COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS	)))	CASE NO. 2013-00148

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on January 23, 2014 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on January 23, 2014 in this proceeding;

- A written log listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on January 23, 2014.

A copy of this Notice, the certification of the digital video record, hearing log, and exhibits have been electronically served upon all persons listed at the end of this Notice. Parties desiring an electronic copy of the digital video recording of the hearing in Windows Media format may download a copy at: http://psc.ky.gov/av_broadcast/2013-00148/2013-00148_23Jan14_Inter.asx. Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 29th day of January 2014.

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Director, Filings Division
Public Service Commission of Kentucky

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS	)) CASE NO. 2013-00148)

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the Hearing conducted in the above-styled proceeding on January 23, 2014 (excluding confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). Hearing Log, Exhibits, Exhibit List, and Witness List are included with the recording on January 23, 2014 (excluding confidential segments and Confidential Exhibits).

2. I am responsible for the preparation of the digital recording.

3. The digital recording accurately and correctly depicts the Hearing of January 23, 2014 (excluding confidential segments).

4. The "Exhibit List" attached to this Certificate correctly lists all Exhibits introduced at the Hearing of January 23, 2014 (excluding Confidential Exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the Hearing of January 23, 2014 (excluding confidential segments) and the time at which each occurred.

Given this 27th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

Session Report - Detail

2013-00148_23Jan2014

Atmos Energy Corporation

Date:	Type:	Location:	Department:
1/23/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Josh Densman - Atmos; Mark Martin - Atmos; Pace McDonald - Atmos; Ernest Napier - Atmos; Bion Ostrander - for AG; Paul Raab - for Atmos; Jason Schneider - Atmos; Gary Smith - Atmos; James Vander Weide - for Atmos; Gregory Waller - Atmos; Glenn Watkins - for AG; Dane Watson - for Atmos
Clerk: Sonya Harward

Event Time	Log Event	
9:44:37 AM	Session Started	
9:44:39 AM	Session Paused	
10:01:55 AM	Session Resumed	
10:02:00 AM	Chairman Armstrong opening statements.	
10:02:40 AM	Introductions of Parties's Attorneys	
	Note: Harward, Sonya	For Atmos - Jack Hughes and Randy Hutchinson; for AG - Gregory Dutton and Dennis Howard; for PSC - Virginia Gregg; for Stand Energy - John Dosker.
10:03:26 AM	Chairman Armstrong	
	Note: Harward, Sonya	Confirms that Public Notice has been given.
10:03:36 AM	Chairman Armstrong	
	Note: Harward, Sonya	Confirms that there are no outstanding Motions.
10:03:49 AM	Public Comments	
	Note: Harward, Sonya	No one present at this time.
10:04:31 AM	Witness Dr. James Vander Weide (for Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Retired Professor from Duke University and President of Financial Strategic Associates.
10:05:27 AM	Direct exam of Witness Vander Weide by Atty. Hutchinson	
	Note: Harward, Sonya	Witness has no changes to his testimony.
10:06:16 AM	Atty. Gregg cross exam. of Witness Weide	
	Note: Harward, Sonya	Referencing Supplemental Response to Item 48 of Staff's 2nd Request.
10:08:51 AM	POST HEARING DATA REQUEST by Atty. Gregg	
	Note: Harward, Sonya	Provide the reason for the exclusion of New Jersey Resources in the updated Discounted Cash Flow Analysis.
10:09:10 AM	Atty. Gregg to Witness Vander Weide	
	Note: Harward, Sonya	Referencing Revised Table 3, Modeled Results.
10:12:05 AM	PSC - Exhibit 1	
	Note: Harward, Sonya	Regulatory Research Associates - Regulatory Focus - January 15, 2014 - Major Rate Case Decisions--Calendar 2013
10:13:34 AM	Atty. Gregg to Witness Vander Weide	
	Note: Harward, Sonya	Referencing page 8 of PSC - Exhibit 1 of this Hearing.
10:16:49 AM	Vice Chairman Gardner cross exam. of Witness Vander Weide	
	Note: Harward, Sonya	Asking about ROE analysis concerning differences due to location/jurisdiction.
10:19:11 AM	Commissioner Breathitt cross exam. of Witness Vander Weide	
	Note: Harward, Sonya	Asking what the average ROE is for the Atmos operating companies.
10:20:10 AM	Atty. Hutchinson	
	Note: Harward, Sonya	To Commissioner Breathitt, the answer may have been provided in a data request and they will research the location or they will provide as a POST HEARING DATA REQUEST.

10:20:59 AM	Atty. Hutchinson redirect. exam of Witness Vander Weide	
10:22:05 AM	Atty. Howard cross exam. to Witness Vander Weide	
10:23:00 AM	Vice Chairman recross of Witness Vander Weide	
10:23:20 AM	Atty. Howard recross of Witness Vander Weide	
10:24:26 AM	Witness Vander Weide dismissed.	
10:24:40 AM	Witness Dane Watson (for Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Managing Partner of Alliance Managament Group
10:25:36 AM	Direct exam. of Witness Watson by Atty. Hutchinson	
	Note: Harward, Sonya	No change to his testimony.
10:26:07 AM	No questions for this Witness.	
10:26:13 AM	Witness Watson dismissed.	
10:26:26 AM	Witness Mark Martin (Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Atmos Energy, Vice President of Rates and Regulatory Affairs
10:27:25 AM	Direct exam. of Witness Martin by Atty. Hutchinson	
	Note: Harward, Sonya	One addition to Witness's Tesitmony - presents Atmos - Exhibit 1 to this Hearing.
10:27:49 AM	Atmos - Exhibit 1	
	Note: Harward, Sonya	Current Rates and Proposed Rates Tables listing GCAs and Tariffs of Atmos, Columbia, Delta, Duke, and LG&E
10:29:47 AM	Atty. Dutton cross exam. of Witness Martin	
10:35:34 AM	Atty. Dutton to Witness Martin	
	Note: Harward, Sonya	Questioning about lost revenues recovered with DSM programs.
10:38:45 AM	Atty. Dutton to Witness Martin	
	Note: Harward, Sonya	Questioning about the request for a margin loss rider.
10:43:06 AM	Atty. Dutton to Witness Martin	
	Note: Harward, Sonya	Asking about Atmos's use of a future test year.
10:43:23 AM	Atty. Hutchinson Objection	
	Note: Harward, Sonya	Atty. Dutton asking for legal conclusion.
10:43:32 AM	Atty. Howard's Response to Objection	
	Note: Harward, Sonya	Suggesting that Witness should answer if he knows the answer.
10:44:34 AM	Atty. Hutchinson Objection	
	Note: Harward, Sonya	Again, Atty. Dutton is asking for legal conclusion.
10:44:41 AM	Atty. Dutton Response to Objection	
	Note: Harward, Sonya	Asking if there is a burden, not if Witness accepts that burden.
10:46:43 AM	Atty. Dutton to Witness Martin	
	Note: Harward, Sonya	Asking about NARUC and his knowledge of their research.
10:47:33 AM	Hearing going into Confidential Session.	
10:47:41 AM	Private Recording Activated	
11:15:11 AM	Public Recording Activated	
11:15:14 AM	Hearing Resuming in Public Session	
11:15:17 AM	Atty. Dutton to Witness Martin	
	Note: Harward, Sonya	Referencing Atmos - Exhibit 1 to this Hearing.
11:17:35 AM	Atty. Dosker cross exam. Witness Martin	
	Note: Harward, Sonya	Referencing Atmos - Exhibit 1 to this Hearing, and his inclusion of gas costs.
11:20:00 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Asking about Responses to Staff's 2nd Request for Information, Items 1, 7, 8, and 14 through 22.
11:21:30 AM	Atty. Gregg. to Witness Martin	
	Note: Harward, Sonya	Witness Martin agrees that the company will file tariff sheets with changes to comply with Commissions regulations.
11:23:40 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 2nd Request, Item 3.

11:26:44 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 2nd Request, Item 26.b.
11:29:16 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 28.
11:33:22 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 3rd Request, Item 4.c.
11:34:57 AM	POST HEARING DATA REQUEST by Atty. Gregg	
	Note: Harward, Sonya	Provide Atmos Mississippi's current bench mark return, including the performance adjustor discussed on page 20 of the tariff.
11:35:50 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 3rd Request, Item 4.d.
11:37:52 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 3rd Request, Item 5.
11:40:32 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 30.
11:41:26 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 3rd Request, Item 27.
11:43:39 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Response to Staff's 2nd Request, Item 11.
11:46:20 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Asking about door tag hanging program/fee.
11:48:05 AM	Chairman Armstrong interjects a question.	
	Note: Harward, Sonya	Asking about the door hanger tag cost being eliminated.
11:51:00 AM	Commissioner Breathitt interjects a question.	
	Note: Harward, Sonya	Asking how long West Texas Division has being doing the door hanger program.
11:52:08 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 24, and Response to Staff's 2nd Request, Item 29.
11:55:43 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 3, lines 8-20.
11:57:19 AM	Atty. Gregg to Witness Martin	
	Note: Harward, Sonya	Makes a reference to CN 95-10.
11:58:24 AM	Vice Chairman Gardner cross exam. of Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 7.
12:01:09 PM	Vice Chairman Gardner to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 9.
12:02:26 PM	Vice Chairman Gardner to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 11.
12:04:55 PM	Vice Chairman Gardner to Witness Martin	
	Note: Harward, Sonya	Asking about weather normalization.
12:09:16 PM	Vice Chairman Gardner to Witness Martin	
	Note: Harward, Sonya	Asking about Economic Development Rider Customers.
12:14:17 PM	POST HEARING DATA REQUEST by Vice Chairman Gardner	
	Note: Harward, Sonya	Provide the amount of the increase that you are requesting that relates merely to the rolling in of the BRP into base rates?
12:15:44 PM	Break	
12:15:52 PM	Session Paused	
1:30:22 PM	Session Resumed	
1:30:28 PM	Commissioner Breathitt cross exam. of Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 5.
1:31:47 PM	Commissioner Breathitt to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, pages 7 - 8, and 19 - 20, concerning lack of growth.

1:34:32 PM	Commissioner Breathitt to Witness Martin	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 29, regarding the System Development Rider.
1:36:00 PM	Commissioner Breathitt to Witness Martin	
	Note: Harward, Sonya	Asking the difference between sales and transportation customers.
1:36:54 PM	Chairman Armstrong cross exam. of Witness Martin	
	Note: Harward, Sonya	Asking clarifying questions about the door hanger program.
1:40:25 PM	Chairman Armstrong to Witness Martin	
	Note: Harward, Sonya	Asking about how often there are inspections on pipelines.
1:41:45 PM	Chairman Armstrong to Witness Martin	
	Note: Harward, Sonya	Asking about Pipe Replacement Program.
1:41:55 PM	Camera Lock Deactivated	
1:47:27 PM	Commissioner Breathitt to Witness Martin	
	Note: Harward, Sonya	Asking about the purchase of the Livermore System and if they'd decline to purchase a smaller system in the future.
1:48:55 PM	Atty. Hutchinson redirect of Witness Martin	
1:48:58 PM	Atty. Hutchinson to Witness Martin	
	Note: Harward, Sonya	Witness Martin is able to provide information requested earlier in the Hearing. ROE in Mississippi is 10.2, which contains a perfomance factor.
1:50:45 PM	Atmos - Exhibit 2	
	Note: Harward, Sonya	Atmos Energy Corporation, Kentucky/Mid-States Division, Kentucky Jurisdiction Case No. 2013-00148, Monthly Jurisdictional Operating Income by FERC Account, Base Period: Twelve Months Ended July 31, 2013
1:51:15 PM	Atty. Hutchinson to Witness Martin	
	Note: Harward, Sonya	Asks Witness to describe Atmos - Exhibit 2 to this Hearing.
1:54:21 PM	Atty. Dutton recross of Witness Martin	
	Note: Harward, Sonya	Asking about Riders in Mississippi and Viriginia.
1:55:04 PM	Atty. Gregg recross of Witness Martin	
	Note: Harward, Sonya	Asking about the 10.2 ROE number provided when questioned by Atty. Hutchinson.
1:57:41 PM	Witness Martin is dismissed.	
1:57:49 PM	Witness Paul Raab (for Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Consultant
1:59:07 PM	Direct exam. of Witness Raab by Atty. Hutchinson	
	Note: Harward, Sonya	No changes to Witness's testimony.
1:59:32 PM	Atty. Dutton cross exam. of Witness Raab	
2:00:34 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Witness's Cost-of-Service Study.
2:08:34 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Watkins Direct Testimony, page 22, Table 2, lines 20-23.
2:09:27 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, pages 9-10.
2:10:53 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Watkins Direct Testimony, chart on page 7.
2:11:27 PM	AG - Exhibit 8	
	Note: Harward, Sonya	Table 1. Source: Watkins Direct Testimony, page 7.
2:15:01 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5, lines 8-12.
2:18:06 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Continuing to question about allocations of costs.

2:22:34 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 15.
2:24:00 PM	Atmos - Exhibit 9	
	Note: Harward, Sonya	Gas Distribution Rate Design Manual, Prepared by the NARUC Staff Subcommittee on Gas, June 1989, National Association of Regulatory Utility Commissioners
2:28:28 PM	Atty. Dutton to Witness Raab	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5, lines 15-17.
2:29:38 PM	Atty. Gregg cross exam. of Witness Rabb	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 24.
2:30:04 PM	POST HEARING DATA REQUEST by Atty. Gregg	
	Note: Harward, Sonya	From page 24 of Witness's Rebuttal Testimony, line 9, provide supporting calculations of the $15,22 amount and include the amounts taken from Mr. Watkins's Cost-of-Service Study and the location of those amounts in this study.
2:31:05 PM	Vice Chairman Gardner cross exam. of Witness Raab	
	Note: Harward, Sonya	Asking about the Witness's reference to the radical departure if Commission adopted Mr. Watkins' approach compared to the Witness's approach.
2:35:47 PM	Commissioner Breathitt interjected with a question.	
2:37:38 PM	Vice Chairman Gardner to Witness Raab	
	Note: Harward, Sonya	Asking if Witness looked at other PSC decisions concerning his Cost-of-Service Study.
2:39:54 PM	Vice Chairman Gardner to Witness Raab	
	Note: Harward, Sonya	Referencing Martin Rebuttal Testimony, page 13.
2:42:30 PM	Witness Rabb	
	Note: Harward, Sonya	References his Rebuttal Testimony, PHR-3, page 2 of 75.
2:45:57 PM	Atty. Dutton recross of Witness Rabb	
	Note: Harward, Sonya	Asking how many Cost-of-Service Studies were presented in this case.
2:46:57 PM	Witness Rabb dismissed.	
2:47:43 PM	Witness Ernest Napier (Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Atmos Energy, Vice President of Technical Services
2:48:43 PM	Direct exam. of Witness Napier by Atty. Hutchinson	
	Note: Harward, Sonya	No changes to Witness's testimony.
2:50:20 PM	Atty. Howard cross exam. of Witness Napier	
	Note: Harward, Sonya	Asking about meter reading program and the direction Atmos plans to move in for the future concerning this technology.
2:53:47 PM	Vice Chairman Gardner interjects.	
2:56:25 PM	Atty. Howard to Witness Napier	
	Note: Harward, Sonya	Asking Witness to read question and answer to OAG 1-052.
2:58:33 PM	Atty. Howard to Witness Napier	
	Note: Harward, Sonya	Asking if there will be a break-even point by discontinuing use of current meters.
3:00:23 PM	Vice Chairman Gardner cross exam. Witness Napier	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 12.
3:03:09 PM	Vice Chairman Gardner to Witness Napier	
	Note: Harward, Sonya	Asking about how many meters Atmos has in Kentucky, how many it will install per year, and how many years it will take to install them all.
3:07:40 PM	Vice Chairman Gardner to Witness Napier	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 17,
3:08:41 PM	Vice Chairman Gardner to Witness Napier	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 16.

3:09:40 PM	Atty. Howard recross of Witness Napier Note: Harward, Sonya — Asking about battery power and reliability.
3:11:18 PM	Witness Napier dismissed.
3:11:28 PM	Witness Jason Schneider (Atmos) takes the stand and is sworn in. Note: Harward, Sonya — Atmos Energy, Director of Accounting Services
3:12:09 PM	Direct exam. of Witness Schneider by Atty. Hutchinson Note: Harward, Sonya — No changes to Witness's testimony.
3:12:31 PM	Atty. Gregg cross exam. of Witness Schneider Note: Harward, Sonya — Referencing Witness's Rebuttal Testimony, page 5, lines 11-13.
3:13:56 PM	Vice Chairman Gardner cross exam. of Witness Schneider Note: Harward, Sonya — Asking about the sales of operations in other states and the gain from those sales.
3:16:49 PM	Witness Schneider Note: Harward, Sonya — Response to AG's Request, 2-82, part G.
3:18:03 PM	POST DATA REQUEST HEARING by Vice Chairman Gardner [Answered later in the Hearing.] Note: Harward, Sonya — Description of how much of proceeds of those divisions was spent on Kentucky?
3:19:11 PM	Commissioner Breathitt cross exam. to Witness Schneider Note: Harward, Sonya — Referencing Witness's Direct Testimony, page 4.
3:20:31 PM	Witness Schneider dismissed.
3:20:41 PM	Break
3:20:45 PM	Session Paused
3:23:59 PM	Session Resumed
3:24:04 PM	Witness Napier taking the stand again.
3:24:22 PM	Atty. Howard to Witness Napier Note: Harward, Sonya — Asking about batteries being garaunteed to operate for 10 years.
3:24:30 PM	Camera Lock Deactivated
3:25:18 PM	Witness Napier dismissed.
3:25:23 PM	Break
3:25:32 PM	Session Paused
3:36:51 PM	Session Resumed
3:36:56 PM	Witness Josh Densman (Atmos) takes the stand and is sworn in. Note: Harward, Sonya — Atmos Energy, Vice Chairman of Finance
3:37:34 PM	Direct exam. of Witness Densman by Atty. Hutchinson Note: Harward, Sonya — Witness has supplement to his Testimony - provides it as Atmos - Exhibit 3 to this Hearing.
3:38:06 PM	Atmos - Exhibit 3 Note: Harward, Sonya — Atmos Energy Corporation, Kentucky/Mid-States Division, Kentucky Jurisdicition Case No. 2013-00148, Monthly Jurisdictional Operating Income by FERC Account, Base Period: Twelve Months Ended July 31, 2013
3:38:57 PM	Atty. Dutton cross exam. of Witness Densman Note: Harward, Sonya — Asking about Consumer Price Index.
3:41:51 PM	AG - Exhibit 10 Note: Harward, Sonya — What goods and services does the CPI cover? Source: http://www.bls.gov/cpi/cpifaq.htm
3:45:39 PM	Atty. Dutton to Witness Densman Note: Harward, Sonya — Referencing Witness's Supplemental Testimony, page 5, line 9-16.
3:48:26 PM	AG - Exhibit 11 Note: Harward, Sonya — Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 1, Question No. 1-111, page 1 of 2, page 2 of 2, and Attachment 1
3:54:38 PM	Atty. Gregg cross exam. of Witness Densman Note: Harward, Sonya — Referencing Witness's Rebuttal Testimony, page 5, lines 17-21.

3:59:14 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Referencing Response to Staff's 2nd Request, Item 62.h.
4:01:21 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Referencing Response to Staff's 3rd Request, Item 11.c.
4:03:27 PM	Commissioner Breathitt interjected a clarifying question.	
4:04:38 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Referencing Response to AG's Request 1-111, page 1 of Attachment 1, under Division of General Office.
4:06:30 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Referencing Response to AG's Request 1-131, pages 4-6.
4:11:52 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 13-14.
4:16:17 PM	Atty. Gregg to Witness Densman	
	Note: Harward, Sonya	Asking about familiarity with rate recovery for employee incentives in cases that have come before this Commission.
4:17:18 PM	PSC - Exhibit 2	
	Note: Harward, Sonya	Commonwealth of Kentucky Before the Public Service Commission, In the Matter of: Application of the Union Light, Heat and Power Company to Adjust Electric Rates, Case No. 91-370, Final Order dated May 5, 1992
4:21:02 PM	PSC - Exhibit 3	
	Note: Harward, Sonya	Commonwealth of Kentucky Before the Public Service Commission, In the Matter of: Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year, Case No. 2010-00036, Final Order dated Dec. 14, 2010
4:26:07 PM	Vice Chairman Gardner cross exam. of Witness Densman	
	Note: Harward, Sonya	Asking about sales of Georgia, Illinois, Iowa, and Missouri assets.
4:28:24 PM	POST HEARING DATA REQUEST by Vice Chairman Gardner [Answered later in the Hearing.]	
	Note: Harward, Sonya	What was the increase percentage of Kentukcy's allocation as a result of these sales?
4:28:31 PM	Atty. Hutchinson redirect of Witness Densman	
4:29:05 PM	Witness Densman dismissed.	
4:29:22 PM	Witness Gregory Waller (Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Atmos Energy, Manager of Rates and Regulatory Affairs
4:30:12 PM	Direct exam. of Witness Waller by Atty. Hutchinson	
	Note: Harward, Sonya	No changes to Witness's Testimony.
4:30:34 PM	Atty. Dutton cross exam. of Witness Waller	
	Note: Harward, Sonya	Asking Witness if there is anywhere that he provided the exact amount of net operating loss carry forward included in this rate case in the accumulated deferred income tax account.
4:32:04 PM	AG - Exhibit 12	
	Note: Harward, Sonya	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 2, Question No. 2-78
4:37:12 PM	AG - Exhibit 13	
	Note: Harward, Sonya	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 1, Question No. 1-047
4:38:19 PM	AG - Exhibit 14	
	Note: Harward, Sonya	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, Staff RFI Set No. 1, Question No. 1-47, page 2 of 3, page 3 of 3, and Attachment 1 to Staff No. 1-47 (4 pages)
4:42:13 PM	Chairman Armstrong interjects.	
	Note: Harward, Sonya	Can the calculation be provided now?

4:43:56 PM	AG - Exhibit 15	
	Note: Harward, Sonya	Exhibit BCO-2, Schedule A-10, Kentucky Office of Attorney General, Remove NOLC ADIT, Atmos Energy Corporation, Forecasted Test Period November 30, 2014
4:45:17 PM	POST HEARING DATA REQUEST by Atty. Dutton	
	Note: Harward, Sonya	Provide the NOLC debit balance and ADIT for Kentucky Atmos for all of the years that there has been a debit balance included in the ADIT related detached losses.
4:46:36 PM	Atty. Gregg cross exam. of Witness Waller	
	Note: Harward, Sonya	Referencing the Application (Schedule J-2) and Response to Staff's 3rd Request, Item 13.b.
4:52:50 PM	POST HEARING DATA REQUEST by Atty. Gregg	
	Note: Harward, Sonya	Provide information about any short term debt that is not included in propose captital sturcture that is used for the purchase of gas that is stored.
4:54:08 PM	Vice Chairman Gardner cross exam. of Witness Waller	
	Note: Harward, Sonya	One answer to previously asked question provided in recorded at AG 1-82 - allocations for past 5 years.
	Note: Harward, Sonya	Answered the question about how much of proceeds was spent on Kentucky from sales of other operations. And the sale price?
5:00:45 PM	Vice Chairman Gardner to Witness Waller	
	Note: Harward, Sonya	Questions concerning Accelerated Depreciation issue.
5:02:33 PM	Atty. Hutchinson redirect of Witness Waller	
5:04:06 PM	Session Paused	
5:04:14 PM	Session Resumed	
5:04:20 PM	Session Paused	
5:04:39 PM	Session Resumed	
5:05:28 PM	Witness Pace McDonald (Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Atmos Energy, Vice President of Taxes
5:06:29 PM	Direct exam. of Witness McDonald by Atty. Hutchinson	
	Note: Harward, Sonya	No change to Witness's Testimony.
5:06:41 PM	Atty. Dutton cross exam. of Witness McDonald	
	Note: Harward, Sonya	Asking about tax calculations.
5:07:51 PM	Atty. Dutton to Witness McDonald	
	Note: Harward, Sonya	Asking what the net operating loss carry forward included in the forecasted test period is.
5:08:31 PM	Atty. Dutton to Witness McDonald	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 6, lines 21-22.
5:10:52 PM	Atty. Dutton to Witness McDonald	
	Note: Harward, Sonya	Discussing a private letter ruling from the IRS.
5:12:16 PM	AG - Exhibit 16	
	Note: Harward, Sonya	Public Service Commission of West Virginia, Charleston, February 11, 2013, Case No. 11-627-F-42T (Reopened), Commission Order
5:13:28 PM	Vice Chairman Gardner cross exam. of Witness McDonald	
	Note: Harward, Sonya	Begins by asking about net operating loss carry forward.
5:21:15 PM	Commissioner Breathitt cross exam. of Witness McDonald	
5:24:39 PM	Atty. Dutton additional cross of Witness McDonald	
5:26:41 PM	Atty. Dutton to Witness McDonald	
	Note: Harward, Sonya	Asking about violation being embedded into tax code.
5:28:35 PM	Vice Chairman Gardner recross of Witness McDonald	
	Note: Harward, Sonya	Asking about tax filings and why amended return will be necessary.
5:31:12 PM	Commissioner Breathitt recross of Witness McDonald	
	Note: Harward, Sonya	Asking about losing accelerated depreciation and bonus depreciation.
5:32:37 PM	Witness McDonald dismissed.	

