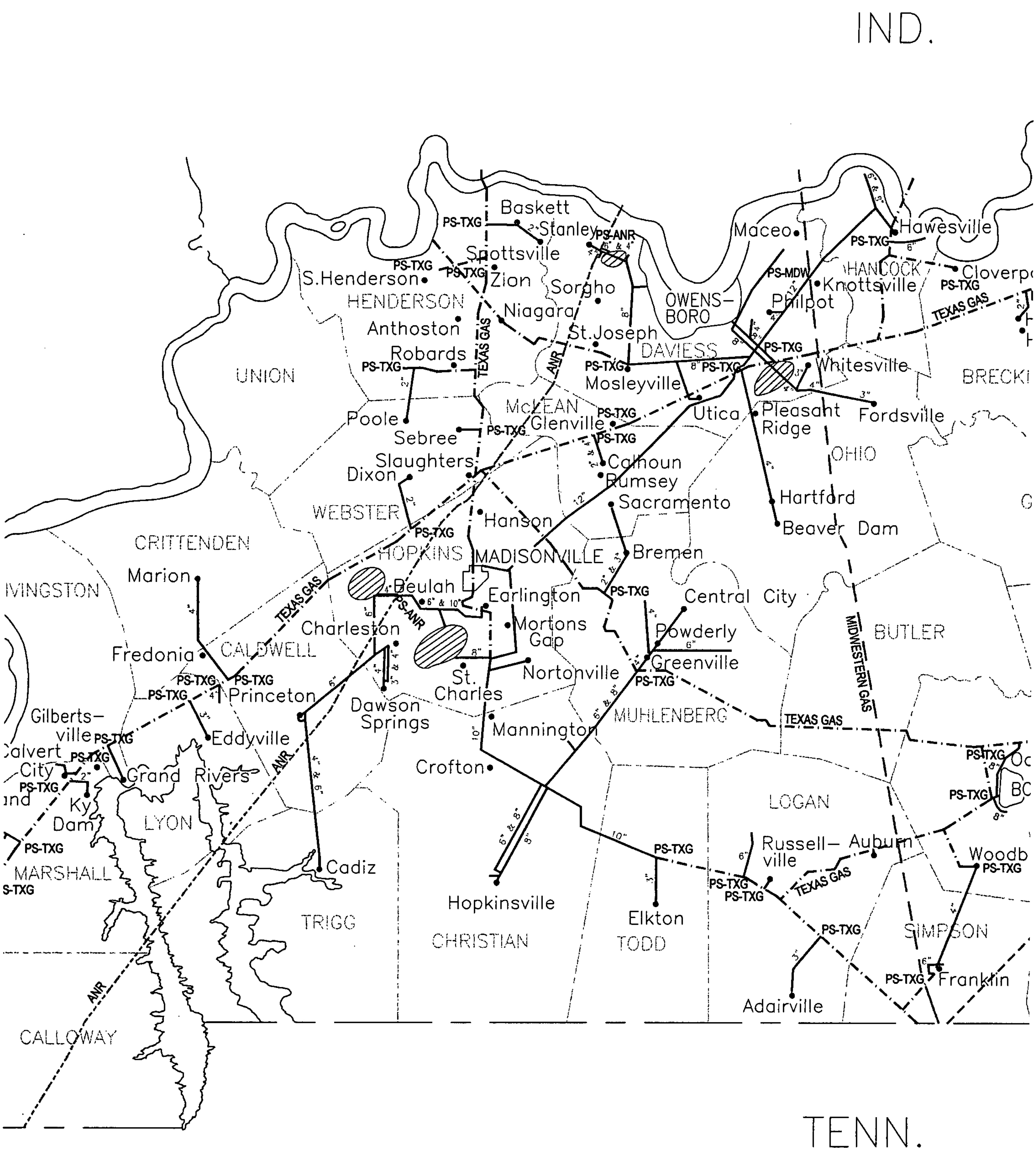

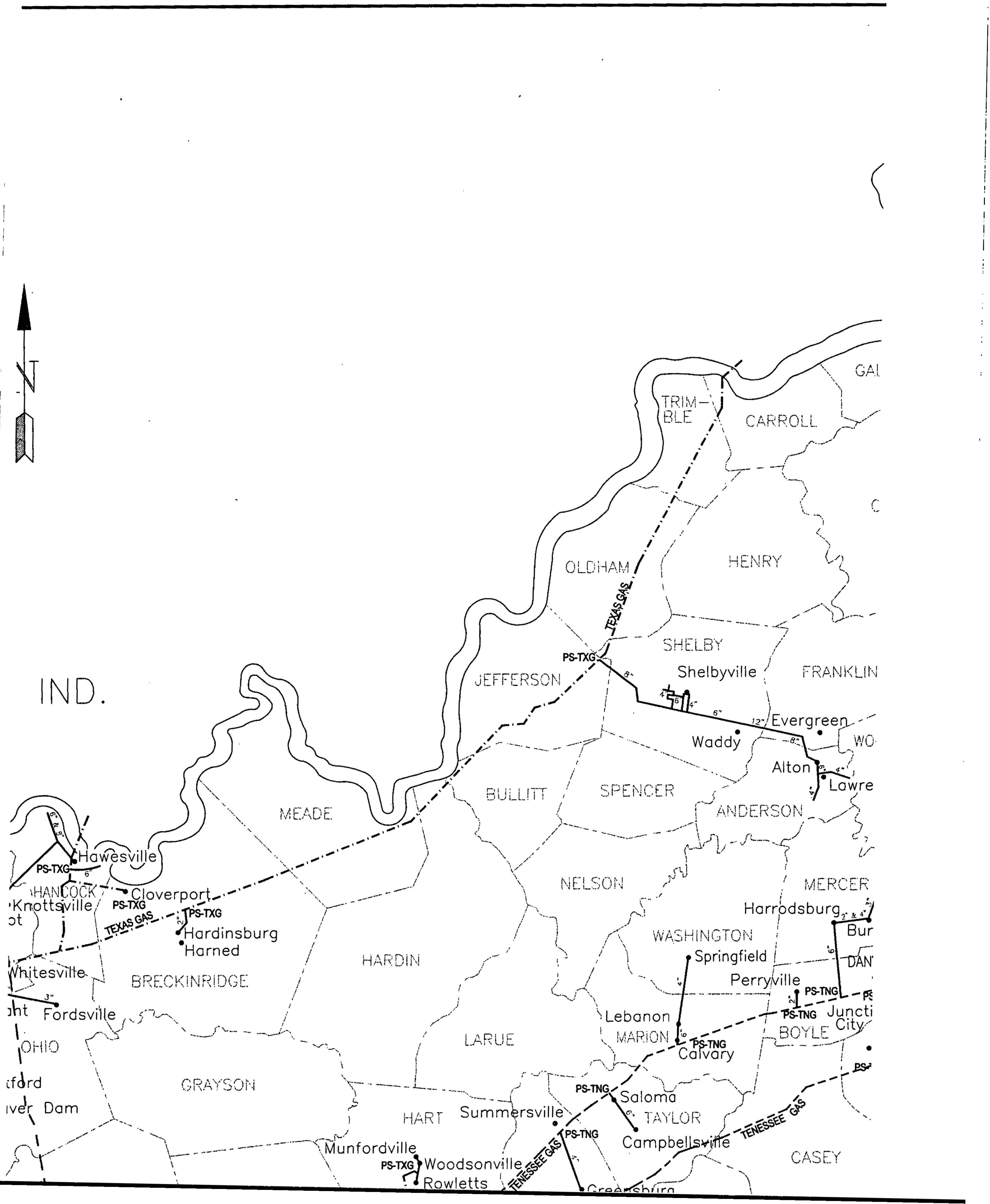

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