5:32:49 PM	Witness Gary Smith (Atmos) takes the stand and is sworn in.	
	Note: Harward, Sonya	Atmos Energy, Director of Rates and Regulatory Affairs
5:33:51 PM	Direct exam. of Witness Smith by Atty. Hutchinson	
	Note: Harward, Sonya	No changes to Witness's Testimony.
5:34:02 PM	Atty. Dutton cross exam. of Witness Smith	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 1.
5:35:05 PM	Atty. Dutton to Witness Smith	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 7, lines 20-21.
5:41:15 PM	Atty. Dutton to Witness Smith	
	Note: Harward, Sonya	Asking if Atmos has approached companies with special contracts to renegotiate their contracts.
5:49:04 PM	Atty. Gregg cross exam. of Witness Smith	
	Note: Harward, Sonya	Explain the circumstances that made Atmos enter into special contracts with 17 companies.
5:52:20 PM	Atty. Gregg to Witness Smith	
	Note: Harward, Sonya	Asking what factors Atmos considers for special contracts.
5:54:46 PM	Atty. Gregg to Witness Smith	
	Note: Harward, Sonya	How often does Atmos revisit the price of the special contracts?
5:56:13 PM	Atty. Gregg to Witness Smith	
	Note: Harward, Sonya	What happens at the end of the special contract terms?
5:58:30 PM	Atty. Gregg to Witness Smith	
	Note: Harward, Sonya	Asking if the company feels these contracts are a net benefit.
5:59:41 PM	Atty. Dosker cross exam. of Witness Smith	
	Note: Harward, Sonya	Asking if the special contract customers are served by Atmos's unregulated marketing arm.
6:01:12 PM	Atty. Hutchinson Objection	
	Note: Harward, Sonya	Intervenor involvement is limited to threshold.
6:01:42 PM	Atty. Dosker to Witness Smith	
	Note: Harward, Sonya	Asking if the special customers use the capacity every day of every year on that line.
6:03:13 PM	Atty. Dosker to Witness Smith	
	Note: Harward, Sonya	Anyone other than AEM ever won that RFP and when?
6:04:21 PM	Atty. Dosker to Witness Smith	
	Note: Harward, Sonya	Asking what happens to the capacity that is unused by special contract customers.
6:05:50 PM	Atty. Dutton recross of Witness Smith	
	Note: Harward, Sonya	Asking if there were any negotiation or payback documents produced as part of the record in this case.
6:06:17 PM	Break	
6:06:21 PM	Session Paused	
6:17:48 PM	Session Resumed	
6:18:17 PM	Witness Smith dismissed.	
6:18:30 PM	Concludes Atmos's Witnesses	
6:18:43 PM	Witness Bion Ostrander (for AG) takes the stand and is sworn in.	
	Note: Harward, Sonya	Regulatory Consultant and Certified Public Accountant
6:21:00 PM	Direct exam. of Witness Ostrander by Atty. Dutton	
	Note: Harward, Sonya	Correction to Supplemental Amended Testimony, page 24, line 19, "Schedule A4" should say " Schedule A5".
	Note: Harward, Sonya	Correction to Supplemental Amended Testimony, page 40, both footnotes 14 and 16 refer to "BC04" but should refer to "BC05".
6:22:23 PM	Atty. Hughes cross exam. of Witness Ostrander	
6:23:15 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Originial Testimony, page 8.

6:25:43 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Origninal Testimony, page 8, line 3.
6:28:19 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing BCO, Exhibit 1, Resume.
6:32:07 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Original Testimony, page 9.
6:32:47 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Original Testimony, page 17, line 6.
6:33:02 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Response to Atmos's Request, Item 60.
6:34:37 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Original Testimony, page 47.
6:36:49 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Response to Staff's Request, Item 6.
6:38:41 PM	Atty. Hughes to Witness Ostrander	
	Note: Harward, Sonya	Referencing Treasury Reg. 1.167, as it concerns NOLC.
6:40:22 PM	Witness Ostrander	
	Note: Harward, Sonya	Referencing and reading from Treasury Regulation Section 1.167L-1H6II
6:47:06 PM	Atty. Gregg cross exam. of Witness Ostrander	
	Note: Harward, Sonya	Referencing Witness's Supplemental Testimony, page 10.
6:49:02 PM	Vice Chairman Gardner cross exam. of Witness Ostrander	
	Note: Harward, Sonya	Asking about cases he's worked on with respect to his position on ADIT NOLC.
6:54:25 PM	Vice Chairman Gardner to Witness Ostrander	
	Note: Harward, Sonya	Asking about ADIT NOLC and his views versus Witness McDonald's views.
6:56:00 PM	Atty. Dutton redirect of Witness Ostrander	
7:00:21 PM	Witness Ostander is dismissed.	
7:01:24 PM	Witness Glenn Watkins (for AG) takes the stand and is sworn in.	
	Note: Harward, Sonya	Partner and Senior Economist with Technical Associates Incorporated
7:02:23 PM	Direct exam. of Witness Watkins by Atty. Dutton	
	Note: Harward, Sonya	Correction to Direct Testimony, page 32, line 5, word "if" should be "is".
7:03:18 PM	Atty. Hughes cross exam. of Witness Watkins	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 11, line 16.
7:06:11 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Response to Atmos's Request, Item 63.
7:09:41 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Response to Atmos's Request, Item 74.
7:13:17 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Witness Raab's Rebuttal Testimony, page 24, line 18.
	Note: Harward, Sonya	Referencing GAW-5.
	Note: Harward, Sonya	Referencing Response to Staff's Request, Item 13.
7:16:10 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 15, line 13.
7:18:34 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Schedule GAW-2 and GAW-5.
7:19:25 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 32, line 16.
7:25:00 PM	Atty. Hughes to Witness Watkins	
	Note: Harward, Sonya	Asking about variable cost information the company filed and if Witness did any similiar analysis.

7:26:54 PM	Atty. Gregg cross exam. of Witness Watkins	
	Note: Harward, Sonya	Referencing Staff's Request to AG, Item 15.
7:29:01 PM	Atty. Gregg to Witness Watkins	
	Note: Harward, Sonya	Referencing Witness Martin's Rebuttal Testimony, concerning customer charge.
7:32:39 PM	Atty. Gregg to Witness Watkins	
	Note: Harward, Sonya	Referencing Witness's recommendation for Commission to not approve Atmos's proposed Margin Loss Recovery Rider, and his Response to Staff's Request to AG, Item 14.
7:34:24 PM	Atty. Dutton redirect of Witness Watkins	
	Note: Harward, Sonya	Referencing Schedule GAW-4 of Witness's Direct Testimony.
7:39:24 PM	Witness Watkins dismissed.	
7:40:01 PM	Break	
7:40:08 PM	Session Paused	
7:43:11 PM	Session Resumed	
7:43:19 PM	Deadlines	
	Note: Harward, Sonya	Feb 25 - Briefs
	Note: Harward, Sonya	Feb. 3 - Post Hearing Data Requests
7:45:44 PM	Chairman Armstrong - Closing Comments	
7:45:56 PM	Hearing Adjourned	
7:46:01 PM	Session Paused	
7:59:37 PM	Session Ended	

Name:	Description:
AG - Exhibit 01	CN 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 2, Question No. 2-87, Page 1 of 1
AG - Exhibit 02	CN 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 2, Question No. 2-88, Page 1 of 1
AG - Exhibit 03	CN 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 1, Question No. 1-212 (Supplemental 1), 3 pages
AG - Exhibit 04 - CONFIDENTIAL	Confidential Supplemental Schedule GAW-1, Atmos Special Contracts
AG - Exhibit 05 - CONFIDENTIAL	Case No. 2013-00148, Attachment 6, to OAG No. 1-212
AG - Exhibit 06 - CONFIDENTIAL	Case No. 2013-00148, Attachment 6, to OAG No. 1-212
AG - Exhibit 07 - CONFIDENTIAL	Case No. 2013-00148, Attachment 6, to OAG DR No. 1-212
AG - Exhibit 08	Table 1. Source: Watkins Direct Testimony, page 7.
AG - Exhibit 09	Gas Distribution Rate Design Manual, Prepared by the NARUC Staff Subcommittee on Gas, June 1989, National Association of Regulatory Utility Commissioners
AG - Exhibit 10	What goods and services does the CPI cover? Source: http://www.bls.gov/cpi/cpifaq.htm
AG - Exhibit 11	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 1, Question No. 1-111, page 1 of 2, page 2 of 2, and Attachment 1
AG - Exhibit 12	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 2, Question No. 2-78
AG - Exhibit 13	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, AG DR Set No. 1, Question No. 1-047
AG - Exhibit 14	Case No. 2013-00148, Atmos Energy Corporation, Kentucky Division, Staff RFI Set No. 1, Question No. 1-47, page 2 of 3, page 3 of 3, and Attachment 1 to Staff No. 1-47 (4 pages)
AG - Exhibit 15	Exhibit BCO-2, Schedule A-10, Kentucky Office of Attorney General, Remove NOLC ADIT, Atmos Energy Corporation, Forecasted Test Period November 30, 2014
AG - Exhibit 16	Public Service Commission of West Virginia, Charleston, February 11, 2013, Case No. 11-627-F-42T (Reopened), Commission Order
Atmos - Exhibit 01	Current Rates and Proposed Rates Tables listing GCAs and Tariffs of Atmos, Columbia, Delta, Duke, and LG&E
Atmos - Exhibit 02	Atmos Energy Corporation, Kentucky/Mid-States Division, Kentucky Jurisdiction Case No. 2013-00148, Monthly Jurisdictional Operating Income by FERC Account, Base Period: Twelve Months Ended July 31, 2013
Atmos - Exhibit 03	Atmos Energy Corporation, Kentucky/Mid-States Division, Kentucky Jurisdicition Case No. 2013-00148, Monthly Jurisdictional Operating Income by FERC Account, Base Period: Twelve Months Ended July 31, 2013
PSC - Exhibit 01	Regulatory Research Associates - Regulatory Focus - January 15, 2014 - Major Rate Case Decisions--Calendar 2013
PSC - Exhibit 02	Commonwealth of Kentucky Before the Public Service Commission, In the Matter of: Application of the Union Light, Heat and Power Company to Adjust Electric Rates, Case No. 91-370, Final Order dated May 5, 1992

REQUEST:

Regarding Atmos' response to AG 1-212 (j): For each customer that receives a discounted or negotiated rate, please provide:

a. Customer name;

b. Geographical location (address and GIS coordinates);

c. Name of nearest interstate pipeline; and

d. Approximate distance to nearest interstate pipeline.

RESPONSE:

Please see Attachment 1 to the Company's response to OAG DR No. 2-88 subpart (a).

Respondent: Mark Martin

AG – EXHIBIT 1

REQUEST:

Regarding Atmos' response to AG 1-212(l): For each customer that receives a discounted or negotiated rate, please provide:

a. A map or schematic of the Company's distribution system in proximity to each customer that includes mains diameters and service nodes as available;

b. A list of number of customers (service connections) between each discounted rate customer and the closest upstream main connection to another or larger main; i.e., the main segment serving each discounted rate customer; and,

c. The vintage year in which the main segment serving each discounted rate customer was placed into service.

RESPONSE:

a) Please see the Company's supplemental response to OAG DR No. 1-212 subpart (j).

b) The Company does not maintain these records within its system.

c) Please see the Company's supplemental response to OAG DR No. 1-212 subpart (j).

Respondent: Mark Martin

AG – EXHIBIT 2

SUPPLEMENTAL RESPONSE (9/20/2013)

REQUEST:

With regard to the Company's proposed MLR proposed regulations and rate sheet included in MFR FR 16(1)(b)(4) Attachment 1 (PSC KY No. 2 Original Sheet No. 42), please provide the following regarding the statement in Section 2. Purpose which states, "Margin recovery associated with discounted service that is already reflected in the Company's base rates is prohibited from this Rider":

a. the reference(s) to the current tariff, regulations and/or Commission Order(s) that authorized the Company to allow "discounted service" and the regulatory treatment of the shortfall in revenues associated with these discounted services;

b. an identification of each customer by rate schedule taking discounted service that is included in the test year in this case;

c. the actual rate(s) currently being charged for each of the customers identified in (b), as well as the applicable billing determinants;

d. the revenues collected from the rates provided in (c);

e. the revenues that would have been collected at full tariff rates from the customers identified in (b), as well as the identification of full tariff rates associated with the billing determinants in (c);

f. the treatment of the revenue shortfall (difference between full rates and discounted rates revenues) in this case;

g. all records, documents, evaluations and analyses undertaken by or for the Company associated with each customer in (b) that supports the necessity for a tariff rate lower than the full tariff rate;

h. the annual throughput, revenues collected, and full tariff revenues associated with discounted services provided by the Company separated by rate schedule for each of the last three years;

i. copies of each service contract;

j. map(s) showing the location of each customer and proximity to interstate or other pipelines;

AG – EXHIBIT 3

k. list of each Atmos affiliate that provides gas supply or storage services to each customer identified; and,

l. itemization and gross investment of dedicated facilities (e.g., mains, compressors, regulators, and services) used to serve each customer identified.

SUPPLEMENTAL RESPONSE:

The Company provides the following supplemental responses to OAG DR No. 1-212.

a) The tariff allowing Atmos Energy to enter into special contracts with transportation customers is found in the sections "Transportation Services" in the current tariff. Atmos Energy submitted for Commission review, the special contracts previously provided. They were not submitted as or treated as separate case filings by the PSC. They were reviewed and a letter approving the contract was issued to Atmos Energy. There is no case number or filing number associated with the contracts, so Atmos Energy cannot provide a direct link from the contract filing to the PSC approval letter. There was no rate adjustment associated with the initial contract filing.

In the subsequent rate case, and in all rate cases since, the revenue requirement associated with the previously approved contracts was reviewed by the Commission. In Case No. 99-070, the first rate case after the filing of the initial contracts, the revenue adjustment associated with the special contracts was provided to the Commission as a response to a Staff data request, which revised revenue requirement calculations with the contract adjustments. That adjusted revenue requirement was reviewed by the Commission and included in the final determination of rates. The final order in that case reflects the contract rate adjustments and as such constitutes approval of the "discounted" rates. Because the PSC approved rates that included the modified contract rates, the final order in each rate case represents the approval of the "special contract rate". There is no other PSC order that addresses the contracts.

Please see supplemental Attachment 1 through supplemental Attachment 3 for supporting documentation.

f) Please see the supplemental response to subpart (a). The Commission's final order in Case No. 99-070 approved rates, which included the special contract rates, which authorized Atmos Energy to charge the approved rates.

g) Please see the supplemental response to subpart (a). The documentation of the revenue impact of the contracts and the commission acceptance of the revenue requirement based on those contracts is reflected in the attachments and the final order in Case No. 99-070.

i) Please see supplemental Attachment 4 for the additional service agreements. The service agreements in supplemental Attachment 4 are Confidential. Please note that (b), (c) and (d) in the OAG's September 16, 2013 letter to the Company are actually all one customer, and thus have one service agreement.

j) The Company does not map its distribution system by customer. Please see supplemental Attachment 6. The maps provided in supplemental Attachment 6 are Confidential. The Company has used its existing maps to attempt to satisfy this request.

k) Please see supplemental Attachment 5 for Kentucky special contract customers with the Atmos Energy affiliate. The information in supplemental Attachment 5 is Confidential.

l) Please see the Company's response and attachments to OAG DR No. 2-88 subpart (a).

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, OAG_1-212_Att1_Suppl - Approvals.pdf, 30 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, OAG_1-212_Att2_Suppl - Additional Contract References.xlsx, 3 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, OAG_1-212_Att3_Suppl - Discount Projections.xls, 2 Pages.

ATTACHMENT 4 - Atmos Energy Corporation, OAG_1-212_Att4_Suppl - Special Contracts (CONFIDENTIAL).pdf, 80 Pages.

ATTACHMENT 5 - Atmos Energy Corporation, OAG_1-212_Att5_Suppl - KY Special Contract Customers (CONFIDENTIAL).pdf, 1 Page.

ATTACHMENT 6 - Atmos Energy Corporation, OAG_1-212_Att6 - Special Customers Maps (CONFIDENTIAL).pdf, 18 Pages.

Respondent: Mark Martin

AG – EXHIBIT 4

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

AG – EXHIBIT 5

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

AG – EXHIBIT 6

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

AG – EXHIBIT 7

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

TABLE 1

Allocation Factor	Class			
	Resid.	Commercial/ Public Authority	Firm Ind.	Interrupt./ Transport.
Customers	88.85%	10.91%	0.12%	0.12%
Annual MCF	22.78%	12.71%	1.11%	63.40%
Peak Demand (Design Day)	42.79%	19.23%	1.73%	36.25%

Source: Watkins Direct Testimony, page 7.

AG – EXHIBIT 8

GAS DISTRIBUTION RATE DESIGN MANUAL

Prepared by the
NARUC Staff Subcommittee on Gas

June 1989

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

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AG – EXHIBIT 9

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Richard R. Lancaster, Minnesota PUC
Alice Fernandez, FERC

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NATURAL GAS ACRONYMS

BTU	British Thermal Unit (a measure of heat energy)
DTH	Dekatherm (equal to one million BTU's)
FERC	Federal Energy Regulatory Commission
LDC	Local Distribution Company
MCF	One thousand cubic feet
MFV	Modified Fixed Variable rate design
MMBTU	One million BTU's
NGA	Natural Gas Act of 1938
NGPA	Natural Gas Policy Act of 1978
PGA	Purchased Gas Adjustment
SNG	Synthetic Gas

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

GAS DISTRIBUTION RATE DESIGN MANUAL

Chapter II - Rates Based on Cost of Service

A. Basic Concepts

1. Revenue Requirements

2. Rate Class Determination

3. Rate Design Factors

B. Cost Allocation Studies

1. Customer Costs

2. Commodity Costs

3. Capacity Costs

a. Coincident Peak

b. Non-Coincident Peak

c. Average and Excess

C. Illustrative Cost Allocation Study

D. Marginal Cost Alternative

1. System Cost

2. Gas Cost

E. Rate Design

1. Firm Rates

2. Inverted/Lifeline/Baseline Rates

3. Interruptible Rates

4. Seasonal Rates

5. Demand or Standby Rates

6. Flexible Rates

7. Incentive Rates

F. Other Factors

1. Historical Rates

2. Social and Political Factors

3. Class Risk Differential

Chapter III - Rates Based on Value of Service

A. Basic Concepts

1. Alternate Fuel Competition

2. Gas-to-gas Competition (Bypass)

B. Competitive Rates

1. Rate Determination

2. Minimum-Maximum or Flexible Rates

3. Contribution to Fixed Costs

C. Market Segmentation

1. Ability to Maximize Revenues

2. Discrimination and Price Differentiation

D. Special Rates

1. Economic Development Rates

2. Incentive Rates (e.g. Cogeneration)

Chapter IV - Cost of Gas Adjustments

A. Importance of Gas Costs and Effect on Cost of Service

B. Pipeline Rates

1. Natural Gas Act, NGPA and FERC

2. Demand-Commodity Rate

3. Seasonal/Storage Rate

C. Adjustment Clauses

1. Historical Costs

2. Formulistic Methods

3. Forecasted Gas Costs

4. Allocation of Gas Costs

D. Gas Purchasing Practice Reviews

Chapter 1 - Historical Concepts

A. Brief History of the Natural Gas Industry

Productive use of natural gas in the United States first occurred during the early 1800's. However, difficulties in production and transportation of gas discouraged market growth. Manufactured gas (from coal), although more expensive, was used for illuminating streets and homes. When lighting became powered exclusively by electricity at the turn of the century, gas applications shifted to other markets, most notably heating and cooking.

Then, in the late 1920's, abundant supplies of natural gas were discovered in the new oil and gas fields in the Southwest. Additionally, improvements in pipeline construction technology made long-distance gas transmission practical. These two events, coupled with utilization of the manufactured gas distribution systems, heralded the emergence of natural gas as an important domestic energy source.

Throughout this time interstate sales and transmission of gas were unregulated. With the passage of the Natural Gas Act in 1938, regulation of interstate activities was introduced. This act initiated federal regulation by broadening the scope of the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC).

While there was a reduction in pipeline construction during the Great Depression, construction increased with the end of World War II. Post-war technological advances initiated a period of dramatic growth in the national pipeline system that lasted until the mid-1960's.

During the 1970's the industry experienced significant change as the decline in proved reserves prompted acute shortages. Such decline necessitated supplementation of domestic natural gas supplies with oil and gas imports. In an attempt to deal with the energy crisis, Congress passed the Natural Gas Policy Act (1978) through which both price determination and the regulatory environment were changed.

By the early 1980's the crisis had abated with the emergence of a surplus of gas supply. Changes effected by the NGPA created the need for further regulation of gas transmission. In response to its interpretation of the NGPA and the evolving natural gas market, in 1985 the FERC issued Order No. 436 - a non-discriminatory open-access transportation program. Upon the D.C. Circuit Court's remand to the FERC of certain sections of Order No. 436, the FERC issued Order No. 500 (1987). Order No. 500 promulgated measures to remedy the perceived inequities in Order No. 436, with the intention of further facilitating a competitive natural gas market.

Prior to the current volatility at the interstate level, utilities viewed their participation in the national gas market as somewhat limited. Regulation of distribution originated within the jurisdiction of state and local authorities. However, the advent of increasingly dramatic consequences to utilities by federal promulgations has caused a shift in focus. Both utilities and their respective state commissions have been forced to significantly enlarge the scope of their participation in today's national gas market.

It should also be remembered that, in the federal arena of expanded competition, the concept of gas distribution as a natural monopoly still exists. That concept continues to exert significant influence on the industry.

B. Characteristics of the Natural Gas Industry

1. Natural Monopoly and Need for Regulation

The primary reason for regulation centers on the phenomenon of a natural monopoly. A natural monopoly exists when a single company can supply service at a lower cost than two companies with duplicate facilities and overlapping markets. An additional characteristic of a natural monopoly is the large capital investment required in order to serve customers on demand. The clearest case of a natural monopoly is in local distribution, where a single set of facilities can serve any given number of customers more efficiently than multiple sets of facilities. In such circumstances, unrestricted entry is considered wasteful and inefficient because of excessive investment and clutter of public property with service lines. Although, by definition, a monopoly is the most efficient means to provide utility service, control is needed in order to prevent exploitation of the public by the monopoly in terms of both price and quality of service.

Public utility regulation provides for adequate quality of service at reasonable prices and obligates monopoly companies to provide service to all interested parties without discrimination. Regulation attempts to obtain for the public the benefits gained through competition and the efficiency accomplished through a monopoly. Regulation can be provided by municipal bodies, state commissions, or federal commissions. The extent of jurisdiction varies and depends on a number of different factors.

One of the main reasons for the existence of regulatory agencies is rate regulation. Within rate regulation the cost-of-service principle exists. This principle maintains that a public utility can charge rates reflecting only the cost of providing the service plus a "reasonable" return to investors. Determining actual cost and "reasonable" return makes rate regulation one of the most difficult and controversial issues. Other areas of regulation include accounting, financing, service rules, safety and a variety of other functions.

Public utility regulation, as we know it today, is a product of long years of experimentation developing from the growth of the utility industry and the economy.

2. Industry Sectors

The natural gas industry is composed of four major industry sectors: producers, pipelines, distribution and marketers. Each of these sectors plays a role in the movement of natural gas from the wellhead to the burner tip.

a. Producers

The producers are responsible for locating, drilling, gathering, cleaning, and drying natural gas. Located in various parts of the United States, Canada, and the Outer Continental Shelf, producers have provided natural gas in the United States for over 100 years. Traditionally, producers sold gas only to pipeline companies. However, producers now sell gas to all sectors of the natural gas industry: pipelines, distribution utilities, and marketers.

b. Pipelines

Pipelines are the movers of natural gas. Nationwide, transmission pipelines, up to four feet in diameter, typically carry natural gas from Texas, Oklahoma, Louisiana, and offshore in the Gulf of Mexico to all parts of the United States.

Pipelines are regulated by the FERC under the authority of Section 1(b) of the Natural Gas Act. FERC has regulatory authority over facilities, services, and rates of interstate pipelines.

Traditionally, interstate pipeline companies have been the merchants of natural gas. Each interstate pipeline company bought, delivered, and sold natural gas to one or more local distributing companies. Ancillary to its sales service, the interstate pipeline company often provided storage of large quantities of natural gas to insure delivery as needed by its customers.

However, in today's natural gas industry, interstate pipeline companies have assumed a different role. While still maintaining their merchant function, transportation for interstate pipelines is becoming increasingly important in the restructured natural gas industry. Open access to the transportation facilities of the interstate pipeline by others, primarily distribution companies and marketers, is now changing the way pipelines do business.

c. Distribution Utilities

Across the nation over 1,600 local distribution companies (LDC's) provide gas service to residential, commercial, and industrial customers. These utilities provide the last link between the wellhead and the burner tip. Their rates, services and facilities are subject to the regulations of state and local regulatory commissions.

Traditionally, most local distribution companies have been customers of interstate pipeline companies. The utilities have paid pipeline companies for the gas supply they needed. However, in today's natural gas industry, utilities have the ability to secure system supply directly from gas producers or marketers.

d. Marketers

A new player in the natural gas industry is the gas marketer. This entrepreneur has emerged linking together willing sellers of natural gas to willing buyers of natural gas across the nation. The restructuring of the natural gas industry has opened a niche for this new market player. With increasing numbers of facilities supplying open-access transportation, the business opportunities for the gas marketer have greatly increased.

The gas marketer coordinates with producers, interstate pipelines, and LDCs, arranging marketable packages of gas for sale to end users. The marketer tailors the gas packages to meet the buyer's needs in terms of volume, delivery point, length of delivery, and quality of product. In the coming years, the gas marketer will likely play an increasing role in the national energy market. The marketer has enjoyed an environment relatively, if not totally, free from regulation.

3. General Natural Gas Market

Producers, natural gas pipelines, distribution utilities and marketers are involved in furnishing the commodity to the ultimate users of the product: the residential, commercial, and industrial customers who burn natural gas. Total U.S. natural gas consumption by these customers declined slowly during the 1984-87 period. This downturn in usage (especially in the residential and commercial sectors) is due in part to conservation efforts, energy efficient design, and the weather. But since natural gas is the cleanest, most efficient, and most readily available fuel for America's homes, factories, and electric generators, total natural gas consumption in the next five years is expected to grow.

a. Residential

Residential customers accounted for over twenty-five percent (25%) of total U.S. natural gas consumption in 1985. Approximately 45 million households now depend upon natural gas for part of their energy needs. The major residential applications for the commodity are space heating, water heating, and cooking although some residential space cooling units are also in service today. Since space heating during the winter months is the largest residential application of gas, residential usage is highly seasonal in nature. Due to continued efforts in conservation and the popularity of energy-efficient appliances, total residential natural gas usage is expected to show a slight net decline over the next decade, even though the number of customers is expected to grow.

b. Commercial

The commercial market sector normally includes businesses, hospitals, schools, and some government facilities. Commercial applications for natural gas include space heating and cooling, water heating, and electrical generation. Due to projected increases in commercial square footage and overall commercial energy use, this market sector is expected to have significantly greater natural gas usage during the next several years.

c. Industrial

Approximately forty percent (40%) of total U.S. natural gas consumption is in the industrial market, making this segment the largest consumer sector. Slow to modest growth in consumption is foreseen for this sector during the next several years. The largest portion of industrial natural gas use is for process heating, which refers to the combustion of fuels for the direct transfer of heat in applications such as furnaces, kilns, dryers and heaters. Other major uses of the commodity in the industrial sector include steam generation, space heating and cooling, and feedstock applications, where the fuel is used as a raw material in forming part of the product being processed or produced. In response to the energy shortages experienced during the last decade, many industrial users have installed equipment which allows access to alternative fuel sources and, thus, are often in a position to bargain for lower natural gas commodity rates.

Gas companies furnish service to the three classes of customers under varying circumstances of delivery and use. Most companies divide each of these customer classes into various subclasses (such as interruptible, seasonal and firm) which have specialized rate structures. The rationale behind such differentiation is that each customer in the subclass is deemed to have cost factors or other characteristics peculiar to the subclass. Because these variations result in differences in the cost of rendering service to the various classes, subclassification provides a basis for differences in the pricing.

C. Rate Types

Utility ratemaking has never been an exact science. The rate structure for a utility should normally be designed to recover the total allowed revenue requirement of the utility, including a fair rate of return. While cost is an important factor in ratemaking, actual rates are often designed to incorporate numerous other factors, including technological, economic, regulatory, political, promotional and social. This section includes a discussion of the various types of rates which have been historically used in the gas industry.

1. <u>Unmetered Rate</u>

The unmetered rate was the earliest type of rate used in the gas industry. Under an unmetered rate, a customer is billed a fixed sum for service during a stated period of time regardless of actual gas consumption (e.g. $30 per month). This method was used prior to the introduction of the gas meter and its use was dictated by the technological capabilities of the time. This rate structure was simple and easy to administer, but was not equitable since it meant that a customer who used his gas equipment fully had the same monthly bill as a customer with lesser use. With the advent of gas meters, this type of rate has almost died out, although it is still being used for some outdoor gas lighting because usage is constant.

2. <u>Straight Line Meter or Flat Rate</u>

A number of rate structures have been used since metering was introduced to remedy the inequity of the unmetered rate method. The first such rate structure was the straight line meter rate (now commonly referred to as a flat rate). Under this rate, a customer is billed based on a constant price per unit of gas consumed and registered by the meter (e.g. $3.00 per Mcf). This method is the simplest of all metered rate methods and with some modification is still in common use today.

The flat rate has the disadvantage of assigning costs at a uniform rate and in the same proportion to each volume of usage. For example, if a customer had no gas use in a month, he would have no charge. However, costs were incurred by the gas utility for fixed expenses such as meter reading, carrying cost on investment in facilities, etc. Therefore, each unit sold included an equal amount of the fixed cost, and a large customer would normally subsidize some of the costs of the smaller users. Variations on the flat rate were developed to alleviate this shortcoming, including use of a customer charge to recover some fixed costs and use of quantity discounts to encourage greater consumption and spread fewer fixed costs to the larger customers.

3. Step Meter Rate

A further solution was the introduction of the step meter rate. Under this method, the customer's entire consumption was billed at a certain unit rate. There were various unit rates and the one used depended upon the range into which consumption fell. The greater the consumption, the lower was the unit rate used, e.g. a customer using 100 Mcf or less would be charged $3.00 per Mcf, while one using more than 100 Mcf would be charged $2.50 per Mcf for all of the customer's consumption. This method had two advantages over previous methods: (1) Promotional incentive, and (2) Some cost justification.

However, this method had two shortfalls. First, bills for large use could actually be less than bills for lesser use. In the example above, a customer using 100 Mcf would have a bill of $300, but a customer consuming 101 Mcf would be billed only $252.50. Such a billing result would obviously be inequitable. Second, the system rewarded poor load factor customers who used little or no gas during most of the year, but who used a large amount of gas in sporadic or limited periods and, therefore, created a large investment in production and distribution plant to serve them. Conversely, it penalized good load factor customers who used gas at a steady rate and did not get the reduced unit rate for large users, even though the cost associated with the production and distribution facilities required to serve these customers was low in proportion to their total gas requirements.

4. Declining Block Rate

The step meter rate evolved into the declining block rate. This method provides a declining average unit cost to the customer as usage in a billing period increases. It employs two or more successive blocks with decreasing price, e.g. a rate of $3.00 per Mcf for the first 100 Mcf, and $2.50 for all consumption over 100 Mcf. This system avoids the sometimes inequitable pricing under the step meter rate. In the above example a customer using 100 Mcf would be billed $300, while one taking 101 Mcf would receive a bill for $302.50.

The declining block rate structure was intended to provide a method to equitably recover cost. The unit price for each block may include a portion of capacity costs as well as commodity costs. In other instances, the first blocks of the rate may be used to recover assigned costs while the later blocks are priced with a close relation to commodity costs. This rate structure was also intended to meet competitive situations and to promote the sale of gas by providing a lower marginal cost of gas to larger customers.

5. Inverted Rate

The inverted rate is simply the reverse of the declining block rate. Under the inverted rate structure the rate for successive blocks increases as consumption increases, e.g. a rate of $3.00 per Mcf for the first 100 Mcf, and $3.50 for all consumption over 100 Mcf.

Inverted rates were developed to achieve two goals. First, the gas shortages of the 1970's resulted in an increasing awareness of the value of conservation. Inverted rates were viewed as a method of promoting conservation by discouraging customers from using large quantities of gas. In this respect, the inverted rate was also viewed as being cost-based since the shortage of natural gas had caused it to be a commodity with increasing marginal costs.

The second objective of inverted rates was the desire to provide an affordable level of gas services to meet basic human needs, often referred to as lifeline rates. The natural gas shortage brought about a significant increase in prices. As a result, it was believed that some members of society were unable to afford natural gas to provide for minimal heating and other basic needs. Lifeline rates were designed to provide for these requirements at reduced rates while penalizing excess consumption.

6. Customer Charge

A customer charge is not a different type of rate, but rather is a specific type of charge which may be used with any of the other rate types. The customer charge is typically a monthly charge which is in addition to the volumetric charges, although in some cases it may contain an allowance for a small volume of gas. For example, a typical rate schedule might appear as follows:

Customer Charge:	$5 per month
Commodity Charge:	$3 per Mcf

The basis for the customer charge is that there are certain fixed costs that each customer should bear whether any gas is used at all. Examples of such costs are those associated with a service line, a regulator and a meter, recurring meter reading expenses and administrative costs of servicing the account.

7. Demand or Capacity Charges

Demand charges have commonly been used in the design of interstate pipeline rates for years, but are relatively uncommon for local distribution companies. A demand charge is designed to recover the fixed or capital costs associated with the customer's use of the transmission and distribution system. Like the customer charge, a demand charge can be used with any of the previous rate forms. It has the advantage of allowing the customer's bill to more closely reflect the actual costs incurred by the utility in providing service.

8. Minimum Bills

The term "minimum bill" is used to describe a tariff provision which can have the effect of requiring the customer to pay for a defined minimum level of service. It can take any number of forms, for example a provision where the customer is required to take a specified quantity of gas or pay for it anyway or a straight minimum bill, where the customer is required to pay a set minimum (for example, $1000 per month) when the customer's bill would otherwise be less.

Chapter II - Rates Based on Cost of Service

A. Basic Concepts

1. Revenue Requirements

Traditionally utility rates have been set to permit the company to recover its reasonable cost of providing service plus the opportunity to earn a reasonable return on its investment which is used and useful in providing utility service. Typically the utility will file a rate increase request seeking authority to increase rates by a certain amount. Occasionally, a Commission may initiate a proceeding on its own motion to reduce a utility's rates. The basic objective in either case is to determine the rates necessary to recover the utility's cost of service. The specific method of determining that cost varies somewhat from state to state, but the various methods can be reduced to the following formula:

$$R = E + (B \times I)$$

where E = Expenses
B = Rate Base
I = Overall Rate of Return
R = Revenue Requirement

The expenses are simply the utility's costs which are incurred in serving customers and are not capitalized. They include such items as operations and maintenance, administration, depreciation, taxes, uncollectibles, customer billing and, if not collected through a separate mechanism, cost of gas. It is not uncommon for some expense items to be disallowed because they are not reasonable or prudent, or because they are non-utility expenses. Such disallowed expenses are referred to as being "below the line" and hence not allowable for rate-making purposes. Allowable expenses are "above the line."

Rate base is a utility's plant, net of depreciation, plus working capital, which is used and useful in providing utility service. Most states use historical original cost to determine rate base but some use fair value, which is intended to provide a more up-to-date measure of replacement cost. There are also a variety of methods for dealing with construction work in progress, but this factor is not as significant for gas utilities as it is for electric. Finally, if the utility serves more than one state, it will be necessary to make a jurisdictional separation of rate base and expenses between the portion regulated by the Commission and others. This separation may also be necessary if the utility has affiliated operations which are not regulated.

The utility's overall rate of return represents its weighted average cost of financing through instruments such as common stock, preferred stock, long and short term debt. The purpose is to permit the utility the opportunity to earn a reasonable return on its capital invested in providing utility service. The allowed rate of return on common equity will often be highly controverted, but the other cost elements may not be controversial, especially if they are based on embedded costs.

The elements of expenses, rate base and overall rate of return are then utilized in keeping with the formula to produce the utility's rate case revenue requirement. This represents the total revenues which the rates designed in the case need to produce for the utility to have the opportunity to earn its authorized rate of return. The formula used in the case will often be designed to calculate a revenue deficiency (or excess) at present rates, but at some point this will need to be converted to a revenue requirement for rate design purposes.

2. Rate Class Determination

In order to design rates, it is first necessary to divide the utility's customers into various rate classes. This is done by defining rate classes according to certain characteristics which are common to all members of the class. The specific factors used to define rate classes will depend upon the characteristics of the customer population and the goals to be achieved. Factors which have been used to define rate classes include: (1) size, (2) customer type, (3) type of usage, (4) interruptible or firm service, (5) load factor, and (6) alternate fuel capability. Some of these, such as size, are relatively obvious, though others may require some elaboration.

Customer type basically refers to whether the customer is residential, commercial or industrial. These basic categories are often subdivided. For example, the residential class may be divided into space heating and non-heating, or separate rate classes may be created for senior citizens or low-income customers. These subclassifications are often related to other characteristics, such as size or load factors, but they need not be.

Classification by type of usage is similar to classification by customer type, but is more dependent upon the specifics of the utility's service territory. For example, if a utility is located in an agricultural area, it may be advantageous to design a special rate for grain dryers. These customers have relatively low load factors since they have high consumption during the drying season and little or none during the rest of the year, but they use large volumes of gas, generally are off peak and are price sensitive. A rate class limited to them can prove useful in designing rates to meet the utility's overall revenue requirement. Each utility will have its own unique mix of types of usage and the appropriate rate class determination should consider the particular consumption patterns on the utility's system.

Segmenting customers by load factor (or load consumption characteristics) can serve a purpose similar to dividing them into firm or interruptible categories. Demand for natural gas is seasonal, with northern states having a higher winter peak due to the heavy concentration of space heating. Usually it is desirable to have customers with load factors which reduce or at least don't accentuate the seasonality fluctuations.

In determining which factors to use in setting rate classes, it is necessary to consider the objectives to be achieved. In theory, utility rates could be designed for only a single rate class. However, an appropriate division of customers into rate classes can achieve a variety of goals, including economic efficiency, fairness and equity, reflection of costs, social needs, competitiveness, operating efficiency, business climate development, rate stability, conservation and political feasibility. The need for a reasonable division of rate classes to achieve these goals exists whether the rates are designed based on cost of service principles or some other means.

3. Rate Design Factors

Utility rate design is more art than science. Even within a seemingly objective standard, such as cost of service based rates, there remains considerable latitude for judgment and personal value systems to affect the final result. A leading reference manual on public utility rates goes so far as to state:

> "One of the reasons for the popularity of a cost-of-service standard of ratemaking no doubt lies in the flexibility of the standard itself. 'Cost,' like 'value,' is a word of many meanings, with the result that people who disagree, not just on minor details but on major principles of ratemaking policy, all may subscribe to some version of the principle of service at cost."[1]

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1 Principles of Public Utility Rates by James C. Bonbright, Albert L. Danielsen

The flexibility of the cost of service standard is due to three factors: (1) Matters extraneous to the rate design system; (2) multiple costs to choose from, and (3) the need to allocate or assign costs.

First, it should be recognized that rate design does not occur in a vacuum. The utility likely has an existing rate design which must be considered. Although states prohibit undue discrimination in setting utility rates, the utility's product must compete with alternative energy sources in the marketplace. These and other similar factors will affect the viewpoint and potential results of the rate designer.

Second, there is more than one definition of cost which could be used. There are original costs and replacement costs; fixed costs and variable costs; direct costs and indirect costs; average costs and incremental costs; and short-run costs and long-run costs. Though many options are available, in practice the choice usually comes down to two: (1) allocated costs based upon the existing embedded accounting costs of providing service, and (2) marginal costs reflecting current costs for providing service to new or additional customers. These two approaches are completely antithetical in their philosophy, information used and results. The allocated embedded cost approach is more common, relies on existing accounting data and produces results which permit the utility to earn its authorized return. Marginal cost has a better theoretical foundation, but relies on data not readily available and is more likely to result in over or under-collection.

Once a definition of cost is decided upon, it is then necessary to assign costs to specific customer classes. Generally speaking, these costs can be divided into two broad categories: direct costs and common costs. Direct costs are those which are incurred only to provide service to a particular customer class. Common costs are incurred in providing service to more than one class. The assignment of direct costs is straight-forward and should not be subject to debate. Common costs are another matter. By definition, such costs are incurred for the benefit of several rate classes and their costs cannot be directly assigned. Instead, it is necessary to allocate these costs among the rate classes using some reasonable allocation method. There are a number of reasonable methods which means that the appropriate cost of service allocation is often a hotly contested issue. This is not to suggest that cost of service studies are arbitrary; some allocations are clearly more reasonable than others. However, there is no one correct cost of service, but rather a range of reasonable alternatives. The following two sections present an illustrative cost of study.

B. Historic or Embedded Cost of Service

Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service. Basic load and operating data are needed, in addition to the costs, to conduct a cost allocation study.

Embedded cost of service studies are generally conducted in the following steps: (1) functionalization of costs as either production, storage, transmission or distribution; (2) classification of costs into three basic categories -- customer, energy or commodity, and demand or capacity costs; and (3) the allocation of these costs to customer classes or to types of load. All items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers. There is no scientifically correct method of making necessary allocations. A certain amount of judgment must be used in any cost of service study. Consequently, cost allocation studies should only be utilized as a general guide or as a starting point for rate design.

1. Functionalization of Costs

Functionalization is the arrangement of costs according to major functions, such as production, storage, transmission or distribution. This functional categorization of costs helps to facilitate a determination as to which customer groups are jointly responsible for such costs. Some costs, such as those associated with the general or common plant and administrative and general expenses, generally are not directly assigned to the established functional groups. These costs did not appear to have any direct relationship to the service characteristics employed for purposes of functionalization.

The primary operating functions to which costs can be broadly categorized are described as follows:

Production costs are the costs relating to producing, purchasing or manufacturing gas. Included are purchases of pipeline or producer gas and all costs associated with producing owned or peaking gas; i.e. the gas itself, feedstocks, capital costs, operations and maintenance expense.

Storage costs are the costs associated with storing gas normally during off-peak for use in times of cold weather. Also included are related operation and maintenance expenses.

Transmission costs are the costs incurred in transporting gas from interstate pipelines to the distribution system. Included are the capital costs of transmission mains, as well as city gas metering station costs and related operation and maintenance.

Distribution system costs are those costs incurred to deliver the gas to the customers. Included are capital and operating costs for distribution mains, compressors, customer services, meters, and regulators.

Other costs include those costs that do not fit the above functions, such as the cost associated with common plant and working capital, general and administrative costs, customer accounting, and advertising costs.

The functionalization of costs is generally the easiest step in a cost of service study, since utility investment and expense records are maintained in accordance with prescribed uniform accounting systems. These systems, such as the Uniform System of Accounts, classify costs according to primary operating functions. Thus, the functionalization of costs is already done for the cost of service analyst.

2. Classification of Costs

The functionalization of costs is of limited use in the allocation of costs. Therefore, it is necessary to further classify costs into customer, energy or commodity, and demand or capacity costs.

a. Customer Costs

Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections.

A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand. A calculation of a minimum size main is shown in the illustrative cost allocation study. The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function. Under this basic system theory, only those facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system.

Another controversial item is the inclusion of sales promotion expenses in the customer cost component. Analysts vary in their opinions as to the extent of the inclusion. Some would include all, some none, and some a portion of sales promotion expense in the customer category. With emphasis placed on conservation, many regulatory bodies have prohibited this type of activity, and in those cases, if cost were incurred, it should be deleted from the study based upon its being a "below the line" or a stockholder expense.

b. Energy or Commodity Costs

Energy or commodity costs are those which vary with the quantity of gas produced or purchased. They are largely made up of the commodity portion of purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable expenses used in the production of gas from a manufactured or synthetic gas (SNG) plant. Energy or commodity costs increase or decrease as more or less gas is consumed.

c. Demand or Capacity Costs

Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

3. Allocation of Costs to Customer Classes

After the assignment of costs to the customer, energy, and demand categories, each category must be allocated to the various service classifications or to their subdivisions.

a. Customer Costs

Customer costs may be distributed in proportion to the number of customers in a class, or a more detailed study may be made whereby certain components of the customer costs may be distributed on a per-customer basis, directly assigned or distributed on a weighted per-customer basis. The latter method permits recognition of known or ascertainable customer cost differences such as the frequency of meter readings, complexity in obtaining readings or integrating meter reading charts, and the individiual attention which may be given to large customers, such as separate meter reading schedules.

As discussed earlier, while there may be differences on whether certain items of plant should be assigned to customer costs, there are clearly certain expenses which are independent of whether a customer consumes gas or not. Since these costs will not be recouped if little or no gas is consumed, they are generally included in a minimum bill or customer service charge. One of the useful by-products of a detailed cost of service study is that the customer costs are broken out by service classification or class of customer. When these costs are divided by the number of customers within a particular subdivision, the analyst is provided with an indication of what the minimum or customer service charge should be.

b. Energy or Commodity Costs

Energy or commodity costs may be distributed to customer groups on the basis of the quantity of gas consumed during some historical or projected test period, with or without allowance for losses incurred in transporting the gas from the production plant or city gate station to the customer. If the historical test period were abnormally cold or warm, the sales and related cost should be normalized before allocation. The analyst in reviewing the operation of the system could find that certain classes of customers might appropriately be allocated a greater or lesser than average level of lost and unaccounted for gas. This determination will be affected by such factors as the degree of utilization of distribution facilities, quality of metering equipment and the timing of meter readings relative to purchases.

c. Demand or Capacity Costs

Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry.. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications. As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. Coincident Demand Method

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. Noncoincident Demand Method

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. Average and Peak Demand Method

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of costs between the high and low load factor customers.

5. Use of Load Studies For Allocation of Demand Costs

a. Concepts

As previously mentioned, load data are necessary for a cost of service study. These data are the basis for any demand allocation and, if inaccurate, can give misleading results regardless of the case taken with the remainder of the analysis. The load characteristics of each utility's system and each customer class on a system are unique and must be separately surveyed in each case. The purpose of the survey is to determine for relatively homogenous customer groups such information as load pattern, amount and time of occurrence of maximum load, load factor, and diversity or coincidence factor.

Arriving at load patterns is not an easy task. Most of the necessary information is not readily available from the normal record keeping of a utility. To secure the information requires a systematic activity known as load research. It embraces a whole gamut of engineering, statistical, and mathematical methods and procedures, ranging from the simple application of judgments to available data to refined mathematical probes into the significance of sampling techniques. The gas industry generally has not devoted the same resources to this area in the past as the electric industry on the whole has, so in most cases more reliance will have to be placed on use of existing records than would be preferred. However, since system peaks in the gas industry are highly weather sensitive, a fairly reliable correlation between temperature versus gas consumption can be developed from utility records. By applying a least square fit to "average degree day" and "use per day" data for each customer group, one can calculate with reasonable accuracy the demands to be placed on the system. A relatively unsophisticated estimate of system peaks is included in the illustrative cost of service study.

More attention is now being devoted to this important phase of input data needed for not only studies of this sort, but in understanding customer load profiles in general. The following briefly summarizes the steps which can be taken to develop load curves.

b. Determination of Load Curves By Billing Records

Load curves can be determined for some classes from the billing records of customers who are equipped with standard recording instruments. This is feasible for classes in which all, or nearly all, the customers are so equipped. Normally, this is the case for interruptible and large industrial customers, a tiny fraction of all customers served by a utility.

c. Determination of Load Curves By Load Surveys

The load curves for residential and small commercial and industrial classes must be developed from data for sample groups of these classes, obtained from field surveys, and expanded to include the entire energy use of these classes. The particular procedure adopted will be dictated largely by the economic considerations of conducting such tests and by the availability of manpower and test-metering equipment. However, test groups of sample customers must be carefully selected in accordance with sound statistical principles. The sample customers should be chosen at random so as to properly reflect the specific energy use characteristics of all substantially homogenous customer groups within a service classification.

There may be difficulty in getting customers to accept test meters, since their premises must be available for meter printout sheet or tape replacement where necessary so that the test data will be continuous for the period involved. This complicates the selection procedure.

The selection process must result in a valid statistical sample. Ultimately, there must be selected a representative cross-section of customers willing to cooperate in the test-metering program, sufficiently large in number to be statistically significant. About three times the number of customers for which tests are needed must be initially selected. Factors such as examination of the types of customers produced by the random selection to assure that they are representative; field inspection of premises to determine type of premises; connected load and number of people who live or work on the premises; and unwillingness or inability of a customer to cooperate, all must eventually be tested. A considerable expenditure of time and manpower is needed to complete the process.

C. Illustrative Embedded Cost of Service Study

A cost of service study is a series of choices regarding potentially controversial methods of identifying and allocating costs incurred by a utility. This illustrative study represents one possible means of computing class cost of service. There are many other equally correct methods. For illustrative purposes, the following example demonstrates how the factors discussed above are utilized in a fully allocated cost of service study.

The first step in preparation of the study is a separation of all plant and expense items incurred during the test period into the functional categories of production, storage, transmission, distribution and general. This functionalization is shown throughout the study on Schedules 3, 4 and 5, according to Monopolytown's accounting system. Where possible, functional costs are directly assigned to the classes of service based upon details from the utility's books or by special analysis or studies. This is illustrated in Schedule No. 2 where Rate Revenues are directly assigned to the classes which produce them.

The costs not directly assignable were allocated among the customer classifications according to factors developed from the basic statistical data. The derivation of the allocation factors is illustrated on Schedules 10 and 11. The following is an explanation of the major allocation factors used in this study.

The Peak Day Demand (Allocation Factor 100) is the computed quantity of gas which would be supplied on a day when the mean temperature of the utility's service territory is 5 degrees Fahrenheit (the coldest day in 20 years for this particular system), which equates to a 60 degree-day deficiency. Schedule No. 12 provides the details of the peak day calculations. There are two predominant Commodity allocation factors which consist of normalized and curtailed gas sales during the test period. Factor No. 110 is comprised of sales without transportation volumes. Factor No. 120 is the total throughput quantity which includes gas sales and transportation. The primary Customer allocation factor, No. 160, consists of the number of bills rendered during the test period.

Once the allocation factors are prepared, they should be applied to the functionalized costs in relation to how those costs are incurred by the utility. Expenses and plant are classified or considered to be fixed, variable, customer, or revenue related. Classification is an integral part of the allocation process and once costs are classified, the appropriate allocation factors are applied to these costs as shown in the last column in each of Schedules 2 through 9. Fixed costs are normally allocated on the basis of demand, while variable costs are allocated on the basis of commodity sales. Costs incurred as a result of a customers' connection to the utility system are allocated on the basis of a customer factor, and costs related to revenues are allocated on the basis of a revenue factor. Costs which cannot be related to one of the four basic classifications are allocated on the basis of a composite factor, reflecting two or more elements of the expense or plant accounts. This is illustrated on Schedule No. 4 where account 374 (land and land rights) is allocated on the basis of allocation Factor No. 13, which reflects a composite of the allocation of all other distribution plant.