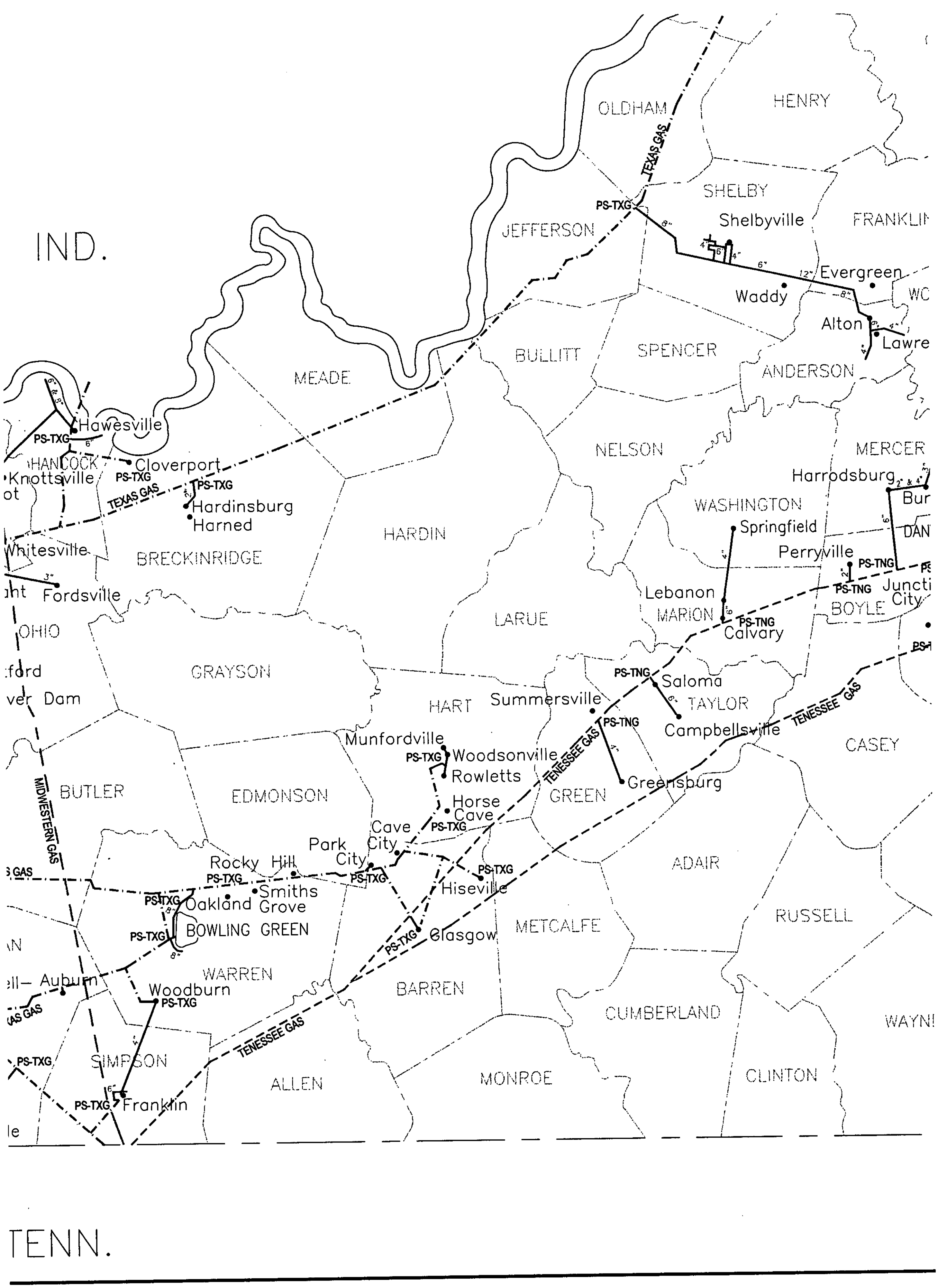

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Park City