As a more detailed explanation of the allocation process, consider the allocation of utility plant which is shown on Schedule No. 4. Production plant, which includes a propane-air facility, was designed and constructed by the utility to meet peak load requirements. Consequently, production plant has been allocated on the basis of peak day demand (Allocation Factor No. 100).

The distribution plant investment in mains may be classified as both demand and customer related. The customer component was determine as the amount of investment that would be required it all mains were comprised of a theoretical minimum size. Monopolytown's smallest mains (1.5 inch diameter) were installed at an average unit cost of $0.61 per foot. The customer component of mains is computed by multiplying the total length of mains (6,385,860 feet) by the unit cost of the smallest mains. The resulting amount ($3,988,733) represents approximately 20 percent of the total investment in mains. The remaining 80 percent is considered to be demand related. Therefore, the investment and expenses associated with mains are allocated on the basis of composite allocation Factor No. 150. Factor No. 150 is a weighted average of allocation Factor No. 160 (20 percent weight) and Factor No. 100 (80 percent weight).

Plant facilities such as gas services and meters are allocated to the rate schedules by using allocation factors designed to reflect the various cost differentials among classes. To accomplish this weighted computation for gas services, the typical current cost to construct gas services for each customer class is determined. The class gas service costs are then divided by the typical residential gas service cost. The resulting ratio is a weighting factor which is then multiplied by the number of customers in each class. The product of this calculation then becomes the basis of the gas service Allocation Factor No. 200. The meter allocation factor is determined in a similar manner and the weighting factors utilizied for both meters and gas services are the following:

WEIGHTING FACTORS

Class	Services	Meters
Residential	1	1
*Commercial	5	5
*Industrial	50	40
Interruptible	50	40
Transportation	50	40

* The Commercial and Industrial classes are combined in the study under "GENERAL SERVICE"

Once the allocation of plant is accomplished, depreciation and working capital are the next steps which ultimately lead to the determination of rate base. The allocation of depreciation is illustrated on Schedule No. 5 and the allocation of working capital is demonstrated on Schedule No. 6. The allocation of rate base is illustrated on Schedule No. 7, where figures from previous schedules are assembled to determine customer class rate base for ratemaking purposes.

The allocation of operating expenses is illustrated in Schedule No. 3. Expenses which are demand related, such as pipeline demand charges and gas production expenses, are allocated on the basis of peak day demand, Allocation Factor No. 100. Expenses which are commodity related, such as commodity gas purchases, are allocated on the basis of sales excluding transmission, Allocation Factor No. 110. Customer oriented expenses, such as customer accounting, meter reading and advertising expenses are allocated on the basis of the number of customers on the system or the number of meters, Allocation Factor No. 160 or 180.

Many expenses, such as supervision and engineering, administration and general costs, taxes, and depreciation, are allocated on the same basis as the related plant investment. These are composite allocation factors developed as a line item summary of various elements in the cost of service study as it progresses. For example, Allocation Factor No. 13 is the respective customer class percentage of total distribution plant costs. Therefore, the allocation of any costs which are allocated on the basis of Factor No. 13 would have to proceed after total distribution plant by class is computed on Schedule No. 4. The composite allocation factors are illustrated on Schedule No. 11, with the appropriate reference to their development in the cost of service study.

Following the allocation of all plant and expenses, a summary is developed in Schedule No. 1. The relevent totals from each schedule previously explained are brought forward to Schedule No. 1 as a summary of the cost of service study and to examine the rate of return generated by the entire system as well as each class of service.

MONOPOLYTOWN GAS SERVICES
Summary of Class Cost Study

Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
Total Operating Revenue	62,804,086	30,193,577	21,312,089	11,152,860	145,560	Schedule 2
Operation & Maintenance Exp.	54,131,100	25,396,295	18,595,697	10,070,004	69,104	Schedule 3
Depreciation Expense	1,101,152	716,319	367,692	12,562	4,578	Schedule 5
Federal Income Taxes	1,662,145	800,080	499,938	335,752	26,375	Schedule 9
Taxes Other	2,437,051	1,307,609	795,366	325,151	8,926	Schedule 8
Total Operating Expense	59,331,449	28,220,303	20,258,693	10,743,469	108,983	
Net Operating Income	3,472,637	1,973,274	1,053,396	409,390	36,577	
Charitible Donations	14,080	12,874	1,193	10	3	Factor 170
Interest on Deposits	151,961	139,340	12,621	0	0	Factor 16
Adjusted Net Operating Income	3,306,596	1,821,060	1,039,581	409,380	36,574	
Total Rate Base	24,776,459	14,841,077	8,755,675	1,087,522	92,184	
Return on Rate Base	13.3457%	12.2704%	11.8732%	37.6434%	39.6755%	

MONOPOLYTOWN GAS SERVICES
Allocation of Revenues

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Rate Revenues	62,378,875	29,939,507	21,287,396	11,151,972	0	Direct
487	Forfeited Discounts	235,316	215,166	19,939	167	43	Factor 160
488	Miscellaneous Service Revenue	40,515	37,046	3,433	29	7	Factor 160
489	Transportation Gas	145,510	0	0	0	145,510	Direct
495	Other Revenue	3,870	1,857	1,321	692	0	Factor 17
	Total	62,804,086	30,193,577	21,312,089	11,152,860	145,560	

MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Gas Production Expense	71,759	45,665	26,094	0	0	Factor 100
	Other Gas Supply Expense						
804	Natural Gas Purchases:						
	Demand	7,713,504	4,908,627	2,804,878	0	0	Factor 100
	Commodity	40,424,560	15,870,195	14,369,269	10,185,095	0	Factor 110
805	Synthetic Natural Gas	133,571	85,001	48,571	0	0	Factor 100
805	Propane	59,371	37,782	21,589	0	0	Factor 100
807	Purchased Gas Adjustment	(940,211)	(369,116)	(334,206)	(236,889)	0	Factor 110
809	Gas delivered from storage	50,527	32,154	18,373	0	0	Factor 100
812	Gas used other	(41,664)	(16,357)	(14,810)	(10,497)	0	Factor 100
813	Other expense	13,913	5,462	4,946	3,506	0	Factor 110
	Total Other Gas Supply Exp	47,413,572	20,553,748	16,918,609	9,941,215	0	
	Total Gas Supply Expense	47,485,331	20,599,413	16,944,703	9,941,215	0	
	Distribution Expense:						
	Operation:						
870	Operations super. & engineer.	107,937	80,001	23,149	2,836	1,951	Factor 10
871	Load dispatching	84,742	27,569	24,962	17,693	14,519	Factor 120
873	Compression station fuel	1,111	362	327	232	190	Factor 120
874	Mains	120,979	81,663	39,301	12	3	Factor 150
875	Measuring & regulating general	36,895	23,479	13,416	0	0	Factor 100
876	Measuring & regulating indust.	13,761	0	3,237	5,781	4,743	Factor 140
878	Meter & house regulators	369,766	234,693	125,915	7,289	1,869	Factor 180
879	Customer installation	552,732	506,824	45,908	0	0	Factor 170
880	Other distribution expense	287,109	212,801	61,575	7,544	5,189	Factor 10
881	Rents	5,248	3,890	1,126	138	95	Factor 10
	Total Operating Expense	1,580,280	1,171,282	338,916	41,525	28,558	

MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Maintenance Expense:						
885	Supervision & engineering	24,228	15,115	8,078	627	409	Factor 11
886	Structures & improvements	36,408	11,844	10,724	7,601	6,238	Factor 120
887	Mains	231,598	156,333	75,237	23	6	Factor 150
888	Compressor station equipment	17	6	5	4	3	Factor 120
889	Measuring & regulating general	81,770	52,036	29,734	0	0	Factor 100
890	Measuring & regulating indust.	7,177	0	1,688	3,015	2,474	Factor 140
892	Services	107,644	68,322	36,656	2,122	544	Factor 180
893	Meters	120,421	76,432	41,007	2,374	609	Factor 180
894	Other	1,341	837	447	35	23	Factor 11
	Total Maintenance Expense	610,604	380,925	203,575	15,800	10,304	
	Total Distribution Expense	2,190,885	1,552,206	542,491	57,324	38,863	
	Customer Accounting Expense:						
901	Supervision	58,268	53,279	4,937	41	11	Factor 160
902	Meter reading expense	255,409	162,110	86,974	5,034	1,291	Factor 180
903	Customer records	1,171,530	743,578	398,938	23,092	5,921	Factor 180
904	Uncollectible expense	248,489	227,212	21,056	176	45	Factor 160
905	Miscellaneous expense	29,838	27,283	2,528	21	5	Factor 160
	Total	1,763,535	1,213,463	514,433	28,366	7,273	
	Customer Services Expense:						
909	Miscellaneous expense	768	702	65	1	0	Factor 160
909	Advertising expense	2,740	2,537	201	2	0	Factor 160
	Total Customer Service Expense	3,508	3,239	266	2	1	

MONOPOLYTOWN GAS SERVICES
Allocation of Operating & Maintenance Expense

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Sales:						
915	Supervision	153,026	139,923	12,967	109	28	Factor 160
916	Selling	178,241	162,979	15,103	127	32	Factor 160
917	Advertising	112,431	102,804	9,527	80	20	Factor 160
918	Miscellaneous	24,556	22,453	2,081	17	4	Factor 160
	Total	468,253	428,158	39,677	332	85	
	Administrative & General Exp.:						
920	Administrative & gen'l salary	722,334	521,748	179,004	14,039	7,543	Factor 12
921	Office supplies	271,907	196,401	67,382	5,285	2,839	Factor 12
922	Administrative expense	(49,554)	(35,793)	(12,280)	(963)	(517)	Factor 12
923	Outside services	444,917	321,368	110,257	8,647	4,646	Factor 12
924	Property insurance	14,353	9,340	4,786	166	61	Factor 13
925	Injuries & damages	65,744	47,487	16,292	1,278	687	Factor 12
926	Employee pension & benefits	675,923	488,225	167,503	13,137	7,059	Factor 12
928	Regulatory commission expense	4,431	3,201	1,098	86	46	Factor 12
930	Miscellaneous general expense	36,214	26,157	8,974	704	378	Factor 12
931	Rents	33,319	21,682	11,111	386	141	Factor 13
	Total Administrative & General	2,219,588	1,599,815	554,127	42,764	22,882	
	Total Operating & Maintenance	54,131,100	25,396,295	18,595,697	10,070,004	69,104	

MONOPOLYTOWN GAS SERVICES
Allocation of Plant in Service

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Intangible:						
301	Organization	52,036	33,862	17,352	603	220	Factor 13
302	Franchises	47,068	30,628	15,695	545	199	Factor 13
	Total	99,104	64,490	33,047	1,148	418	
	Manufactured Production:						
304	Land & land rights	26,375	16,784	9,591	0	0	Factor 100
305	Structures & improvements	65,825	41,889	23,936	0	0	Factor 100
311	Liquefied petroleum	387,373	246,512	140,861	0	0	Factor 100
320	Other equipment	429	273	156	0	0	Factor 100
	Total	480,001	305,457	174,544	0	0	
	Distribution Plant:						
374	Land & land rights	94,527	61,512	31,521	1,095	399	Factor 13
375	Structures & improvements	213,046	138,636	71,043	2,468	899	Factor 13
376	Mains	19,326,453	13,045,703	6,278,354	1,907	489	Factor 150
377	Compressor station equipment	66,327	42,208	24,118	0	0	Factor 100
378	Measuring & regulating general	724,502	461,050	263,452	0	0	Factor 100
385	Measuring & regulating indust.	181,941	0	42,797	76,428	62,715	Factor 140
380	Services	9,361,448	5,828,366	3,248,811	226,256	58,014	Factor 200
381	Meters	2,621,018	1,663,579	892,528	51,664	13,247	Factor 180
382	Meter installations	1,215,649	771,581	413,961	23,962	6,144	Factor 180
383	House regulators	638,684	405,377	217,489	12,589	3,228	Factor 180
384	House regulator installations	320,403	203,362	109,106	6,316	1,619	Factor 180
386	Other property	2,799	2,559	237	2	1	Factor 160
387	Other equipment	23,304	15,165	7,771	270	98	Factor 13
	Total	34,790,101	22,639,100	11,601,189	402,957	146,855	
	Total General Plant	1,423,053	926,029	474,535	16,483	6,007	Factor 13
	Total Plant in Service	36,792,259	23,935,076	12,283,315	420,588	153,280	

MONOPOLYTOWN GAS SERVICES
Depreciation

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Accumulated Depreciation:						
108	Production	9,383	5,971	3,412	0	0	Factor 100
108	Distribution	8,299,182	5,400,559	2,767,465	96,126	35,032	Factor 13
108	General	791,723	515,201	264,010	9,170	3,342	Factor 13
108	Total	9,100,288	5,921,731	3,034,886	105,296	38,374	
	Depreciation Expense:						
403	Production	16,552	10,533	6,019	0	0	Factor 100
403	Distribution	989,011	643,583	329,798	11,455	4,175	Factor 13
403	General	95,589	62,203	31,875	1,107	403	Factor 13
403	Total	1,101,152	716,319	367,692	12,562	4,578	

MONOPOLYTOWN GAS SERVICES
Allocation of Working Capital

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
165	Gas inventory	867,715	552,186	315,529	0	0	Factor 100
151	Synthetic feedstock	95,249	60,613	34,636	0	0	Factor 100
154	Materials & supplies	438,742	285,504	146,304	5,082	1,852	Factor 13
131	Cash	4,572,355	2,145,179	1,570,745	850,595	5,837	Factor 19
168	Cost free capital	(3,686,585)	(2,398,086)	(1,231,228)	(41,974)	(15,297)	Factor 16
	Total Working Capital	2,287,476	645,396	835,986	813,702	(7,608)	

MONOPOLYTOWN GAS SERVICES
Allocation of Rate Base

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Net Plant:						
	Total gas plant	36,792,259	23,935,076	12,283,315	420,588	153,280	Schedule 4
	Total accumulated depreciation	9,100,288	5,921,731	3,034,886	105,296	38,374	Schedule 5
	Net plant	27,691,971	18,013,345	9,248,428	315,292	114,906	
	Working Capital	2,287,476	645,396	835,986	813,702	(7,608)	Schedule 6
	Net Plant	27,691,971	18,013,345	9,248,428	315,292	114,906	
282	Deferred taxes	(3,580,574)	(2,330,001)	(1,193,986)	(41,472)	(15,114)	Factor 13
235	Customer Deposits	(1,622,415)	(1,487,663)	(134,752)	0	0	Factor 170
	Rate Base	24,776,459	14,841,077	8,755,675	1,087,522	92,184	

MONOPOLYTOWN GAS SERVICES
Allocation of Taxes Other Than Federal Income Tax

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
408	Federal unemployment insurance	9,955	7,191	2,467	193	104	Factor 12
408	FICA & miscellaneous tax	307,736	222,280	76,261	5,981	3,214	Factor 12
408	State unemployment insurance	6,031	4,356	1,495	117	63	Factor 12
408	Property tax	339,937	221,209	113,356	3,937	1,435	Factor 13
408	Gross receipts tax	1,512,583	727,187	513,284	268,607	3,506	Factor 14
408	Franchise tax	96	46	33	17	0	Factor 14
408	Business & occupation	260,712	125,339	88,471	46,298	604	Factor 14
	Total Taxes Other	2,437,051	1,307,609	795,366	325,151	8,926	

MONOPOLYTOWN GAS SERVICES
Allocation of Federal Income Tax

Acct	Description	System ($)	Residential ($)	General ($)	Interrupt ($)	Transport ($)	Allocation
	Total Operating Revenue	62,804,086	30,193,577	21,312,089	11,152,860	145,560	Schedule 2
	Operation & maintenance exp.	54,131,100	25,396,295	18,595,697	10,070,004	69,104	Schedule 3
	Depreciation expense	1,101,152	716,319	367,692	12,562	4,578	Schedule 5
408	Taxes other	2,437,051	1,307,609	795,366	325,151	8,926	Schedule 8
729	Charitable deductions	14,080	12,874	1,193	10	3	Factor 160
730	Interest on deposits	151,961	139,340	12,621	0	0	Factor 170
731	Interest expense	1,087,043	707,110	363,045	12,377	4,511	Factor 16
	Miscellaneous deductions	269,364	175,218	89,961	3,067	1,118	Factor 16
	Total Expense	59,191,751	28,454,765	20,225,576	10,423,171	88,239	
	Taxable Income	3,612,335	1,738,812	1,086,513	729,689	57,321	
	Total Federal Income Tax	1,662,145	800,080	499,938	335,752	26,375	Factor 20

MONOPOLYTOWN GAS SERVICES
Allocation Factors

Fact	Description	System	Residential	General	Interrupt	Transport
100	Peak Day	85,053	54,125	30,928	0	0
		100%	63.64%	36.36%	0.00%	0.00%
110	Sales without Transporation	10,228,227	4,015,479	3,635,714	2,577,034	0
		100%	39.26%	35.55%	25.20%	0.00%
120	Sales with Transportation	12,342,893	4,015,479	3,635,714	2,577,034	2,114,666
		100%	32.53%	29.46%	20.88%	17.13%
130	Residential & Commercial Sales	6,208,137	4,015,479	2,192,658	0	0
		100%	64.68%	35.32%	0.00%	0.00%
140	Sales without Residential &	6,134,756	0	1,443,056	2,577,034	2,114,666
	Commercial	100%	0.00%	23.52%	42.01%	34.47%
160	Customers	54,936	50,232	4,655	39	10
		100%	91.44%	8.47%	0.07%	0.02%
170	Number of Residential &	54,782	50,232	4,550	0	0
	Commercial Customers	100%	91.69%	8.31%	0.00%	0.00%
180	Meters	79,142	50,232	26,950	1,560	400
		100%	63.47%	34.05%	1.97%	0.51%
200	Services	82,415	50,232	28,000	1,950	500
		100%	60.95%	33.97%	2.37%	0.61%
150	Mains 20% on Customers, 80% on	79,030	53,346	25,673	8	2
	Demand	100%	67.50%	32.49%	0.01%	0.00%

MONOPOLYTOWN GAS SERVICES
Derivation of Composite Allocators

Factor 10 - Composite of Accounts 871 through 879

Factor 11 - Composite of Accounts 886 through 893

Factor 12 - Composite of Total Production & Distribution O&M Expense less Gas Costs

Factor 13 - Total Distribution Plant

Factor 14 - Total Revenue

Factor 16 - Composite of Net Plant

Factor 17 - Rate Revenue

Factor 19 - Total Operating & Maintenance Expense

Factor 20 - Total Taxable Income

MONOPOLYTOWN GAS SERVICES
Derivation of Peak Day Demand

		Residential	Commercial	Industrial
7		Residential	Commercial	Industrial
8	January Usage	14.13 Mcf/Cust	76.07 Mcf/Cust	1504.11 Mcf/Cust
9	Non-Heating Load a_/	1.94 Mcf/Cust	14.61 Mcf/Cust	991.84 Mcf/Cust
10	Heating Load (line 8 - line 9)	12.19 Mcf/Cust	61.46 Mcf/Cust	512.27 Mcf/Cust
11				
12	January Degree Day Deficiences (DDD) b_/	707	724	979
13	Peak Day DDD	60	60	60
14				
15	Heating Use Per Degree Day c_/	0.0172 Mcf/Cust	0.0849 Mcf/Cust	0.5233 Mcf/Cust
16				
17	Peak Day Heating Use (line 15 * line 13)	1.0346 Mcf/Cust	5.0934 Mcf/Cust	31.3956 Mcf/Cust
18	Peak Day NonHeat Use (line 9 / 30.4)	0.0639 Mcf/Cust	0.4807 Mcf/Cust	32.6264 Mcf/Cust
19	Peak Day Use (line 17 + line 18)	1.0985 Mcf/Cust	5.5741 Mcf/Cust	64.0220 Mcf/Cust
20				
21	Number of Customers	49,273	4,331	106
22				
23	Peak Day Usage (line 19 * line 21)	54,125 Mcf	24,141 Mcf	6,786 Mcf
24				
25	Calculated Peak Day Demand (Sum line 23)	85,053 Mcf		

a_/ Assumes non-heating load equals average daily usage during the summer.

b_/ Monthly DDD varies for each class as a result of cycle billing.

c_/ Peak month heating usage divided by total peak month degree day deficiencies (DDD).

Note : The Commercial and Industrial peak day usages are used to determine the peak day allocation factor for the General rate class.

E. Rate Design

1. Firm Rates

Most of a utility's customers will be firm customers; that is, they have no alternate fuel or energy source readily available. The fact that they are firm customers indicates that the utility has an obligation to serve them and the utility plans its gas supply acquisition program and its system capacity with the goal of maintaining service to these cutomers.

Firm rates could be designed using any of the rate forms discussed in Chapter I, but most commonly use a flat rate or a declining block rate.

When flat rates are used, they normally consist of two components, a customer charge (or minimum bill) and a flat commodity rate. Even though the cost of service study indicates how to allocate costs to classes, it still must be decided how much of this cost to recover with each of these two rate components. First, customer charges should be billed as an explicit, separate, monthly charge. Ideally, the customer charge should recover all customer costs. However, to the extent that customer costs are not fully recovered in the customer charge or that capacity costs are included, the customer charge will be above or below customer costs. In some jurisdictions, an explicit customer charge will be unacceptable. In this case, a minimum bill, extending over a few units of gas, is an alternative. The commodity costs allocated to the class divided by normalized sales will yield the commodity component of the rate.

The most controversial issue is deciding where capacity costs belong in the rate. Because they are fixed costs, it is sometimes argued that they should be part of the customer charge. On the other hand, it can be argued that gas not customer backup, is the fundamental product being sold, and that those common fixed costs should be recovered evenly from all units of commodity sold. It is even occasionally proposed that these costs be spread between customer and commodity charges. On an embedded cost basis, once the decision is made as to what revenues should be collected through the customer charge, that amount is subtracted from the revenue requirement. All other revenues needed to meet the total revenue requirement must then be recovered through the commodity portion of the rate.

If instead of fixed customer charges and flat commodity rates, declining block rates are used, the initial high-priced blocks usually reflect the fixed costs of customer service as accurately as possible. Also, since gas sales are generally temperature sensitive, the tail blocks normally contain only a small amount of fixed costs. This provides revenue stability during abnormal weather.

2. Inverted/Lifeline/Baseline Rates

Lifeline and inverted rates are many times thought of interchangeably but there can be major differences between them. For instance, lifeline rate structures are almost always inverted but an inverted rate structure may not be a lifeline rate. The difference arises because of philosophical reasons and value judgments which pervade the entire rate design process.

The lifeline rate is a social rate design which has as its goal the furnishing of a quantity of gas sufficient to meet the basic energy needs of certain residential customers at a subsidized rate. The quantity of gas in the initial block could vary according to geographical location and season of the year, if it is intended to cover space heating needs. Winter volumes would have to be sufficient to cover space heating, water heating and cooking loads, while summer basic gas requirements would include only the latter two.

The rate charged for the initial block should not be less than the variable system cost, principally the commodity cost of gas, and depending upon the amount of subsidy, may or may not pick up some of the system's fixed cost. The cost not picked up in the initial residential block is spread to larger residential customers in higher usage blocks (an inverted rate) and to all commercial and industrial customers. Because of the subsidization, legislation may be needed before lifeline rates can be implemented to avoid claims of undue discrimination.

Another approach sometimes used to eliminate concerns with undue discrimination is to make a baseline rate available to all residential customers and have no cost shifted to commercial and industrial customers. Unlike the concept of lifeline rates wherein eligibility depends upon social or economic factors, a baseline rate would be universally applicable to all residential customers' essential needs service.

Inverted rate designs generally were advocated to encourage conservation and utilize marginal cost principles to foster that goal. Thus, lower rates per unit of gas are charged in the initial, nonelastic blocks and progressively higher rates per unit of gas are charged in the more elastic end blocks.

Under lifeline, baseline or inverted rate structures, the ability of a utility to earn its revenue requirement is riskier than with a declining block rate structure. This is because rates are designed to recover a large amount of fixed costs through the tail block rates which depend upon usage that is more sensitive to conservation and weather.

3. Interruptible Rates

Interruptible rates are designed with the primary purpose of controlling load factor. Interruptible service is offered by a gas utility to an industrial or commercial customer without an obligation to deliver any specific volume. The volume of gas available is determined by supply or dispatching considerations. Interruptible sales fill the summer valleys created by the heating load.

Traditionally, interruptible rates have been designed for customers with alternate fuel capability. With the onset of gas transportation, many of these customers have converted from sales to transportation. Consequently, with respect to the recovery of gas costs, the impact of interruptible customers on a utility's load factor is no longer as significant as it once was.

4. Seasonal Rates

Prior to the early 1970s, utilities attempted to maintain high system load factors to reduce unit gas costs. This was typically accomplished by means of either underground storage or interruptible sales (including some service just provided during the off-peak season) or a combination of both.

Subsequent to the early 1970s, curtailments became an important feature of the national supply picture. Utilities no longer received all the pipeline gas contracted for, and service to some types of firm customers was interrupted or permanently abandoned. Utilities began to acquire high cost supplemental gas and increased storage and peaking capabilities to ensure that winter demand was met. These activities so altered the economic cost relationship between summer and winter gas that much more significant cost differentials existed.

FERC Order 436 and the subsequent opening up of the natural gas market to competitive market forces have done two things to place renewed emphasis on seasonal rates. First, Order 436 requires that open access pipelines have transportation rates with seasonal differentiation. Second, the spot market for natural gas has shown a strong seasonal differentiation in price. While the long-term effects of this open gas market are not now known with any clarity, it is reasonable to expect that these differentials in well-head gas costs and transportation costs may ultimately result in seasonal distribution rates which reflect these cost differentials.

5. Demand or Standby Rates

A customer may wish to use some fuel source other than system supply gas as his primary fuel and use that gas only as a backup. This is convenient for the customer because he can easily shift to system supply gas on short notice if the service line and delivery equipment are in place. However, the utility may be required to provide the same delivery services that it would for its other customers, as well as maintain an available gas supply for a customer who will seldom, if ever, use it.

The service being provided here is not so much gas supply as it is the availability of a backup fuel source. Charging rates based on traditional rate design would be unreasonable in these instances. The customer would generate very little commodity revenue. Accordingly, the rate should be designed to recover, through a demand or standby charge, the costs associated with maintaining that backup, including the costs of the delivery system and the cost of maintaining a gas supply to provide backup.

6. Flexible Rates

Traditionally, utility rates have been set at a fixed amount which cannot be varied by the utility absent a rate order from the Commission. This system worked fine as long as natural gas prices were substantially below those of oil.

However, about 1983, gas prices rose and oil prices fell to the point at which significant gas sales began to be lost to oil through price competition. When this happened it became clear that the inflexibility of gas prices allowed oil dealers to reduce their prices to just below the fixed gas price and gain a competitive advantage. The solution to this problem was to set flexible rates allowing the utility to vary its price between a floor and a ceiling. The use of flexible rates results in three main issues which must be addressed.

First, the rate must be designed to avoid undue discrimination. Fixed rates provide that all customers within a given rate class will be charged the same rate and hence do not provide a discrimination problem. However, with flexible rates, different customers in the same rate class can be charged different rates. Whether this would be undue discrimination will depend upon the specific law in a given state. If there are discrimination concerns, they can be alleviated by a number of methods, including: (1) requiring that all customers in the rate class receive the same rate; (2) grouping customers in a rate class by some characateristic (such as existence or type of alternate fuel) and requiring that all customers in the group be charged the same; and (3) setting the rate for each customer at the price at which the customer could obtain an alternate fuel.

The second issue involves the method of setting the floor and the ceiling. Sometimes a floor is not used if the utility is responsible for absorbing all losses caused by downward reduction in the rates. Where a floor is used it should not be set below the short-run variable cost of providing service, because there is no valid economic theory to support a rate below this level; moreover, such a floor guards against challenges based upon predatory pricing and anti-trust considerations. The setting of a ceiling rate is much more difficult than deciding on a floor. Often times the ceiling is set at the fully allocated cost of service as determined by the cost of service study. However, this has the disadvantage of causing the average rate to be below the fully allocated cost unless all sales are at the ceiling. Another common approach is to set the ceiling such that the expected average cost equals the fully allocated cost. A third alternative is to set the ceiling as far above the fully allocated cost as the floor is below that cost. Whatever approach is used, it is quite likely to draw attention simply because there is no wholly satisfactory method for setting the ceiling.

The third issue to be considered is the method for pricing sales on flexible rate for the purpose of meeting the revenue requirement. With fixed rates, this process is normally straight-foward as the revenues are simply the rate times the sales volume. With flexible rates, the exact rate itself is unknown. The problem is compounded by the fact that the sales units may be a function of the rate actually charged, with lower rates producing higher sales and vice-versa. One approach is to use the ceiling rate on the theory that the utility will only discount from the ceiling when it is in the utility's best interest to do so and the utility should be responsible for any revenue loss caused by discounting. Another approach is simply to assign a target revenue that the utility should be expected to achieve. Mathematically this has the same effect as allocating a certain level of costs to the class. Finally, if the functional relationship between sales and rates is known, sales can be priced at the rate which maximizes revenues.

7. Incentive Rates

Another rate form that has been used is related to circumstances where a utility is attempting to either capture a new load or recapture a load previously serviced with natural gas. The basis for this rate is the relationship of current consumption to a selected base year where the load was not serviced by the gas utility. All consumption in excess of the base volume would receive a discount from the normal tariff rate. The discount, or incentive, could take the form of a percentage of full tariff, possibly with step discounts for increased consumption or it could take the form of a stated flat rate. In either instance, the customer would continue to purchase base volumes at the full stated tariff rate, and all incremental consumption would receive the discount. Implementing such a rate does present potential discrimination problems. Depending upon the magnitude of the discount the utility could be providing service to customers with similar characteristics at widely divergent rates. Such a situation, particularly if the customers were competitors and energy was a significant element of their cost of goods sold, could be unduly discriminatory.

F. Other Factors

1. Historical Rates

The utility's currently existing rate structure and the history of changes in that structure should be considered when a new rate design is contemplated. If the existing structure works reasonably well, there will likely be considerable reluctance to change it. Even when there is convincing evidence that major changes are needed, Commissions will often utilize the concept of gradualism to make a series of small incremental changes rather than a large revolutionary change. Rate design changes which can be postured as improvements on the existing system are more likely to find acceptance because they maintain continuity and minimize problems due to misunderstanding.

2. Social and Political Factors

By its very nature, the ratemaking process is subject to considerable public and political scrutiny. Commissioners are either appointed by elected officials or are elected themselves. The Commission itself is typically a creature of the Legislature -- created for a specific purpose and existing until dissolved by the Legislature. While the ratemaking process is designed to be somewhat insulated from direct political pressure, nevertheless political influence does affect the process. Broad governmental policy goals, such as business climate development, can have a significant impact. While such policies may not directly determine the final result, it would probably be undesirable to set rates which directly controvert such a policy.

Consideration also needs to be given to designing rates which are responsive to the social needs of our society. Like political factors, social factors are nebulous and ill-defined, but not unimportant. In practice, it is often difficult to distinguish between social and political factors.

It is probably impossible to give any hard and fast rules for incorporating social and political factors into utility rate design, and no attempt will be made here. Suffice to say that rate designers should be aware of the social and political implications of their work. Gas rate design is not an abstract application of economic principles, but rather a practical exercise which affects customers in their daily lives. The rate designer should be aware that people need affordable gas to heat their homes and businesses need energy supplies which enable them to remain competitive. The rate designer should be sympathetic to these concerns while continuing to follow the basic rate design principles.

Chapter III - Rate Based on Value of Service

A. Basic Concepts

1. Alternate Fuel Competition

Up until this point, rates have been considered to be based on the principle of cost, giving recognitition to the fact that there is no one definition of cost, and that other factors (social, political, historical) may have some effect. At this point we set aside cost-of-service to the customer as a standard and consider a totally different one--value of service to the customer.

There is even less agreement on the definition of value of service than there is on cost of service. Obviously the value referred to is the value to the customer. From this, one might infer that value of service pricing is tantamount to deregulation of a monopoly, wherein the utility raises its price to the highest level that the customer will pay. However, this concept of value of service has seldom, if ever, been used.

Most commonly, value of service in the natural gas industry has been determined by reference to the cost of alternate fuels available to the customer. Although large industrial customers have a wide variety of alternate fuels available to them, the marginal alternative is generally taken to be No. 6 residual fuel oil. While coal may be cheaper in the long-run, a choice to use it involves a substantial capital investment and thus it is not the type of short-term alternative with which gas competes. Other alternatives are generally more expensive, and thus the Btu-equivalent price of residual oil is normally taken to be the measure of the value of service for a large industrial customer.

Surprisingly, value of service pricing has been used as a standard for industrial customers during periods of shortage and surplus, although the reasons for doing so were different. During the natural gas shortage of the 1970's, prices were escalating at a rapid pace as efforts were made to raise well-head prices in order to provide additional supplies of natural gas. By the late 1970's and early 1980's residential prices had risen to the point that many customers were having difficulty paying their bills. At the same time, indus-dustrial gas prices were low relative to the cost of residual fuel oil, which had an inflated price caused by the actions of the OPEC oil cartel. Consequently, many Commissions raised industrial rates based on the cost of alternative fuels and used the additional revenues to lower residential rates and soften the "rate shock" hitting those customers. This was a case of value of service pricing being used to foster a social ratemaking goal.

By the middle of the 1980's, things had changed dramatically. Oil prices had fallen due to the world-wide glut while natural gas prices had generally continued upward. For industrial customers, gas prices set on a cost of service basis exceeded the alternate fuel price, and utilities began to lose industrial load. In this environment, Commissions once again turned to value of service pricing, in this case to maintain markets that would otherwise be lost.

2. Competition Due to Bypass

Natural gas utilities have long been considered to be natural monopolies. This concept forms the basis of utility regulation. Gas utilities have their rates and conditions of service regulated and in turn they receive protection from competition. In many states, this protection comes in the form of exclusive franchises, where the utility has the right (and the obligation) to provide service and other utility competition is prohibited.

Even though the states have the right to regulate entry of other local gas distributors, this does not necessarily mean that an individual state commission can restrict market entry of an interstate pipeline performing transportation service. Each Commission's authority depends upon the specific laws under which it operates. If a state does not have an exclusive franchise system or there is bypass by a pipeline, there may be no alternative method of dealing with bypass other than rate design.

An important step in dealing with a potential bypass situation is to make a decision as to whether the customer is worth keeping. Distribution utilities and interstate pipelines have different characteristics, with different strengths and weaknesses. Utilities may have an obligation to serve and hold themselves out to all applicants for service. They also maintain large distribution networks to serve a wide area. An interstate pipeline may only have a short service extension to serve an individual industrial customer. Because of these differences, it may not be possible for the utility to continue serving the customer at rates competitive with the pipeline, and still cover the utility's variable cost and make a contribution to fixed cost.

If rate design is to be used in an effort to prevent bypass, then it will be necessary to determine why bypass is attractive to the customer. Utility rates are normally set based on the average cost to serve all similarly situated customers. This means that customers' rates are based on average costs for many types of items, such as average distribution main, average uncollectibles, average lost and unaccounted for, etc. An interstate pipeline may be able to take advantage of a customer's specific situation. For example, if the customer is located adjacent to an interstate pipeline's main transmission line, the pipeline may be able to serve the customer at a cost below that of the distributor. In such cases, devising a special rate for the distributor which takes into account the unique characteristics of the customer may be the only way to compete. If a special rate is not adequate, then this may be a case of economic bypass which should be allowed to occur.

In dealing with the threat of bypass, non-price factors can be important elements to consider. The customer may have had a long-term relationship with the utility, which could be the source of goodwill. There may be some price security in staying with the utility since its rates are regulated by the state commission. On the other hand, the pipeline's direct industrial sales rates are not regulated by FERC. In the case of interstate transportation, FERC regulates the transportation rates and service but not the sales price. Finally, if the utility receives supplies from more than one pipeline, it may be able to offer greater supply reliability to the customer.

As with most rate design issues, in dealing with bypass, it is important to keep in mind the objectives to be achieved. Bypass may be undesirable because the loss of large industrial customers means that the remaining customers will bear a greater share of the utility's fixed costs. It is reasonable to make pragmatic rate design decisions to offer reduced rates to potential bypass customers, provided that the customer maintains a reasonable contribution to the system fixed costs. If this cannot be done, then such economic bypass situations should probably be allowed to proceed.

B. Competitive Rates

1. Rate Determination

Setting rates based on value of service bears little relationship to setting them based on cost of service. When the cost of service system is used, the rate is built up from the various cost elements incurred by the utility. The rate becomes the sum of those costs which are assigned to the customer's rate class.

When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer. This can be the Btu-equivalent cost of an alternative fuel or the cost of a competing gas source, but it can also represent non-fuel alternatives. For example, if a firm is in danger of going bankrupt and gas represents a significant cost to the company, then it may be desirable to design rates with a goal of keeping the firm operating. Similarly, if industrial customers have the option of producing at different locations, it would be prudent to consider setting gas rates at a level which would encourage maintaining production locally. This is especially true when a new business is considering moving into the area. It is increasingly common to offer reduced rates to such customers to induce them to choose to locate in the utility's service territory.

2. Maximum - Minimum or Flexible Rates

Maximum - Minimum or Flexible rates have already been discussed in Chapter II, where they were considered as a development of rates based on cost of service. That discussion applies equally well to their use in setting rates based on value of service, except that some additional matters should be discussesd.

Flexible rates are more common and more properly suited to use with value of service principles. Rate setting is not simply a matter to be determined by calculation from formula, but rather there is a zone of reasonableness within which utility rates may fall. Rates below that zone are confiscatory and do not give the utility an opportunity to earn its authorized return. Rates above the zone are monopolistic. Any rate within the zone is generally considered to be just and reasonable, so long as it is not applied in an unduly discriminatory fashion.

The use of a zone of rates with a ceiling and floor often comports well with the objectives of value of service pricing. Value of service is most commonly used when there is a need to meet competition from a substitute fuel. Determining the appropriate competitive price can be difficult for two reasons. First, it is not always easy to determine the equivalent price of an alternate fuel. One must take into account not only the Btu equivalency, but other costs associated with the alternative such as installation and maintenance of equipment, fuel storage, payment upon delivery, inventory maintenance and costs associated with burning a less clean fuel. Second, the costs of alternative supplies can change quickly and unpredictably. Consequently, even if the competitive rate were well-known at any point in time, it could change so rapidly that such a price would be ineffective for meeting competition.

Flexible rates alleviate both of these concerns. Obviously if the prices of alternate fuels change, flexible rates permit rapid adjustment to meet these changing circumstances. Less obviously, flexible rates reduce the need to precisely measure the equivalent cost of an alternate fuel. If sales are lost due to failure to properly consider some factor in converting costs from the alternate fuel to gas, then this is readily correctable with flexible rates. Traditional rates would remain in place until the Commission could act to change them. Flexible rates provide the opportunity to utilize feedback received from the market to move towards the appropriate competitive rate. Some protection against abuse may be necessary because such rates also provide the opportunity for the end-user to utilize the rate system and threat of competition to obtain a lower rate than they otherwise would pay.

3. Contribution to Fixed Costs

Although value of service is an alternative to setting rates based on cost of service, the decision to use value of service as the basis for designing rates does not mean that costs can or should be ignored. Costs must still be considered when using value of service, but the nature of the analysis changes.

Costs for a utility (or any other corporation) can be divided into two categories: fixed and variable. Fixed costs do not materially change with the volume of output (units of gas sold or number of customers). Variable costs do change with the volume. In actual practice, the dividing line between fixed and variable costs is not sharp and clearly defined. However, in the short run, which is normally the period of concern for the rate designer, most costs can reasonably be categorized as either fixed or variable. Generally, a reasonable classification can be made by looking to see if a given cost would be avoidable in the near future (say two or three years) if output were to decline significantly.

When using a cost of service approach to design rates, the distinction between fixed and variable costs may not be significant. Under this approach, the objective is to allocate costs among rate classes, without regard to whether the costs are fixed or variable. When using value of service pricing, the distinction between fixed and variable costs becomes crucial.

Fixed costs are going to be incurred regardless of whether a given sale is made or not. They must be recovered either from the utility's customers or from its shareholders. Variable costs are going to be incurred only if a given sale occurs. This sets a floor on value of service pricing. That is, the rate should be set to recover the utility's variable cost of service at a minimum. The rate has some positive benefit if it recovers the variable cost and provides some contribution to the recovery of the utility's fixed cost. This raises two important questions: (1) How much contribution is appropriate; and (2) what happens if that amount is not recovered?

The first question is easier to deal with. Generally value of service pricing is used when competitive market conditions do not permit charging a rate which recovers the fully allocated cost of service. From this it follows that the rate should at least be designed to recover as much of the fully allocated fixed cost as possible. Although in theory the rate would be beneficial with any amount of fixed cost coverage, it is common to set some minimum amount that would be considered reasonable.

Because markets are competitive, the ability to recover any level of fixed costs is problematic. Since there is risk associated with the failure to recover a given level of fixed costs, absent a Commission policy the rate designer must deal with the issue of how to allocate this risk. There are two choices: the other ratepayers and the shareholders. The answer is not easy and is primarily a value judgment. On the one hand, it is argued it is reasonable that shareholders bear the risk because the utility has an obligation to control its costs and remain competitive. On the other hand, the argument is that the utility is a regulated entity which must be given a reasonable opportunity to earn its authorized rate of return. Both arguments have merit, and the rate analyst must make a judgment between them in setting rates if the Commission does not already have an existing policy on this issue.

C. Market Segmentation

1. Ability to Maximize Revenues

The use of market segmentation to maximize net revenues is a common one in many industries. To be able to segment the market efficiently, two conditions must be met: (1) the customers are divisable into two or more classes which have different elasticities of demand, and (2) the product can be sold separately to each class without an effective means for one class to resell the product to another.

Market segmentation can best be explained by example. Consider a local movie theater which has 200 potential customers. Of these, 100 are adults who would be willing to pay up to $4 per ticket, while 100 are children who will only pay $2 each. The movie theater could set its price at $4 and generate $400 in revenue ($4 x 100 customers), or it could set the price at $2 and receive $400 ($2 x 200 customers). What the theater will probably attempt to do is segment the market by offering a matinee priced at $2 to attract the children and an evening show at $4 for the adults. If successful, this strategy will generate revenues of $600 ($2 x 100 children plus $4 x 100 adults).

The gas industry provides many opportunities to use market segmentation. There is little chance that one customer will be able to resell his service to another. There are a wide variety of customers with differing characteristics and demand. The traditional method of dividing customers into rate classes is one example of market segmentation, although its goal is not necessarily revenue maximization when rates are based on cost of service.

When value of service concepts are used, market segmentation can be a valuable tool to maxmimize revenues and the fixed cost contribution from such customers. Under these circumstances, the customers will normally have differing competitive price levels depending upon their type of alternate fuel, and possible other factors. By classifying customers into different groups according to their cost of alternatives, the rate design can reduce the proportion of fixed costs which will be borne by other customers.

2. Discrimination and Price Differentiation

Although the specific laws vary from state to state, the general rule is that gas rates be free from undue discrimination. The requirement that rates shall be free from undue discrimination does not mean that the rates be the same for all services and customers. What it does mean is that differing rates for differing customer groups must reasonably reflect differences in their conditions of service. Generally, there are two such differences: (1) differences in cost, and (2) differences in competition. Obviously, when value of service pricing is being used, the first matters not. With respect to the second, the rate designer should ensure that the classification of customers reflects differing competitive conditions and that the differences in rates reasonably reflect those differing conditions. For example, if the cost of propane and distillate fuel oil were approximately the same it would probably be discrimination to charge significantly different rates to customers with one or the other of these alternate fuel capabilities.

Another concern regarding discrimination is the need to ensure that the rates set for customer classes, that have little or no alternate fuel source available, are fair. The value of service to that captive customer class is very high. Protection from monopolistic pricing becomes a function of regulation, not competition.

D. Special Rates

Special rates may be developed to recognize unique customer circumstances, promote economic development and provide incentives for the development of certain natural gas usages. These rates are often subject to allegations of discrimination and represent a departure from traditional ratemaking. Special rates may be prohibited by certain regulatory commissions or state law. Customer specific rates, economic development rates and incentive rates are examples of special rates.

1. Customer Specific Rates

Customers whose load characteristics differ significantly from any other customer groups or customers whose physical connection to the utility is unique may require special rates. Examples of these unusual circumstances are: extremely large customers with loads that represent a significant percentage of their respective distribution utility's load; customers served directly from a transmission main; or customers who have made a significant contribution in aid of construction. Typical customer groupings or rate schedules may not recognize these unique situations and may result in inequitable treatments. In these instances it may be necessary to develop a separate rate schedule or rate blocks within a rate schedule to recognize the special customer.

2. Economic Development Rates

Economic development rates are designed to promote growth within a gas distribution utility's service area. These rates seek to attract new customers through discounts from the otherwise applicable tariff rate. These discounts may be eliminated over time. For example: an economic development tariff may provide new customers with a 15 percent discount during the first year; a 10 percent discount during the second year; a 5 percent discount during the third year; and no discount thereafter. Economic development may also be promoted by liberal line extension policies and customer connection requirements.

Another, more controversial, example of an economic development rate is one that reflects the incremental cost of providing the new service with no contribution toward the costs associated with the utility's existing system. These incremental costs are limited to the investment and expenses associated directly with the new service. This type of economic development rate is generally limited to very large customers and usually result in a customer specific rate. Pre-existing customers often argue that these incrementally based rates are preferential and should be made available to all customers.

3. Incentive Rates

Incentive rates are designed to promote specific types of usages which provide operational or economic benefits. One such rate, gas-fired air conditioning, provides a discount for summer usage. Increased summer usage is often beneficial as a result of increased utilization of purchased demand volumes and improved cash flow. Natural gas distribution utilities typically have excess capacity during the summer months since their loads are primarily heat sensitive.

Many gas utilities are actively promoting incentive rates for gas-fired cogeneration. Cogenerators may provide significant economic benefits to the utility as a result of their large natural gas usage and high load factor. The economies of scale associated with these large users and the potential operational benefits allow gas utilities to offer attractive cogeneration rates for both sales and transportation services.

Chapter IV Cost of Gas Adjustments

A. Importance of Gas Costs and Effect on Cost of Service

The marketing of natural gas as a consumer commodity is accomplished in a regulatory environment that inhibits the marketer's freedom to use competitive skills and pricing factors. This regulatory environment exists at both the federal and state level. Marketers must offer their product at an inflexible tariff rate set and approved by regulatory agencies.

For the distributor, commodity cost makes up fifty to eighty percent of the sales tariff. The obvious need for some flexibility to adjust to swings in their gas purchase cost has mandated the approval and adoption of a "Purchase Gas Adjustment" (PGA) rider to their approved tariffs.

At the federal level, currently, interstate pipelines are encouraged to act primarily as transporters of gas for distribution systems and end-users that have been, or are currently, purchasers under inflexible tariffs. The various components of transportation tariffs are all cost of service items, with the commodity cost the concern of the distributors and end-users. As this transformation progresses, the cost of gas will become of lesser importance to interstate pipelines. Total replacement of marketing services will never occur, however, since a number of distribution systems and end-users will, through their own choice, continue reliance on the pipeline as a supplier of natural gas. For these remaining purchasers, the pipeline must get approval of a set tariff, and, like the distribution system which must gain regulatory approval of sales tariffs, must contend with the monthly swings of their weighted average cost of gas.

B. Pipeline Rates

1. Natural Gas Act, Natural Gas Policy Act, and FERC

Prior to the mid-1980's, local gas distribution companies (LDCs) generally purchased most of their needed gas from interstate gas pipelines "system supply gas." Stated differently, the interstate pipelines functioned primarily as merchants, buying gas from a large number of producers and reselling the aggregated gas supply to LDCs as well as other customers. The role of most interstate pipelines is changing (more rapidly for some than others) from that of being primarily a gas merchant to becoming more of a gas transporter, offering sales and other services on a "unbundled" basis.

The changing role of interstate gas pipelines and changes in the regulations affecting those pipelines have a direct impact on the types of services available to LDCs and the charges for those services. To best appreciate the reasons for and implications of some of the changes, a brief overview of some essential points of interstate gas pipeline rates is appropriate.

All rates and charges related to the transportation of natural gas in interstate commerce and the sale for resale of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission (FERC). The FERC's authority in this regard derives principally from its administration of the Natural Gas Act of 1938 (NGA). This statute continues to be the "cornerstone" of the Federal Government's regulation of interstate natural gas facilities and activities.

Another Federal statute affecting natural gas activities (including some intrastate, as well as interstate activities) is the Natural Gas Policy Act of 1978 (NGPA). Among other things, all "first sales" of natural gas, such as sales by a gas producer to an interstate or intrastate gas pipeline or to a local distribution company (LDC), are controlled by the operation of this statute. While the NGPA gradually deregulated many types of first sales, some such sales are still subject to either or both price controls under the NGPA or certificate jurisdiction under the NGA. Some transportation of gas is also subject to rate jurisdiction under the NGPA, as is discussed later.

The NGPA, like the NGA, is administered by the FERC. However, the implementation of certain functions under the NGPA requires assistance from state and other regulatory agencies.

For example, "well category determinations," which involve decisions as to whether a particular well qualifies for a specific pricing category under the NGPA, are made by state and other "jurisdictional agencies." Such determinations are subject to review by the FERC; but the reviews are limited, essentially, to the adequacy of the record on which the determinations were made.

Also, certain transportation rates by an intrastate pipeline for transporting gas on behalf of an interstate pipeline or an LDC served by an interstate pipeline are authorized by the FERC if the rates have been previously approved by and are on file with a state regulatory agency. The NGPA requires FERC's approval of such rates because the nature of the transportation services involved, by definition, causes the gas to become involved in interstate commerce.

The above noted types of transportation services by intrastate pipelines were provided for under the NGPA as a means of integrating intrastate pipelines and gas supplies with interstate markets. In this way, a truly integrated, national pipeline grid system was created, which allows for more efficient use of facilities and more efficient allocation of natural gas resources. The NGPA is clear, however, that Federal regulation under the NGA does not extend to intrastate activities conducted under the NGPA.

2. Standards for Reviewing Pipeline Rates

The standards employed by the FERC for reviewing rates differ depending on the "type" of rate involved. The standards also differ somewhat depending on whether the service involved is related to activities authorized by the FERC in administering the NGA or activities conducted under the NGPA.