Rocky Hill
Smiths Grove
Oakland
Hiseville
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BOWLING GREEN
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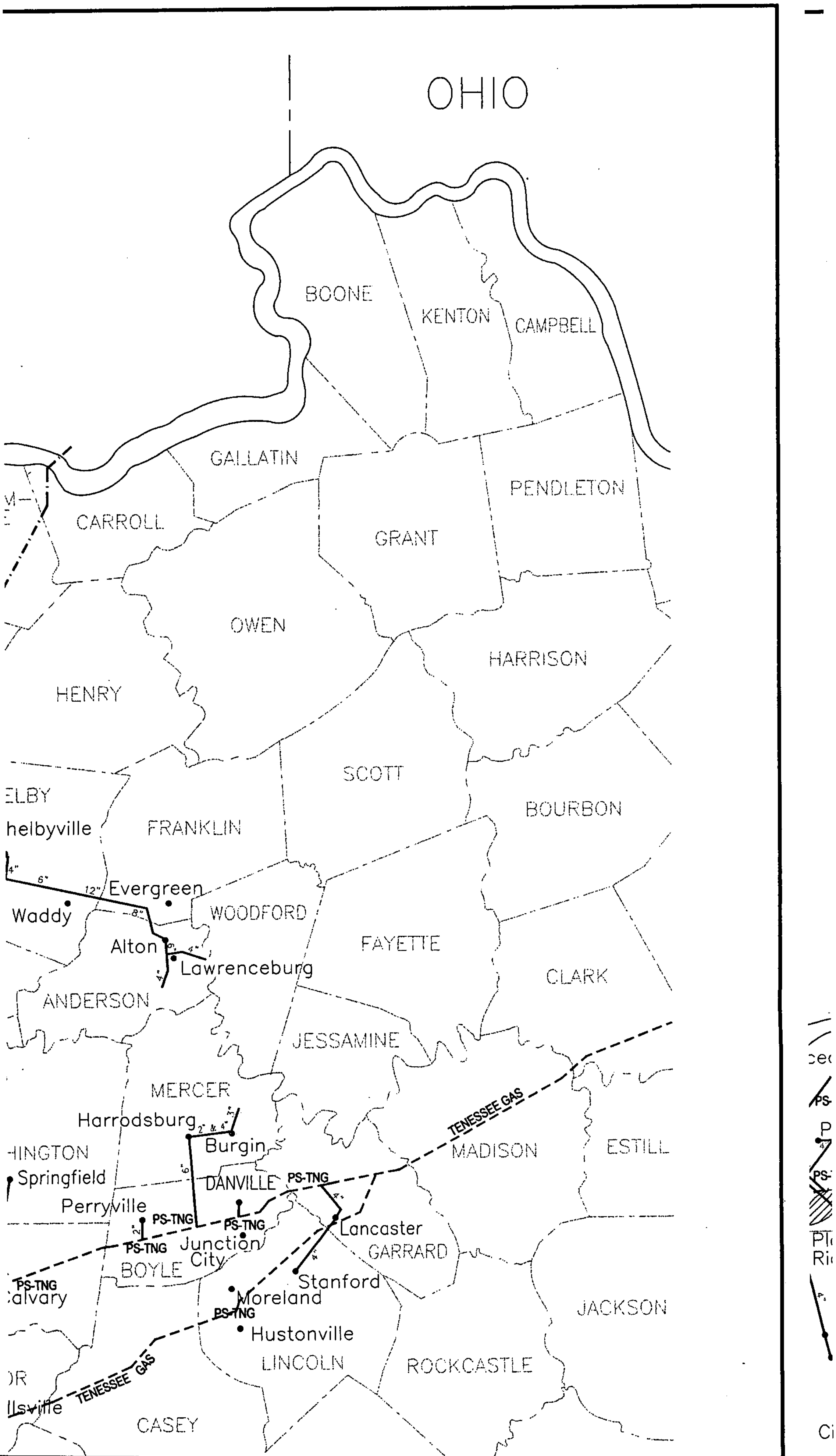
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