For example, when an interstate pipeline receives authority from the FERC to perform a "new service" or to change an existing service, such authorization derives from section 7 of the NGA. This part of the NGA deals with the issuance of certificates of "public convenience and necessity."

Rates approved under section 7 of the NGA are called "initial rates." Typically, such rates cannot be based upon any historical cost and operation experience, because none exists. Therefore, such rates are based more on projections of future costs and operations.

The FERC uses its "conditioning authority" under section 7 of the NGA to attach any conditions it deems necessary to assure that an "initial rate" will remain consistent with the overall public interest until it is subsequently reviewed under section 4 or section 5 of the NGA. An applicant has to notify the FERC within 30 days from the date a certificate is issued whether the applicant accepts the certificate. This notification is required, irrespective of whether the FERC imposes a "rate condition' or any other condition in issuing the certificate.

An interstate pipeline is, of course, free to propose changes to its existing rates. Section 4 of the NGA establishes the essential authority for the FERC's review of such rate changes. Section 4(a) and (b) state:

> (a) All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the [FERC], and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.
>
> (b) No natural-gas company shall, with respect to any transportaiton or sale of natural gas subject to the jurisdiction of the [FERC], (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Section 5 of the NGA allows the FERC to review an interstate pipeline's existing rates, even where those rates were found to be appropriate during a previous review process (under, for example, either section 7 or section 4) and the pipeline proposes to continue the effectiveness of those rates. In pertinent part, section 5(a) states:

> (a) Whenever the [FERC], after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the [FERC], or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the [FERC] shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: ...

Although the NGA does not define the term "just and reasonable," the FERC and the reviewing courts have generally held that actual cost-of-service has to be viewed at least as the point of departure in determining whether the "just and reasonable" standard is satisfied. Any departure from cost-of-service must be justified by demonstrating a "public interest purpose." The courts have made clear, however, that the FERC is permitted to select any rate which is within a "zone of reasonableness."

The courts have also held that the FERC is not bound to the use of any single formula or combination of formulae in determining rates. And the courts have recognized that ratemaking involves the making of pragmatic adjustments. At the bottom line, it is the result reached -- and not the ratemaking method employed -- that is controlling in determining whether the "just and reasonable" standard is satisfied. (Ref: FPC v. Hope Natural Gas Co., 320 U.S. 591, 600-01(1944)).

The NGPA required some modifications to certain of FERC's ratemaking approaches used under the NGA. For example, section 601(c) of the NGPA prohibits the FERC from denying an interstate pipeline from recovering the costs of gas purchased at prices established by the NGPA -- except to the extent the FERC determines that the amounts paid were "excessive due to fraud, abuse, or similar grounds." Thus, the FERC's ability to deny the flow-through in a pipeline's rates of the prices paid for gas purchased by the pipeline is somewhat limited by the NGPA.

The FERC can, however, examine a pipeline's overall gas purchasing practices as a part of its "prudence review process" under the NGA. Thus, although the NGPA intentionally "shields" the well-head prices that the

U.S. Congress determined to be consistent with the national interests, the pipeline remains accountable for its contracting practices and its management of gas supplies.

A pipeline is also accountable for its contracting practices and prices paid for gas that is price-deregulated under the NGPA. Although the test can be somewhat subjective, the "bottom line" is whether the pipeline's overall gas contracting and purchasing practices are "prudent."

The standards for reviewing transportation rates also differ somewhat under the NGPA, as compared to the NGA. As explained earlier, the essential review standard under the NGA is a determination of whether the overall effect of a rate is "just and reasonable." Also as noted, the courts and a long history of FERC orders (including orders issued by its predecessor agency, the Federal Power Commission) have constructed a strong nexus between rates referenced to "rate-base cost-of-service" and the "just and reasonable" standard.

Section 311 of the NGPA adopts the NGA's "just and reasonable" standard for rates applicable to NGPA-related transportation by interstate pipelines. This approach maintains consistency in the manner in which rates are determined for transportation conducted by interstate pipelines, irrespective of whether the transportation is related to the NGA or the NGPA.

By contrast, the NGPA employs a "fair and equitable" standard for rates applicable to transportation by intrastate pipelines. This standard, among other things, permits the FERC to authorize the use of intrastate pipeline rates which have been approved by a variety of state regulatory agencies, possibly using somewhat differing approaches to setting rates.

Therefore, the FERC could determine that a rate approved by a state regulatory agency satisfied the "fair and equitable" standard under the NGPA, even where the method used to compute the rate would not totally conform to the original cost-of-service methodologies used to set a "just and reasonable" rate under the NGA for an interstate pipeline. However, section 311 of the NGPA also makes clear that any charges by an intrastate pipeline "may not exceed an amount which is reasonably comparable to the rates and charges which interstate pipelines would be permitted to charge for providing similar transportation service."

As is set out in detail in the FERC's regulations, rate authorization for transportation performed by an intrastate pipeline can be obtained in several ways. The FERC's authorization is, essentially, automatic if the transportation rate is equal to "the cost of gathering, treatment, processing, transportation, delivery or similar service (including storage service) included in one of [the intrastate pipeline's] then effective firm rate schedules for city-gate service on file with the appropriate state regulatory agency." Authorization is also, essentially, automatic if the transportation rate is equal to the allowance permitted by an "appropriate state regulatory agency" to be included in an LDC's rates for city-gate service.

Rate authorization may also be obtained if the intrastate pipeline uses a transportation rate which is on file and in effect with the "appropriate state regulatory agency." However, the intrastate pipeline has to demonstrate to the FERC that such a rate covers service comparable to the service to be performed under section 311 of the NGPA.

In authorizing such a rate, the FERC exercises its authority under section 502(c) of the NGPA. Under this authority, the FERC grants "adjustments, states that the amounts paid by an interstate pipeline to an intrastate pipeline for any transportation authorized by the FERC under Section 311(a) of the NGPA are deemed just and reasonable (for purposes of setting the interstate pipeline's rates) if such amounts do not exceed that approved by the FERC.

Taken together, the above concerns and ratemaking approaches are intended to provide safeguards against shifting the cost effects of any underutilized facilities and inefficient operations to interstate gas customers. At the same time, however, rate certainty remains in place (after rates are approved under these procedures) for the intrastate pipeline providing the NGPA Section 311 transportation service and for the interstate pipeline purchasing this service.

As developed above, and terminology aside, the same essential public interest considerations are inherent to both the "just and reasonable" standard under the NGA and the "fair and equitable" standard under the NGPA. And, as noted earlier, the guiding ratemaking precept involved is the propriety of the result reached -- and not the methodology employed -- in determining whether the overall public interests are sufficiently accounted for.

3. Interstate Pipelines' PGA Rates

Before the 1980s, an interstate pipeline's costs of purchasing gas increased generally in proportion to increases in regulated well-head prices. After the NGPA initially came into play this feature generally continued, although the NGPA gradually eliminated many of the well-head price controls.

Pipelines were able to reasonably forecast their gas cost increases, based upon known increases in well-head ceiling prices and estimates of the mix of various "pricing categories" of gas and price-deregulated gas available to the pipeline. Thus, pipelines were permitted to adjust the "gas supply" component of their rates, generally every six months, to accomodate these cost changes.

The above procedures, generally referred to as "PGA filings," were permissable and not mandatory. In a sense, the PGA procedures provided administrative conveniences -- for the regulators and the pipelines' customers, as well as for the pipelines.

Changes in gas markets, caused primarily by interfuel competition and gas-to-gas competition, made the past PGA procedures inefficient. This inefficiency arose because the normal operation of FERC's PGA regulations did not permit pipelines to make timely rate adjustments to meet competition their markets.

However, where justification was shown, the FERC waived the PGA regulations to permit pipelines to make "out-of-cycle" PGA filings. Generally, this procedure permitted pipelines to make PGA filings more frequently or on dates other than those prescribed by FERC's regulations.

Also, downwardly flexible PGA procedures were approved by the FERC for specific pipelines that requested them as a means of addressing competition. Under the flexible PGA procedures, the pipeline could (after a one-day notice) reduce its rates below its last-approved "base PGA gas rate."

Downwardly flexible PGA procedures were approved by the FERC as a means of permitting timely adjustments to be made to the gas component of a pipeline's rates. Approval was based on the belief that these procedures offered the opportunity for benefits for both the pipeline and its customers. However, the FERC made clear that flexible PGAs were not to be used as a "marketing tool," to the disadvantage of certain of a pipeline's customers.

In particular, the FERC was concerned that flexible PGAs not be used by a pipeline to defer recovery of a substantial amount of its purchased gas costs to a subsequent period, or to allocate "unrecovered" costs to a customer or class of customers not benefitting from these procedures. To guard against these possibilities, pipelines were not permitted to recover any "deferred" gas costs in excess of 3 percent of their projected gas costs, absent a specific showing that such costs should be recovered.

To permit pipelines to better deal with the growing competition in natural gas markets, the FERC established new PGA regulations, which became effective on May 1, 1988. These new regulations provided for one comprehensive annual PGA filing and for three quarterly filings, which shortened by one-half the normal prescribed time between filings under the previous PGA regulations.

Shortening of the interval between PGA filings was intended to offer more rate flexibility for the pipeline. It was also intended to reduce the dollar amounts by which a pipeline could under-recover its purchased gas costs between consecutive PGA filings and, in turn, reduce the amount of carrying charges (interest) that would be imputed to such imbalances.

The new PGA regulations carried forward the requirement that a pipeline separately state the level of purchased gas costs (i.e., its "base PGA gas rate") incorporated in its overall charges. This feature better informs the pipeline's existing customers and potential customers of the effects of their decisions in dealing with the pipeline. The new PGA regulations also permitted on a generic basis the "flexible PGA procedures" noted above.

In essence, the new PGA regulations recognized the growing competition in natural gas markets and the need to provide for greater rate flexibility to deal with this increased competition.

4. Demand-Commodity Rates

The PGA rate changes described above generally occur more frequently than other types of pipeline rate changes. Therefore, they are probably the most familiar type of rate changes made by interstate pipelines. However, rate changes related to the non-gas component of pipelines' charges are equally important.

As was noted in regard to FERC's policies affecting the gas component of pipeline charges, FERC's policies affecting the non-gas component of interstate pipelines' charges also significantly changed during the mid and late 1980s. The need for these changes was due to the growing competition in natural gas markets, as was noted earlier. Some of the changes relate to generally familiar ratemaking features; other changes were more profound.

Most interstate gas pipelines have two-part rate structures, composed of a demand charge and a commodity charge. The demand charge may be split between a peak or daily component and an annual component, as is the case under the Modified Fixed Variable rate design noted later.

Generally, the demand charge applies to the level of "firm" service that the LDC (or other customer) has contracted for. In a sense, the LDC has reserved the right to "demand" service up to this level of service -- on a daily, seasonal, or annual basis, as the case may be.

The pipeline's commodity charge applies only to the actual quantities of service purchased by the LDC. That is, the LDC is not assessed commodity charges for quantities not purchased; neither is the LDC required to purchase a minimum quantity of gas. Although "minimum commodity bills" were typically a part of gas pipeline tariffs in the past, they are no longer permitted under the FERC's regulations.

Moreover, "fixed-cost minimum commodity bills" (which would, essentially, assure the pipeline's recovery of fixed costs classified to its commodity charges) are also generally disallowed by the FERC under the currently employed rate procedures, for reasons noted in the following discussion.

Generally there has been agreement that all of a pipeline's variable costs should be recovered by its "usage" (commodity) rates; however, the method of classifying a pipeline's fixed costs has been somewhat controversial and has changed over time.

During the mid-1980s, the FERC's use of the Modified Fixed Variable (MFV) rate design approach was fairly well established. However, this rate design replaced the earlier used Seaboard and United rate designs. The differences in these several rate design methodologies relate primarily to the relative proportions of a pipeline's "fixed costs" that would be classified between its usage (commodity) and demand rates under each method.

By definition, fixed costs remain essentially constant (at least over the short term); also, they are not materially affected by changes in facilities utilization or gas throughput. Fixed costs include labor expenses, overhead costs, and capital-related costs -- such as plant investment, depreciation accrual, debt expense, return on equity capital, and associated income taxes.

Capital-related costs (depreciation, debt expense, equity return, and income taxes) normally make up the preponderance of a pipeline's fixed costs.

These costs are often referred to as being "capacity-related," or as "capacity" costs. This association exists because of the obvious direct relationship between these costs and a pipeline's physical capacity to provide services.

Because a regulated pipeline must have a reasonable opportunity to recover its full cost-of-service, including a reasonable return on its investment, the rate design employed can, among other things, affect the degree to which a pipeline's recovery of fixed costs (and especially capacity-related costs) are exposed to pipeline performance. Of course, this feature is not the only goal, nor necessarily the most important goal, of ratemaking; however, it's particulary relevant to gas pipeline ratemaking in an evolving more competitive environment.

The <u>Seaboard</u> formula, commonly used for designing pipeline rates until the early-1970s, made an equal division in classifying storage and transmission fixed costs between demand and commodity. That is, 50 percent of these fixed costs were recovered by the pipeline's demand charges and 50 percent were recovered by its commodity charges.

By the mid-1970s, the <u>United</u> formula replaced the <u>Seaboard</u> formula for designing rates for most pipelines. Under the <u>United</u> formula, 25 percent of a pipeline's storage and transmission fixed costs were classified to demand and 75 percent were classified to commodity.

Under both the <u>Seaboard</u> and <u>United</u> formulas, all of a pipeline's fixed "production" costs (e.g., gathering facilities costs) would be classified to the commodity charges. Costs related to services purchased from another interstate gas pipeline would be classified between the purchasing pipeline's

In addition to the above required 36-month base tariff review filings, an interstate pipeline is free to unilaterally make "general rate change filings" with the FERC. Such filings were especially common during past periods of major pipeline expansions or during periods of declining markets. However, with increasing stability in the extent and configuration of pipeline systems, the need for these types of rate filings is less now than in earlier periods.

With changes in natural gas markets, brought about primarily by a clear Congressional intent to phase out the wellhead regulation of natural gas and to eliminate the separate interstate and intrastate markets, the frequency and nature of rate change filings by interstate pipelines should continue to change in the furture. Some of these changes are briefly discussed next.

5. <u>Seasonal/Storage Rates</u>

With the growth in competition in natural gas markets during the 1980s, the FERC undertook significant changes in the regulation of an interstate pipeline's services and charges. These various changes, and other changes in regulatory policies, were espoused particularly in FERC's Order No. 436 and Order No. 500. Some of these changes are briefly discussed below; these changes and other features of Order Nos. 436 and 500 are discussed more fully in Chapter V.

Order Nos. 436 and 500 had several principal purposes. One purpose was to "unbundle"pipeline services, and especially transportation from other services. Another purpose was to provide more rate flexibility to the pipeline so it could remain competitive, while at the same time making the pipeline more accountable for its decisions and actions.

The essential public interest purpose of these orders was that with the unbundling of pipeline services, LDCs and other gas purchasers would be offered a wider variety of gas suppliers and gas services. Thus, they would be freer to purchase gas directly from producers, marketers, and other suppliers and contract separately with pipelines for transportion and other needed services. In this way, a variety of suppliers and pipelines could compete for various portions or all of the purchasers' needs.

Order Nos. 436 and 500 do not, however, preclude an LDC from continuing to purchase all of its needed gas supplies and services from its historic pipeline supplier. Rather, they permit the LDC to select a portfolio of suppliers and services that best suits its short-term and longer-term requirements.

If a pipeline were to offer its basic services on a completely "unbundled" basis (in addition to continuing to offer some "bundled" services), the LDC could make better informed decisions regarding the most economic and reliable means of meeting its needs for natural gas services. The LDC would have some indication of the pricing and other terms of each service. As such, the LDC would know the full cost of the menu of services (e.g., gathering, storage, transportation, gas supply, etc.) chosen to bring various gas supplies to its markets, as well as the probable reliability of these services.

These changes could, however, cause the LDC to make choices it did not have to make in the past. For example, some (but not all) gas pipelines have offered or proposed "seasonal sales services." Such services allow an LDC to contract for a higher level of service during its peak-demand period than for other periods. Generally, the charge for seasonal sales service would be expected to equate to the pipeline's costs for off-peak service plus an incremental component to compensate the pipeline for storage and other costs attributable to service.

Also, some pipelines have offered "contract storage services," which generally are contracted for by LDCs having significant flucuations between peak and off-peak requirements. Normally, contract storage service is available in only specific storage fields or specified portions of the storage capacity in certain fields. As such, the costs of this service can be separated from a pipeline's overall cost-of-service and directly assigned to those customers which have contracted for specific levels of storage service.

Generally, the pipeline's contract storage service incorporates maximum limits on the quantities of gas a customer can place into and withdraw from storage. These limits are usually defined on both a daily basis and a seasonal basis; and, in effect, these quantities establish the extent of the customer's contractual right to "demand" storage capacity.

Like charges for transportation capacity, charges for storage capacity are assessed through the pipeline's demand rates. Separate charges (similar to a commodity charge) are also normally assessed for the actual quantities of gas injected into and withdrawn from storage for the account of a customer. Generally, these charges are composed of 100 percent variable costs and do not recover any fixed costs.

The cost classification and rate design procedures used to develop a pipeline's contract storage demand rates generally followed the same procedures used to develope that pipeline's transportation rates when the Seaboard and United rate designs have been employed. However, as the MFV formula is normally implemented, a slight variation exists.

Under the MFV rate design approach, all fixed storage costs (including return on equity and associated income taxes) are classified as demand costs. These demand costs are then divided equally between a storage "deliverability" charge and a storage "space" charge.

The storage deliverability charge is assessed on the basis of a customer's daily storage entitlement, and the storage space charge is assessed on the basis of the customer's seasonal entitlement to receive this service. This treatment more closely accounts for the relative costs responsibilities attributable to and among contract storage service customers (versus customers that have not contracted for this specific service) than would result from the same MFV procedures used to design the pipeline's transportation rates.

Some or all of the storage capability on some pipeline systems has not traditionally been offered as a distinct "contract storage service." Rather, it has been viewed as being integral to the pipeline's transportation facilities, services, and charges.

As currently implemented, Order Nos. 436 and 500 would require that an interstate pipeline segregate its transportation and storage charges. Any storage-related costs included in a pipeline's transportation charges would be permitted only on the basis that the storage facilities that engendered the costs were: (1) integral to the pipeline's gas transportation system, (2) provided a benefit to the transportation service, and (3) were available to customers contracting for gas transportation service.

Under past ratemaking approaches, storage costs have generally been included in the non-gas component of most pipelines' rates. Typically, such treatment was based on the view that the existence and use of storage facilities resulted in more efficient transportation, lower costs of transportation facilities (because of smaller size pipe or less compression, or both), and lower charges for transportation services.

The propriety of continuing the past treatment of storage costs will likely be challenged for many pipelines. Such challenges -- as well as challenges to the inclusion of gathering costs in transportation rates and to some of the other more traditional ratemaking approaches -- are likely to continue during the transition from the past periods of rigid regulatory approaches to ratemaking to the more flexible, unbundled ratemaking provided by the FERC's Order Nos. 436 and 500.

C. Adjustment Clauses

1. Historical Costs

Prospective tariffs of necessity require an assumption of prospective gas costs. Like hindsight, historical cost is suggested to be the most reliable source of data from which this assumption can be made. Use of "zero-basing" in tariff design would not require any such assumption.

2. Formulistic Methods

Using an historical cost as the base cost in tariffs allows for a billing amount to which can be added or subtracted a calculated difference per Mcf sales unit that adjusts to latest known costs.

The calculations are made through use of a PGA formula that, in simplest form, dictates A - B = PGA, where "A" is the current (latest known) cost per Mcf, "B" is the embedded tariff (base) cost, and the difference is the PGA factor as applied to sales volume.

This simple formula obviously does not recover the cost of unaccounted for volumes, unless the cost-of-service element of the tariff contains line loss recovery of a determined percentage at base cost. In this case, the assuming line loss is constant, i.e. experienced the same as the tariff provision, the simple formula corrects base cost to actual cost only on the sales volumes. The tariff recovery is set, and does not change. Monetary gain or loss is minimal to the extent gas cost swings are not abnormally great.

This formula does not, however, recover the base cost of the unaccounted for gas whenever the tariff element of cost-of-service does not contain provision for line loss. The formula may be adjusted as various regulatory agencies authorize full recovery of gas costs or, to encourage greater maintenance and deliveries, authorize recovery of only portions of total gas cost attributable to line loss. On the other hand, there is a PGA formula which can deal with recovery for unaccounted for volumes. This formula is A - B divided by 1 - x, where the component x is the line loss experienced.

Some regulatory agencies also authorize a surcharge to "true-up" the PGA revenues collected, since the PGA factor is based on purchase volumes and then is applied to sales volumes. This surcharge methodology, known as "Deferred Fuel Cost Accounting," establishes the dollar amount of PGA recovery authorized, nets this to amount collected, and charges the difference into a balance sheet deferred account. Periodic accumulations (normally one to twelve months) are then divided by the estimated or forecasted sales volumes for the recovery period (again, one to twelve months), to arrive at the surcharge to be used.

End-of-period remaining balances are brought forward into the next recovery period.

3. <u>Forecasted Gas Costs</u>

Actual gas cost for any given billing period is not known, except in smaller distribution systems where that information is available from the supplier at the same time the end-user meters are read. The latest known cost per Mcf is accepted by most regulatory agencies for PGA purposes. Forcasted gas cost may in some states be used for tariff development (base cost), but a general policy or pattern for such use in the PGA is not discernable from contacts with other state regulatory agencies.

4. Allocation of Gas Costs

The revenue collection from a utility's PGA surcharge may be allocated based on at least two considerations. First, such revenue may be allocated according to customer class. In this instance, such allocation may be equivalent for all such classes, or some classes may be paying more PGA revenue than others. Unequal PGA charges may result from factors such as: (1) special sales programs for industrial end users; (2) off-system sales and/or transportation revenue credits; (3) serving large capacity end users as transporter for their gas rather than as a utility supplier of gas to the end user; (4) end users choosing to operate with the utility on an interruptable basis where only changes in the commodity component of a pipeline's rate structure might be reflected; and (5) class load factor differences. Second, PGA revenue may be allocated according to regulatory areas of jurisdiction. Some utilities, for example, operate in more than one state and thus utilize two or more PGA clauses, based on the requirements of each jurisdiction. Since these PGA clauses may vary in both form and content, their impact in terms of cost on customers' bills may also vary.

D. Gas Purchasing Practice Reviews

The industry and regulation have allowed gas utilities to expand their involvement into the nontraditional method of acquiring gas supplies and thereby establishing a portfolio approach to gas purchasing. As a result, state regulatory agencies have become more concerned about the lengths of contracts, price of gas, reliability of supply, mix of supply and other issues not previously reviewed in depth by many state regulatory bodies.

Some states chose to incorporate this expanded review into the rate case proceeding, other states chose to expand the Purchase Gas Adjustment (PGA) review and others established separate reviews.

While some states chose to establish formal rules on information the utilities should provide the state agencies and what criteria will be considered in determining if their purchasing practice are acceptable, other states decided to wait.

Forecasting requirements is one of the areas many states are reviewing. The typical time covered in the forecasting requirements are five to ten years but many range from one to twenty years. Some states require that not only the volumes of gas to be used but expected prices, sources, storage use and other applicable information be provided for review.

Procurement plans and practices are also being reviewed by some states. These states require the utilities to provide the gas contracts and the review of the contracts may range from informal to full blown examinations.

The procurement plans of the utilities are required by some states and these may be reviewed in rate case proceedings or separate formal proceedings.

Chapter V - Transportation Rates

A. Nature of Transportation Versus Sales

Traditionally, natural gas utilities and their supplying pipelines have bought and sold gas supplies for their own account - commonly referred to as the merchant function. Under this function, the utility performs the following operations: (1) contract for natural gas supplies from a pipeline or producer, (2) take delivery of the supplies into the utility's system, (3) transmit the gas through the utility's integrated transmission, distribution and storage system, and (4) deliver the gas to the customer upon demand. These four operations occurred without the need for the customer to do anything other than turn on the customer's gas-burning equipment when it was needed.

In recent years, many customers have begun to conduct the first operation themselves (contracting for their own gas supplies), while relying on the utility for operations 2 through 4. This approach -- commonly referred to as transportation -- became a viable option during the middle 1980's when customers were able to negotiate for gas at prices lower than available from the local utility. As a result, customers who were capable of negotiating their own gas supply contracts, found transportation to be an economically attractive option.

From an operating point of view, transportation differs very little from traditional sales for a utility. The most important difference is that the utility need not contract for gas supplies for the transportation customer. It is not clear whether this is an advantage or a disadvantage, since the transportation option complicates the planning for gas supplies by the utility. The only other substantial difference is that transportation complicates the billing procedure due to the need to track individual supplies for individual customers from the wellhead to the burner-tip.

B. FERC Order 436/500

Federal regulation of interstate transportation can be conveniently divided into three types: (1) traditional transportation under the Natural Gas Act, (2) transportation under Section 311 of the Natural Gas Policy Act, and (3) open access transportation under FERC Order 436/500.

The Natural Gas Act (NGA) of 1938 provided for regulation by the Federal Power Commission (now Federal Energy Regulatory Commission) over the interstate transportation and sales of natural gas. Under this act, FERC has broad rate-making powers with respect to interstate gas sales-for-resale and transportation, as well as certificate authority. Any natural gas company seeking to engage in the transportation of gas in interstate commerce must first obtain a certificate of public convenience and necessity from FERC. To obtain this certificate, the pipeline has to demonstrate that it is able and willing to perform the service and to conform to FERC's rules and regulations, and that the proposed service is or will be required by the present or future public convenience and necessity. Otherwise the application is denied. These certification provisions effectively function to restrict access to transportation services. When a pipeline files for a certificate to serve an area with an existing competing pipeline, the competitor will normally file a protest alleging that the service is unneeded. When this happens, the matter is set for hearing, which may eventually result in the pipeline being permitted to provide transportation service, but only afater completing a long and tedious certification process.

This process fit in well with the regulatory scheme of the NGA, which was premised on the assumption that pipelines were natural monopolies. It was thought in 1938 that the pipelines were not subject to workable competition and thus should be restricted in the exercise of their monopoly power. As a quid pro quo, new entry into the market was restricted by the certificate process.

By the middle 1980's the natural monopoly assumption was no longer universally valid. Pipelines were subject to competition from a variety of sources, including other pipelines, locally produced gas, alternate fuels and conservation. Rather than being able to use their monopoly powers to coerce customers, pipelines often found themselves in situations where regulation tied their hands and prevented them from competing effectively.

FERC Order 436 was an effort to respond to these changed circumstances by permitting pipelines the freedom to compete within the framework of the NGA, that had been altered in some important aspects by the Natural Gas Policy Act of 1978 (NGPA). In essence, the NGPA eliminated or placed into effect a phase-out of most Federal regulation of gas at the well-head. It provided impetus for the transportation of natural gas. Order 436 allowed a pipeline to choose between continuing to provide service under the traditional NGA certification procedure, or to become an open access transporter, which provides for more flexibility but puts the pipeline at risk if it fails to compete successfully. Pipelines, who become open access transporters, are required to provide non-discriminatory access to all shippers. The pipeline must offer both firm and interruptible service, and within each category must provide service on a "first come -- first served" basis.

Order 436 also contained certain contract reduction rights for local distribution companies. The reviewing court found that FERC had not adequately dealt with the take-or-pay problems being experienced by the pipelines and that the contract reduction provision in Order 436 could exacerbate the problem. Consequently the court remanded the proceeding to FERC. The court did, however, generally uphold the basic concept embodied in Order 436. In response, FERC issued Order 500 which left the basic transportation provisions intact.

The main difference between sales rates and transportation rates is that transportation rates are "unbundled" while sales rates are not. A sales customer pays a rate which includes all services provided by the utility. By definition, a transportation customer does not use all of those services, since the custmer contracts for its own gas supplies, and therefore transportation rates should be unbundled to pay for only those services provided to the transportation customer directly or indirectly.

The first issue to be decided is what qualifications should be met for a customer to go on transportion. There can be serious problems associated with allowing essential needs customers (such as hospitals) to become transportation customers without backup supply. Transportation customers normally have a limited number of suppliers (often only one) and run the risk of supply shortage if their supplier is unable to deliver. It may be unacceptable public policy to allow essential needs customers to be without an adequate gas supply. There are many methods for dealing with this concern. One possibility is to allow only interruptible customers with alternate fuel capability to go on transportation. Some states divide customers into an esssential needs or core group which must remain on sales, and a non-core group which has an option to switch to transportation. Others use a monthly administrative fee as a fence to keep smaller customers off transportation. Some states require transportation customers to execute an affidavit certifying their gas procurement plans. While a variety of methods are available, the important point is that the particular method chosen should be selected with the utility's supply plan in mind.

Once the qualifications for transportation have been determined, the next step is to design rates. Four methods have been developed for setting transportation rates: (1) Net margin, (2) Gross margin, (3) Allocated cost of service, and (4) Value of service.

Net margin is a method of deriving transportation rates from a utility's existing sales rates. Under this method, the utility's total gas supply cost is subtracted from its commodity rate, and the resulting distribution margin is used as the transportation rate. Gross margin is similar except that only the pipeline's gas commodity cost is subtracted from the commodity rate. For example, consider a utility with a commodity charge of $5.00 per Mcf that pays its suppliers $3.50 per Mcf for its gas supply. Of this $3.50 per Mcf, $2.50 is the pipeline's gas cost and $1.00 represents demand charges of the pipeline. In this example, the net margin would be $1.50 ($5.00 commodity charge - $3.50 total gas cost), while the gross margin would be $2.50 ($5.00 commodity charge - $2.50 pipeline gas cost).

Net and gross margin are based on the concept that sales and transportation are essentially the same except for the gas acquisition function. Consequently, both types of customers will pay the same costs from the point where the utility takes delivery of the gas to the point where it is delivered to the customer. The difference between gross and net margin is in the treatment of pipeline demand charges. These are fixed charges associated with making the facilities available to deliver gas to the utility. The argument for using net margin is that transportation customers pay the pipeline directly for transporting the customer's gas to the utility's territory, and demand charges are simply part of the utility's gas bill which should be paid by sales customers. Gross margin advocates counter that transportation customers had formerly been sales customers and the demand charge is intended to pay for making available the facilities to serve all customers. There is unfortunately no universally correct answer to this question as the facts and circumstances vary from case to case. Many utilities have contract demands far in excess of those needed by their sales customers. Gradually this problem will diminish through the expiration of contracts and by contract reductions associated with pipeline open access settlements.

The concept of basing transportation rates on the allocated cost of service is in principle no different from using that approach to set sales rates. Consequently the principles espoused in Chapter II can be applied equally well to transportation. However, one should be cautious about designing transportation rates on a different cost allocation basis than is used for sales. Sales and transportation are inextricably interlinked on the utility's system. The customers are the same; the physical facilities are the same; the utility employees dealing with the customers are the same. To attempt to create different cost of service studies for two such coadunate services would only magnify the inherently subjective element in the allocation of common costs. If transportation and sales rates are designed on dfferent bases, then customers will be inclined to use whichever service is undervalued, which could result in a revenue shortfall to be made up by other uninvolved customers (i.e. cross subsidization).

The fourth approach used to set transportation rates has been value of service. In many cases, transportation customers have alternate fuel capability and have voluntarily chosen to leave sales for transportation. Under these circumstances, it is reasonable to expect that competitive market forces will maintain competing prices at reasonable levels without the need for traditional regulatory controls. Under this approach, sales rates to core markets continue to be regulated because the utility maintains its monopoly power over these customers, while transportation rates are essentially deregulated (within rather broad limits set by the Commission), because it is believed that market forces are adequate to maintain prices at reasonable levels.

Finally, it should be noted that the distinction between firm and interruptible transportation service is not the same as for sales customers. The risk of interruption for a sales customer is due to three factors: (1) insufficient gas supply (2) insufficient pipeline capacity, and (3) insufficient utility distribution capacity. A transportation customer directly assumes the risk of insufficient gas supply and pipeline capacity. This would suggest that the rate differential between firm and interruptible transportation customers may be different than for sales customers. Additionally, if the utility's distribution system is adequate to serve its peak load, there might not be any reason to maintain the firm/interruptible distinction for transportation customers.

2. Storage/Load Balancing

The availability of load balancing and storage is another potential area in which a difference could exist between transportation and sales. If the utility has storage capability, then its purchases will not normally equal its sales in any give month. The utility will generally balance its load by purchasing additional supplies in the summer months and storing these for use in the winter. Sales customers automatically pay for this storage through their rates, and any transportation rates taken directly from such sales rates would automatically include a charge for storage. However, transportation customers can structure their purchases so as to match deliveries of the customer's gas to the utility assuming that adequate capacity is available. In this event, the transportation customer would not be using the storage and load balancing services of the utility.

This difference in service characteristics can be dealt with in two ways. The most common method is to allow the customer to carry a certain amount of excess deliveries in a "bank" which can be used up over time. The second approach is to unbundle storage costs. Under this method, the transportation charge would be reduced by the average storage cost on the utility's system. A corresponding storage charge would then be made based on the cumulative amount of excess deliveries made on the customer's behalf. Under this approach, a transportation customer could avoid paying storage costs by matching takes with deliveries, while a customer who did not do a good job of matching would pay for the storage used.

3. Supply Commitment Fees/Backup Charges

The prior section dealt with the situation where a transportation customer had more gas delivered than the customer was taking. Of greater concern is the opposite situation where the transportation customer needs more gas than is delivered by its supplier. The utility may still have an obligation to serve depending on the jurisdiction, and if so, there is normally little concern if the utility has an excess supply to sell the customer. Many transportation arrangements provide that if deliveries into the utility's system are less than the customer uses, any excess takes will automatically be billed at the utility's sales rate.

The difficulty arises when the customer relies upon the utility to provide backup supplies in the event of a shortage from its supplier or intervening pipeline capacity constraints. For the utility to stand ready to provide backup sales service, it must make a substantial long-term commitment for gas supplies, which involves the incurrence of fixed costs for these supplies. A common approach is to require that transportation customers who wish to retain the right to return to sales service pay a supply commitment fee (or back up charge) to do so. The actual calculation of this charge will depend upon the specific details of a utility's supply arrangements, but a good general rule is that the commitment fee for a transportation customer should equal the cost being paid by a sales customer to maintain the utility's supply contracts. The costs would include such items as gas supply demand charges, fixed cost minimum bills and gas inventory charges.

While most people are likely to agree with the concept that a backup charge is appropriate where the customer wishes to return to sales, there is likely to be considerable disagreement over exactly who is to pay the charge. Basically there are three approaches: (1) Make it optional, (2) Require all customers to pay, and (3) Require some customers to pay.

At first blush giving the customer the option to pay a backup charge to return to the system seems to be the most reasonable approach. The customer would thus make a choice based on the amount of risk which the customer wishes to bear. Customers who wish to have a secure source of supply would chose to pay the backup charge, while those who did not have as much to lose due to shortage would not pay the charge. Each customer would evaluate the potential adverse consequences and probability of its gas supplies not being available compared with the additional costs of the backup charge, and would chose the most economically beneficial. Utilities would obtain gas supply commitments only for sales and backup services for transportation customers, and would thus not incur any unneeded gas inventory costs.

In theory, this approach should be the best. Each customer would make a rational decision as to which option is most beneficial and the overall benefits to all customers would be maximized. However, this system has not been tested in practice and there is concern that it may not always work satisfactorily. For example, if a hospital or major industrial employer indicates that it will have to shut down due to a lack of gas supplies, it is likely that there will be a great deal of pressure to serve that customer irrespective of whether the customer paid a backup charge or not. If this happens, or is expected to happen, then the whole system may break down. Utilities may have to plan for gas supplies not only to serve sales customers and backup for transportation customers, but also for transportation customers who do not pay the backup charge. These additional supply commitments may result in additional costs which would be borne by sales and backup transportation customers, and which may thus cause additional customers to opt not to pay for backup. If this scenario occurs transportation customers who have options could be getting a free ride paid for by captive sales customers who lack options. But, there may be ways to address this concern.

One way would be to require all transportation customers to pay for backup supplies. This approach eliminates the "free lunch" problem but has little else to recommend it. Many customers would argue, quite legitimately, that they have alternative fuels available, do not need backup supplies, and that it would be economically wasteful to require them to pay for a service they do not need.

Another way would be to require customers who would be expected to need backup service to pay for it. The method for deciding which customers must take backup service should be based on some rational criterion, such as whether the customer has alternate fuel capability installed. This approach should help to reduce but probably not eliminate the "free lunch" problem.

But, it has the problem of choosing an appropriate criterion and it can appear unfair that certain customers are required to take backup service while others are not. It may also encourage the customer to seek bypass.

There is probably no universally correct answer to this concern. Each option has certain disadvantages and none appear totally satisfactory. The rate designer should work in cooperation with the gas supply planners to ensure that the approach chosen reasonably meets the needs of the utility and all customers.

4. Capacity Reservation Charges

Most pipelines carrying gas from the producing to the consuming regions were primarily built to provide service to the local distribution utilities and their customers. For the most part, the utilities have been and still are paying the fixed costs associated with these pipelines. Accordingly these customers have the right to claim capacity entitlements on these lines. If transportation customers wish to contract for firm capacity previously used by the utility (rather than contract for unused firm capacity or for interruptible capacity), then it is reasonable to expect such customers to make appropriate compensation for the use of that capacity. When and how this may best be done is an active topic at both the state and federal level. The rate designer should be aware that the entitlement to capacity on an interstate pipeline could be a valuable asset for some utilities.

What goods and services does the CPI cover?

The CPI represents all goods and services purchased for consumption by the reference population (U or W) BLS has classified all expenditure items into more than 200 categories, arranged into eight major groups. Major groups and examples of categories in each are as follows:

- FOOD AND BEVERAGES (breakfast cereal, milk, coffee, chicken, wine, full service meals, snacks)
- HOUSING (rent of primary residence, owners' equivalent rent, fuel oil, bedroom furniture)
- APPAREL (men's shirts and sweaters, women's dresses, jewelry)
- TRANSPORTATION (new vehicles, airline fares, gasoline, motor vehicle insurance)
- MEDICAL CARE (prescription drugs and medical supplies, physicians' services, eyeglasses and eye care, hospital services)
- RECREATION (televisions, toys, pets and pet products, sports equipment, admissions);
- EDUCATION AND COMMUNICATION (college tuition, postage, telephone services, computer software and accessories);
- OTHER GOODS AND SERVICES (tobacco and smoking products, haircuts and other personal services, funeral expenses).

Source: http://www.bls.gov/cpi/cpifaq.htm

AG – EXHIBIT 10

REQUEST:

Reference page 8 (lines 4-9) of Mr. Densman's testimony where he explains that the O&M budget is prepared by type of cost element, such as labor, benefits, transportation, rents, office supplies, etc. And prior year's actual costs, year-to-date actual cost and budgeted cost for the remainder of the fiscal year are used as guidelines for budgeting by functional managers and officers. At page 13 (lines 3-7), he explains the basis for the forecasted test period (ending November 30, 2014) is the FY2013 budget which includes the last ten months of FY2014 (December 2013 to September 2014) and the first two months of FY2015 (October and November 2014). At page 13 (lines 20-22), he explains the basis for the base period costs through July 31, 2013 is composed of seven months of actual results through February 2013 and five months of FY2013 budget. At page 13 (lines 13-17), he explains the expenses by rate division 009, 091, and 002/012).

a. Per Mr. Densman's testimony, he states the basis for the forecasted test year is the "FY2013 budget", but explain why a FY2013 budget would include 12 months of costs through November 2014, it would seem that this period would represent a "FY2014 budget" since it is mostly related to 2014 costs (and ends in the fiscal period 2014) and not 2013 costs.

b. Provide the actual historical costs (and identify the related period of these costs) by cost element (labor, benefits, etc.) that were used to establish the base period costs in the rate case and reconcile these historical costs to amounts in the related financial statements. Then, provide a reconciliation from the related historical costs to the base period costs by showing and explaining all adjustments and related inputs and assumptions. Provide supporting documentation and calculations.

c. Provide the actual historical costs (and identify the related period of these costs) by cost element (labor, benefits, etc.) that were used to establish the fully forecasted test period costs in the rate case and reconcile these historical costs to amounts in the related financial statements. Then, provide a reconciliation from the related historical costs to the fully forecasted test period costs by showing and explaining all adjustments and related inputs and assumptions. Provide supporting documentation and calculations.

d. Regarding the previous questions, explain and show where the historical costs are included in the budgeting model (identify module, field, and tabs) used to determine costs for the base period and the fully forecasted test period in this rate case.

AG – EXHIBIT 11

e. Regarding the previous questions, identify all historical and forecasted cost elements by expenses rate division 009 (Kentucky), 091 (Division General Office), and 002/012 (allocated expenses from SSU).

RESPONSE:

a) The FY 2013 budget does not include 12 months of costs through November 2014. The FY 2013 budget is the basis for the forecasted test period because it was the last approved budget available at the time the period was developed.

b) Please see the Company's response to Staff DR No. 1-59, Attachment 15 - FY13 OM Forecast. Please see Attachment 1 for an electronic working copy of the model.

c) Please see the response to subpart (b).

d) Please see the response to subpart (b).

e) Please see the response to subpart (b).

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, OAG_1-111_Att1 - O&M Comparison.xlsx, 24 Pages.

Respondent: Josh Densman

Atmos Energy Corporation - Kentucky
Development of Inflation Factor

Description: CPI: Urban Consumer - All Items, (Index 1982-84=100, SA)

Year	2007	2008	2009	2010	2011	2012	2013
Jan	187.587	196.708	195.843	203.490	207.551	213.649	217.217
Feb	188.122	197.596	196.421	203.274	208.156	214.524	
Mar	190.365	199.472	197.267	204.204	209.713	215.784	
Apr	191.685	200.841	197.644	204.326	211.314	216.658	
May	193.467	202.720	198.911	204.026	212.210	215.254	
Jun	194.442	205.122	201.157	203.749	211.717	215.625	
Jul	194.815	206.435	200.908	203.992	212.261	216.045	
Aug	194.716	206.251	201.823	204.985	213.009	217.300	
Sep	195.483	205.522	201.918	205.100	213.606	217.986	
Oct	195.054	202.086	202.499	205.565	212.476	217.467	
Nov	196.569	197.883	203.047	206.014	212.907	216.253	
Dec	195.819	195.383	202.738	206.136	212.505	215.962	
HALF1	190.945	200.410	197.874	203.845	210.110	215.249	
HALF2	195.409	202.260	202.156	205.299	212.794	216.836	
Annual	193.177	201.335	200.015	204.572	211.452	216.042	
Inflation%		4.22%	-0.66%	2.28%	3.36%	2.45%	

year	Annual Rate
2010	2.28%
2011	3.36%
2012	2.45%

Average Annual Inflation Rate 2.70%

Source: Table 10, Midwest Urban, Size D http://www.bls.gov/cpi/cpi_dr.htm#2011

REQUEST:

Regarding Atmos' response to Staff 1-47 regarding income taxes, address the following:

a. Explain if Atmos had a net loss on its corporate federal income tax return for 2010, 2011, 2012, 2013 or other years and explain and show how the related net operating loss carryback and carryforward has been treated in this rate case. Provide the impact on all accounts included in the forecasted test period and this rate case, including deferred federal and state income tax expense, accumulated deferred income tax reserve (liability), accumulated deferred income tax benefit (debit amounts based on a net operating loss carryforward), and all other accounts.

b. Identify the amount that the accumulated deferred state and federal income tax reserve has been reduced or offset by a deferred "debit" balance (or asset amount) related to state and federal deferred income taxes calculated on the "net operating loss carryforward." Or explain if the accumulated deferred income tax related to an operating loss carryforward (a debit deferred tax balance, or income tax benefit balance) has been recorded in a separate account and has not been netted with the accumulated deferred income tax reserve liability account. Provide all supporting documentation and calculations, and show amounts by specific account number for the base period and the fully forecasted test period.

c. Explain and identify the precedent for including a deferred tax benefit in rate base and as a reduction to the accumulated deferred income tax reserve liability account.

RESPONSE:

a) Atmos Energy has generated taxable losses on all tax returns filed for tax years ended 9/30/08 through 9/30/12. The net operating loss generated in fiscal year ended 9/30/08 was carried back to offset taxable income generated in fiscal year ended 9/30/07. The net operating loss generated in fiscal year ended 9/30/09 was carried back to offset all remaining taxable income in fiscal years ended 9/30/04 through 9/30/07 and the remainder was carried forward. Taxable losses generated in fiscal year ends 9/30/10 through 9/30/12 have also been carried forward.

   The Company's fiscal year end 9/30/12 US Form 1120 was filed in June of 2013. The NOL carryforward ADIT balance used in the forecasted test period for this rate case was as of 3/31/2013. Therefore, the net operating loss carryforwards from fiscal year end 9/30/09 through 9/30/11 tax returns, as well as the estimated fiscal year end 9/30/12 impact to the NOL recorded in September of 2012 and

AG – EXHIBIT 12

the estimated FY 2013 impact to the NOL recorded in March 2013 comprise the utility deferred asset ADIT amount of $340,724,523 [before allocation] included in this rate case.

The federal NOL carryover deferred tax asset is recorded to accounts 1900 and 2820 and does not impact other ADIT accounts included in the forecasted test period and rate case.

b) The federal net operating loss carryover deferred tax asset is recorded in account 1900 and 2820 and separately stated on the Company's ADIT schedule, provided as Attachment 1 to the Company's response to OAG DR No. 1-47. The forecast was provided in the workpaper "ADIT for KY.xlsx" attached to the Company's response to Staff DR No. 1-59. This deferred tax asset is not netted with any ADIT liability account.

The state net operating loss carryover recorded in division 091 and included in Attachment 1 to the Company's response to OAG DR No. 1-47 is also recorded to account 1900 and 2820 and is not netted with any ADIT liability account.

c) The NOL is properly accounted for per GAAP in account 1900 and 2820 and is a component of ADIT. The Company has made rate filings and received recovery in rates consistent with this accounting treatment in each of its jurisdictions since it first experienced an NOL on its tax returns. The Company is unaware of specific precedent in Kentucky where the issue was litigated as part of rate case; however the issue was fully litigated most recently in the Company's Texas Case GUD No. 10170 where the treatment, as presented in this case, was adopted in the final order.

Respondent: Greg Waller

REQUEST:

Reference the testimony of Mr. Napier at pages 13 and 14 regarding Wireless Meter Reading project. If the following is not answered to the above question, please explain the following:

a. Whether the device only sends a signal to the company;

b. Type by make, model and year;

c. Type and manner of signal used for communicating with the company;

d. Type and manner of signal used for communicating with the customer, if applicable;

e. Life cycle of the device;

f. The cost for each meter, broken down by cost per unit and installation.

RESPONSE:

a) The device only communicates with the Company.

b) Sensus FlexNet Gas Transmitters (NA2W generation - 2012)

100GM for Sensus/Rockwell Meters
200GM for Sprague Meters
300GM for American Meters
400GM for National/Lancaster Meters
500GM for Large Commercial Sensus/Rockwell Meters
600GM for Large Commercial American Meters
700GM for Large volume meters - pulse output model

Network Base Stations
Remote Base Station (FRP)
Metro Base Station
S50 Base Station (indoor or outdoor)

Head End System
FlexNet - Regional Network Interface (RNI) Current version 2.01. Upgrading in FY14 to version 3.1

c) Please see the Company's response to Staff DR No. 2-59.

AG – EXHIBIT 13

d) Please see the Company's response to OAG DR No. 1-47 subpart (a)

e) The FlexNet device is battery operated and has a manufacturer warranty of 20 years. During the first 10 years, the device replacement is at 100%. Then beginning in year 11 through year 20, Atmos Energy will pay a gradually increasing percentage of the replacement value, i.e., year 11 - 40%. This increases 5% per year until the end of the 20 year warranty period.

The service life of the device is projected to be at least 20 years but likely longer.

f) The device installed is not a meter. Measurement of gas usage continues to be performed by decades' proven gas metering technology. The WMR device simply collects and counts the revolutions of the meter electronically, and duplicates the readings that are captured mechanically by the meter index.

Approximate Cost:

	Residential Models	Large Commercial Models
Cost of the device is:	$60.24	$102.74
Average installation cost:	$ 5.78	$ 5.78
Overheads	$24.44	$ 24.44
Total cost per installation:	$90.46	$132.96

Respondent: Earnest Napier

RESPONSE:

a)

1) Please see Attachment 1.

2) Please see Attachment 1.

3) Please see Attachment 1.

4) Below is the amount of income credits resulting from prior deferrals of federal income taxes:

UCG Regulatory Assets	
Amount realized	$3,319,295
Amount amortized as of 09/30/2012	$1,920,072
UCG Regulatory Liabilities	
Amount realized	$4,757,340
Amount amortized as of 09/30/2012	$3,463,236

5) a) Investment credit realized is $3,304,551.

b) Investment credit amortized - Pre-Revenue Act of 1971: Not applicable.

c) Investment credit amortized - Revenue Act of 1971: As of 09/30/2012 amount equals $3,266,892.

6) Not applicable.

7) The Company does not file tax returns or calculate federal taxable income at a "Kentucky only" level. Taxes are filed and current taxable income is calculated on a utility combined basis only. Kentucky State income taxes are apportioned based upon state tax law. As such, the Company has not made calculations utilizing such apportionments which may overstate or understate taxes paid to Kentucky based upon income earned by the Company in other states. The Company's filing at MFR 16 (13) (e) calculates income tax expense for ratemaking purposes. Deferred income taxes are also reduced from Ratebase and shown at MFR 16 (13) (b). Income tax expense recorded on the general ledger for the Kentucky operations is attributed based on the Kentucky only pre-tax book income which includes allocations of shared costs from Shared Services and allocations of permanent differences to Kentucky. This amount is not

AG – EXHIBIT 14

appropriate for ratemaking purposes. Deferred income taxes are determined based upon activity on a divisional basis.

8) Please see the response to subpart (7).

9) Please see Attachment 2 for Atmos Energy's 2010 Federal tax return and Atmos Energy's 2010 Kentucky State tax return. The tax returns provided in Attachment 2 are considered confidential.

10) Please see Attachment 3.

b) Please see Attachment 4.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-47_Att1 - Federal Operating Income Taxes.pdf, 4 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, Staff_1-47_Att2 - Tax Returns - REDACTED.pdf, 2 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, Staff_1-47_Att3 - Franchise Fee Payments by City.pdf, 1 Page.

ATTACHMENT 4 - Atmos Energy Corporation, Staff_1-47_Att4 - Other Operating Taxes.pdf, 4 Pages.