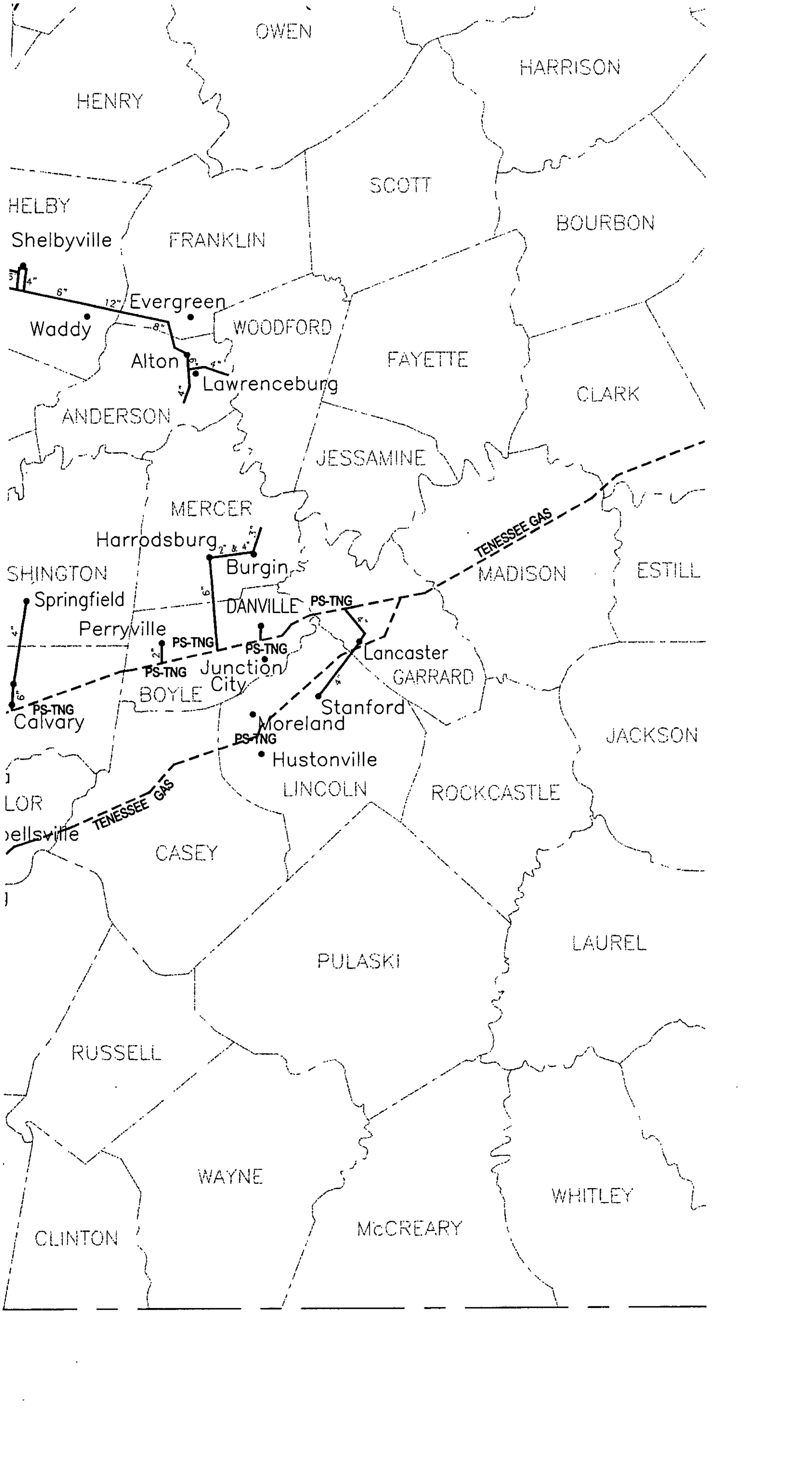

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