Respondent: Greg Waller

KY DR Q47 (a) 1 & 2

Atmos Energy Corporation
Deferred Tax Balances - Shared Services (Company 010)
CYE 12/31/2012

(ALL NUMBERS ARE TAX EFFECTED)

DEFERRED TAX ASSETS / (LIABILITIES)		CTC	GL ACCT	Type	Fiscal 2011 9/30/2011 Ending Balance	Fiscal 2012 12/31/2011 Ending Balance	Fiscal 2012 3/31/2012 Ending Balance	Fiscal 2012 6/30/2012 Ending Balance	Fiscal 2012 9/30/2012 Ending Balance	Fiscal 2013 12/31/2012 Ending Balance
Directors Deferred Bonus	002DIV	ACC01	1900	A	211,066	211,066	211,066	211,066	186,744	186,744
MIP / VPP Accrual	002DIV	ACC04	1900	A	1,926,378	1,926,378	1,926,378	1,926,378	1,887,068	1,887,068
MIP / VPP Accrual	012DIV	ACC04	1900	A	(1,365,351)	(1,365,351)	(1,365,351)	(1,365,351)	(171,475)	(171,475)
Miscellaneous Accrual	002DIV	ACC05	1900	A	14,214	14,214	14,214	14,214		-
Miscellaneous Accrued	002DIV	ACC05	2830	L					14,445	14,445
Self Insurance - Adjustment	002DIV	ACC08	1900	A	1,568,123	1,568,123	1,568,123	1,568,123	2,276,932	2,276,932
Vacation Accrual	002DIV	ACC11	1900	A	6,232	6,232	6,232	6,232	-	-
Vacation Accrual	002DIV	ACC11	2830	L					95,162	95,162
Vacation Accrual	012DIV	ACC11	1900	A	5,572	5,572	5,572	5,572		-
Vacation Accrual	012DIV	ACC11	2830	L					(89,728)	(89,728)
Worker's Comp Insurance Reserve	002DIV	ACC12	1900	A	50,721	50,721	50,721	50,721	17,875	17,875
Worker's Comp Insurance Reserve	012DIV	ACC12	1900	A	(32,216)	(32,216)	(32,216)	(32,216)	-	-
Deferred Expense Projects	002DIV	DTE09	2830	L	61,381	61,381	61,381	61,381	(356)	(356)
Deferred Expense Projects	002DIV	DTE09	2820	P		(90)	(388)	(388)		(1,345)
Deferred Gas Costs	002DIV	DEA01	2830	L					(592,309)	(592,309)
Rabbi Trust - True Up	002DIV	NBP02	1900	A	4,279	4,279	4,279	4,279	-	-
SERP Adjustment	002DIV	NBP03	1900	A	25,510,036	25,510,036	25,510,036	25,510,036	26,397,972	26,397,972
FAS 106 Adjustment	002DIV	PRB03	2820	P		207,232	519,188	834,373		(265,991)
Restricted Stock Grant Plan	002DIV	NBP05	1900	A	5,319,945	5,319,945	5,319,945	5,319,945	7,061,014	7,061,014
Rabbi Trust	002DIV	NBP06	1900	A	1,999,696	1,999,696	1,999,696	1,999,696	1,650,300	1,650,300
Restricted Stock - MIP	002DIV	NBP13	1900	A	4,371,139	4,371,139	4,371,139	4,371,139	5,675,325	5,675,325
Director's Stock Awards	002DIV	NBP16	1900	A	2,956,402	2,956,402	2,956,402	2,956,402	2,843,211	2,843,211
Director's Stock - Temp	002DIV	NBP18	2830	L	(678,829)	(678,829)	(678,829)	(678,829)	-	-
Allowance for Doubtful Accounts	002DIV	ONI01	1900	A	2	2	2	2	625,810	625,810
Clearing Account - Adjustment	002DIV	ONI03	1900	A	18,873	18,873	18,873	18,873	51,621	51,621
Clearing Account - Adjustment	012DIV	ONI03	1900	A	268	268	268	268	264	264
Charitable Contribution Carryover	002DIV	ONI04	1900	A	217,029	217,029	217,029	217,029	3,901,046	3,901,046
Charitable Contribution Carryover	012DIV	ONI04	1900	A	15,210	15,210	15,210	15,210	16,375	16,375
Prepayments	002DIV	ONI31	2830	L	(981,254)	(981,254)	(981,254)	(981,254)	(435,332)	(435,332)
Prepayments	012DIV	ONI31	2830	L	(944,023)	(944,023)	(944,023)	(944,023)	(1,376,000)	(1,376,000)
Stock Option Expense	002DIV	ONI33	1900	A	332,080	332,080	332,080	332,080	327,592	327,592
Federal & State Tax Interest	002DIV	ONI61	2830	L	(411,878)	(411,878)	(411,878)	(411,878)	(87,252)	(87,252)
Intra Period Tax Allocation	002DIV	OTH	1900	A	(6)	(6)	(6)	(6)	-	-
Pension Expense	002DIV	PEN01	2830	L	(14,371,402)	(14,371,402)	(14,371,402)	(14,371,402)	(32,124,191)	(32,124,191)
Pension Expense	002DIV	PEN01	2820	P		(234,775)	389,848	(7,338,730)		(238,318)
FAS 106 Adjustment	002DIV	PRB01	1900	A	5,277,353	5,277,353	5,277,353	5,277,353	7,012,097	7,012,097
FAS 106 Adjustment	002DIV	PRB01	2820	P		1,248,393	1,594,346	1,752,013		77,747
FAS 106 Adjustment	012DIV	PRB02	1900	A	-	-	-	-	(834)	(834)
Regulatory Liability - Atmos 109	002DIV	RGL01	1900	A	9,790	9,790	9,790	9,790	5,022	5,022
					31,690,331	32,311,091	33,583,125	26,327,599	24,168,369	23,760,462
Fixed Asset Cost Adjustment	002DIV	TXA01	2820	P	(28,476,091)	(24,924,614)	(26,580,344)	(28,187,941)	(25,410,019)	(28,871,903)
Fixed Asset Cost Adjustment	012DIV	TXA01	2820	P	(40,064,057)	(40,064,057)	(40,064,057)	(40,064,057)	(37,822,078)	(37,322,078)
Depreciation Adjustment	002DIV	TXA02	2820	P	3,959,844	3,959,844	3,959,844	3,959,844	1,616,329	875,977
Depreciation Adjustment	012DIV	TXA02	2820	P	30,038,691	30,038,691	30,088,691	30,088,691	26,306,713	26,306,713
Section 481(a) Cushion Gas	002DIV	TXA13	2820	P	556,839	556,809	556,809	556,809	549,294	549,294
Section 481(a) Line Pack Gas	002DIV	TXA14	2820	P	67,557	67,557	67,557	67,557	66,648	66,648
IRS Audit Assessment - Cost	002DIV	TXA15	2820	P	1,874,769	1,874,769	1,874,769	1,874,769	-	-
IRS Audit Assessment - Accum	002DIV	TXA16	2820	P	(516,058)	(516,058)	(516,058)	(516,058)		-
CWIP	002DIV	TXA26	2820	P	204,465	204,465	204,465	204,465	(354,579)	(354,579)
CWIP	012DIV	TXA26	2820	P	(3,583,122)	(3,583,122)	(3,583,122)	(3,583,122)	(15,264,555)	(15,764,553)
SUBTOTAL PLANT RELATED DEFERRED					(30,838,053)	(32,380,616)	(34,012,049)	(35,644,013)	(49,813,877)	(54,510,544)
OTHER TAX EFFECTED ITEMS										
FD - NOL Credit Carryforward - Utility	002DIV	TAX02U	1900	A	262,396,156	262,396,156	262,396,156	262,396,156	336,718,783	336,718,783
FD - NOL Credit Carryforward - Non Reg	002DIV	TAX02NR	1900	A	(194,703,517)	(194,703,517)	(194,703,517)	(194,703,517)	(183,429,559)	(193,429,559)
FD - NOL Credit Carryforward - Utility	002DIV	TAX02U	2820	P		14,949,655	(33,611,183)	3,037,009		20,245,002
FD - NOL Credit Carryforward - Non Reg	002DIV	TAX02NR	2820	P		(2,616,532)	1,475,888	(6,018,047)		(5,339,025)
ST - State Net Operating Loss	002DIV	TAX04	1900	A	-	-	-	-	1	1
FD - FAS 115 Adjustment	002DIV	TAX06	2830	L	(1,519,093)	(2,022,938)	(1,161,535)	(2,600,014)	(3,334,311)	(3,110,269)
FD - Federal Tax on State NOL	002DIV	TAX12	1900	A					2	2
FD - FAS 158 Measure Date Change	002DIV	TAX22	1900	A	4,573,142	4,573,142	4,573,142	4,573,142	(61,451)	(61,451)
FD - AMT Minimum Tax Credit	002DIV	TAX23	1900	A	10,099,286	10,099,286	10,099,286	10,099,286	10,099,282	10,099,286
ST - Enterprise Zone ITC	002DIV	TAX37	1900	A	-	-	-	434,812	484,812	484,813
FD - Treasury Lock Adjustment realized	002DIV	TAX40	2830	L	(4,934,091)	(5,110,488)	(5,196,320)	(5,482,112)	(5,591,332)	(5,774,625)
FD - Treasury Lock Adjustment unrealized	002DIV	TAX41	2830	L	24,094,992	25,809,166	16,992,749	33,532,544	31,319,561	34,173,674
SUBTOTAL OTHER TAX EFFECTED ITEMS					100,308,640	113,375,923	73,694,678	108,125,059	175,805,794	184,156,386
TOTAL DEFERRED TAX ASSETS / (LIABILITIES)					101,160,918	113,301,398	73,235,956	98,808,615	150,241,286	153,406,303
Deferred Tax Assets - Others			1900		130,781,903	130,781,903	130,781,853	131,268,716	213,526,784	213,525,784
Deferred Tax Liabilities - Plant Related			2820		(30,838,053)	(18,870,233)	(48,684,347)	(42,527,013)	(49,812,877)	(39,812,675)
Deferred Tax Liabilities - Others			2830		1,217,068	1,389,728	(8,861,630)	10,068,912	(13,471,621)	(20,306,806)
Total										
A1900 28201				A	126,370,845	126,370,845	126,370,845	126,370,845	208,894,344	208,894,344
A1900 28206				A	4,411,058	4,411,058	4,411,058	4,895,870	4,631,441	4,631,441
A2820 28201				P	(28,270,993)	(10,245,029)	(46,078,855)	(39,442,725)	(46,085,656)	(36,475,635)
A2820 28206				P	(2,567,060)	(2,584,776)	(2,605,492)	(3,084,286)	(3,127,222)	(3,337,040)
A2830 28201				L	1,143,560	1,245,939	(8,153,631)	9,216,556	(12,571,741)	(18,974,292)
A2830 28206				L	73,508	93,788	(707,999)	852,356	(899,881)	(1,332,509)
TOTAL TAX EFFECTED					101,160,918	111,301,387	73,235,957	98,808,614	150,241,286	153,406,304

KY DR Q47 (a) 1 & 2

Atmos Energy Corporation
Deferred Tax Balances - Kentucky Division - 009DIV
CYE 12/31/2012

(ALL NUMBERS ARE TAX EFFECTED)				Fiscal 2011	Fiscal 2012	Fiscal 2012	Fiscal 2012	Fiscal 2012	Fiscal 2013
				9/30/2011	12/31/2011	3/31/2012	6/30/2012	9/30/2012	12/31/2012
DEFERRED TAX ASSETS / (LIABILITIES)	CTC	GL ACCT	Type	Ending Balance	Ending Balance	Ending Balance	Ending Balance	Ending Balance	Ending Balance
MIP / VPP Accrual	ACC04	1900	A	296,049	296,049	296,049	296,049	47,254	47,254
Vacation Accrual	ACC11	2830	L	0	0	0	0	(59,917)	(59,917)
Worker's Comp Insurance Reserve	ACC12	1900	A	137,412	137,412	137,412	137,412	-	-
Customer Advances	CAP01	1900	A	962,005	962,005	962,005	962,005	1,013,354	1,013,354
DIG on Fixed Assets - WKG	DVA19	1900	A	183,916	183,916	183,916	183,916	-	-
Deferred Gas Costs	GCA01	2830	L	28,411	28,411	28,411	28,411	(61,846)	(61,846)
Over Recoveries of PGA	GCA03	2830	L	(2,126,384)	(2,126,384)	(2,126,384)	(2,126,384)	(1,157,650)	(1,157,650)
SEBP Adjustment	NBP03	1900	A	197,374	197,374	197,374	197,374	-	-
Capitalized Selling Expense	NTE03	1900	A	10,398	10,398	10,398	10,398	6,155	6,155
Allowance for Doubtful Accounts	ONT02	1900	A	47,806	47,806	47,806	47,806	75,974	75,974
Clearing Account - Adjustment	ONT03	1900	A	429	429	429	429	423	423
Charitable Contribution Carryover	ONT04	1900	A	356,611	356,611	356,611	356,611	433,674	433,674
Prepayments	ONT31	2830	L	(66,536)	(66,536)	(66,536)	(66,536)	(71,861)	(71,861)
Rate Case Accrual	ONT32	2830	L	(6,759)	(6,759)	(6,759)	(6,759)	-	-
FAS 106 Adjustment	PRB01	1900	A	983,978	983,978	983,978	983,978	(1,218,005)	(1,218,005)
				1,004,710	1,004,710	1,004,710	1,004,710	(992,245)	(992,245)
Fixed Asset Cost Adjustment	FXA01	2820	P	(47,497,529)	(47,497,529)	(47,497,529)	(47,497,529)	(47,776,114)	(47,776,114)
Depreciation Adjustment	FXA02	2820	P	(10,382,312)	(10,382,312)	(10,382,312)	(10,382,312)	(12,826,587)	(12,826,587)
CWIP	FXA26	2820	P	(221,659)	(221,659)	(221,659)	(221,659)	(470,359)	(470,359)
SUBTOTAL PLANT RELATED DEFERRED				(58,101,500)	(58,101,500)	(58,101,500)	(58,101,500)	(61,073,060)	(61,073,060)
OTHER TAX EFFECTED ITEMS									
ST - State Bonus Depreciation	TAX05	2820	P	0	0	0	0	594,432	594,432
FD - Federal Benefit on State Bonu	TAX11	2820	P	0	0	0	0	(208,051)	(208,051)
SUBTOTAL OTHER TAX EFFECTED ITEMS				0	0	0	0	386,381	386,381
TOTAL DEFERRED TAX ASSETS / (LIABILITIES)				(57,096,790)	(57,096,790)	(57,096,790)	(57,096,790)	(61,678,924)	(61,678,924)
Deferred Tax Assets - Non Plant Related		1900		3,175,978	3,175,978	3,175,978	3,175,978	359,028	359,028
Deferred Tax Liabilities - Plant Related		2820		(58,101,500)	(58,101,500)	(58,101,500)	(58,101,500)	(60,686,679)	(60,686,679)
Deferred Tax Liabilities - Non Plant Related		2830		(2,171,268)	(2,171,268)	(2,171,268)	(2,171,268)	(1,351,274)	(1,351,274)
Total									
A1900-28201			A	2,911,599	2,911,599	2,911,599	2,911,599	336,406	336,406
A1900-28206			A	264,379	264,379	264,379	264,379	22,624	22,624
A2820-28201			P	(53,264,942)	(53,264,942)	(53,264,942)	(53,264,942)	(57,432,672)	(57,432,672)
A2820-28206			P	(4,836,557)	(4,836,557)	(4,836,557)	(4,836,557)	(3,254,007)	(3,254,007)
A2830-28201			L	(1,990,525)	(1,990,525)	(1,990,525)	(1,990,525)	(1,266,125)	(1,266,125)
A2830-28206			L	(180,743)	(180,743)	(180,743)	(180,743)	(85,149)	(85,149)
Deferred Income Taxes				(57,096,790)	(57,096,790)	(57,096,790)	(57,096,790)	(61,678,925)	(61,678,925)

KY DR Q47 (a) 1 & 2

Atmos Energy Corporation
Deferred Tax Balances - Brentwood Division - 091DIV
CYE 12/31/2012

(ALL NUMBERS ARE TAX EFFECTED)

DEFERRED TAX ASSETS / (LIABILITIES)	CTC	GL ACCT	Type	Fiscal 2011 9/30/2011 Ending Balance	Fiscal 2012 12/31/2011 Ending Balance	Fiscal 2012 3/31/2012 Ending Balance	Fiscal 2012 6/30/2012 Ending Balance	Fiscal 2012 9/30/2012 Ending Balance	Fiscal 2013 12/31/2012 Ending Balance
Directors Deferred Bonus	ACC03	1900	A	5,045	5,045	5,045	5,045	-	-
MIP / VPP Accrual	ACC04	1900	A	35,376	35,376	35,376	35,376	247,263	247,263
Accrued Environmental Asset	ACC05	2830	L	(6,328)	(6,328)	(6,328)	(6,328)	-	-
Self Insurance - Adjustment	ACC08	1900	A	0	0	0	0	3,985	3,985
Vacation Accrual	ACC11	1900	A	(53,879)	(53,879)	(53,879)	(53,879)	-	-
Vacation Accrual	ACC11	2830	L					30,504	30,504
Worker's Comp Insurance Reserve	ACC12	1900	A	336,999	336,999	336,999	336,999	221,929	221,929
Customer Advances	CAP01	1900	A	(13,150)	(13,150)	(13,150)	(13,150)	-	-
Deferred Expense Projects	DTE09	2830	L	(87,175)	(87,175)	(87,175)	(87,175)	-	-
RAR 91/93 Bond Cost Amortized	DVA05	1900	A	21,414	21,414	21,414	21,414	22,561	22,561
RAR 91/93 Bond Costs Capitalized	DVA06	2830	L	(36,827)	(36,827)	(36,827)	(36,827)	(36,330)	(36,330)
DIG on Fixed Assets	DVA18	1900	A	24,671	24,671	24,671	24,671	-	-
DIG on Fixed Assets - UCG Storage	DVA18	2830	L	(1,187,833)	(1,187,833)	(1,187,833)	(1,187,833)	(1,171,781)	(1,171,781)
RAR 86/90 Lease Expense Amortiz.	DVA26	2830	L	(128,601)	(128,601)	(128,601)	(128,601)	(132,238)	(132,238)
Deferred Gas Costs	GCA01	2830	L	0	0	0	0	(676,175)	(676,175)
Deferred Gas Costs	GCA01	2820	P		(4,174,174)	(2,465,270)	5,894,904		(2,380,195)
Over Recoveries of PGA	GCA03	2830	L	0	0	0	0	-	-
Over Recoveries of PGA	GCA03	2820	P				(4,902,312)		1,180,208
Deferred ITC - UCG Non-utility	ITC02	1900	A	16,987	16,987	16,987	16,987	11,621	11,621
Deferred ITC - UCG	ITC03	1900	A	6,678	6,678	6,678	6,678	2,124	2,124
SEBP Adjustment	NBP03	1900	A	1,121,850	1,121,850	1,121,850	1,121,850	1,307,522	1,307,522
SEBP Adjustment	NBP03	2820	P		989	2,472	3,955		2,356
UNICAP Section 263A Costs	NTE11	1900	A	969,977	969,977	969,977	969,977	1,356,302	1,356,302
Allowance for Doubtful Accounts	ONT02	1900	A	128,887	128,887	128,887	128,887	188,700	188,700
Allowance for Doubtful Accounts	ONT02	2820	P		115,876	316,669	372,058		51,809
Clearing Account - Adjustment	ONT03	1900	A	972	972	972	972	(387,258)	(387,258)
Clearing Account - Adjustment	ONT03	2820	P						388,215
Charitable Contribution Carryover	ONT04	1900	A	70,096	70,096	70,096	70,096	69,162	69,162
RAR CFWE 1920-1985	ONT06	2830	L	(70,831)	(70,831)	(70,831)	(70,831)	(69,873)	(69,873)
Union Gas - Non Compete	ONT21	1900	A	413,125	413,125	413,125	413,125	407,543	407,543
Palmyra - Non Compete	ONT23	1900	A	14,330	14,330	14,330	14,330	7,067	7,067
Rate Case Accrual	ONT32	2830	L	0	0	0	0	-	-
Rate Case Accrual	ONT32	2820	P		44,394	122,982	164,186		(581)
WACOG to FIFO Adjustment	ONT52	2830	L	(147,909)	(147,909)	(147,909)	(147,909)	(317,389)	(317,389)
WACOG to FIFO Adjustment	ONT52	2820	P		102,270	(245,855)	(230,369)		(230,381)
Intra Period Tax Allocation	OTH	1900	A	37,055	37,055	37,055	37,055	-	-
Intra Period Tax Allocation	OTH	2820	P		406,982	813,964	1,381,385		775,524
FAS 106 Adjustment	PRB01	1900	A	9,531,902	9,531,902	9,531,902	9,531,902	5,752,522	5,752,522
FAS 106 Adjustment	PRB01	2820	P		(151,098)	20,162	(303,794)		(116,797)
Regulatory Liability - UCGC 109	RGL04	2830	L	(568,459)	(568,459)	(568,459)	(568,459)	(510,718)	(510,718)
Regulatory Liability - UCGC Rate	RGL05	1900	A	570,351	570,351	570,351	570,351	472,352	472,352
SUBTOTAL NON PLANT RELATED DEFERRED				11,094,723	7,340,280	9,571,846	13,386,736	6,799,394	6,469,613
Fixed Asset Cost Adjustment	FXA01	2820	P	(3,074,020)	(5,742,850)	(5,773,672)	(7,084,209)	(2,575,535)	(4,872,655)
Depreciation Adjustment	FXA02	2820	P	1,135,790	(1,009,291)	(4,131,634)	(6,866,790)	1,975,656	(1,003,050)
CWIP	FXA26	2820	P	12,541	12,541	12,541	12,541	13,668	13,668
SUBTOTAL PLANT RELATED DEFERRED				(1,925,689)	(6,739,601)	(9,892,765)	(13,938,459)	(586,212)	(5,862,038)
OTHER TAX EFFECTED ITEMS									
ST - State Net Operating Loss	TAX04	1900	A	3,142,249	3,142,249	3,142,249	3,142,249	3,806,488	3,806,488
ST - State Bonus Depreciation	TAX05	2820	P	5,784,289	5,784,289	5,784,289	5,784,289	6,418,669	6,418,669
FD - Federal Benefit on State Bonu	TAX11	2820	P	(2,024,502)	(2,024,502)	(2,024,502)	(2,024,502)	(2,246,535)	(2,246,535)
FD - Federal Tax on State NOL	TAX12	1900	A	(1,099,787)	(1,099,787)	(1,099,787)	(1,099,787)	(1,375,810)	(1,375,810)
SUBTOTAL OTHER TAX EFFECTED ITEMS				5,802,249	5,802,249	5,802,249	5,802,249	6,602,812	6,602,812
TOTAL DEFERRED TAX ASSETS / (LIABILITIES)				14,881,282	6,411,929	5,481,330	5,248,526	12,815,995	7,210,387
Deferred Tax Assets - Others		1900		15,281,148	15,281,148	15,281,148	15,281,148	12,114,073	12,114,073
Deferred Tax Liabilites - Plant Related		2820		1,834,098	(6,635,256)	(7,565,854)	(7,798,658)	3,585,922	(2,019,685)
Deferred Tax Liabilites - Others		2830		(2,233,963)	(2,233,963)	(2,233,963)	(2,233,963)	(2,884,001)	(2,884,001)
Total									
A1900-28201			A	11,039,952	11,039,952	11,039,952	11,039,952	8,337,175	8,337,175
A1900-28206			A	4,241,196	4,241,196	4,241,196	4,241,196	3,776,898	3,776,898
A2820-28201			P	(3,789,891)	(11,801,441)	(12,681,737)	(12,901,958)	(2,784,133)	(8,159,373)
A2820-28206			P	5,623,989	5,166,185	5,115,883	5,103,299	6,370,055	6,139,688
A2830-28201			L	(2,048,001)	(2,048,001)	(2,048,001)	(2,048,001)	(1,771,593)	(1,771,593)
A2830-28206			L	(185,962)	(185,962)	(185,962)	(185,962)	(1,112,407)	(1,112,407)
Deferred Income Taxes				14,881,282	6,411,929	5,481,331	5,248,526	12,815,995	7,210,387

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Atmos Energy Corporation
Federal income taxes - operating
CYE 12/31/2012

GL ACCT 4091

Company	Service	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Grand Total
10	002 DIV	431,369	503,357	(29,661,750)	393,224	470,967	6,449,750	468,614	778,093	26,553,701	(328,815)	(260,793)	10,315,512	16,113,229
10	012 DIV									21,891,178				21,891,178
10 Total		431,369	503,357	(29,661,750)	393,224	470,967	6,449,750	468,614	778,093	48,444,880	(328,815)	(260,793)	10,315,512	38,004,408
50	009 DIV									767,973				767,973
50	091 DIV	4,519,078	3,528,404	1,209,216	1,038,753	32,712	(418,208)	378,185	120,896	27,041,214	828,544	1,724,431	(1,327,101)	38,676,123
50 Total		4,519,078	3,528,404	1,209,216	1,038,753	32,712	(418,208)	378,185	120,896	27,809,186	828,544	1,724,431	(1,327,101)	39,444,096
Grand Total		4,950,447	4,031,761	(28,452,535)	1,431,977	503,679	6,031,542	846,798	898,989	76,254,066	499,729	1,463,638	8,988,411	77,448,504

Kentucky Office of Attorney General
Remove NOLC ADIT
Atmos Energy Corporation
Forecasted Test Period November 30, 2014

Exhibit BCO-2
Schedule A-10

A	B	C	D	E	F	G	H	I	J	K
							KY			
Line				Staff 1-59	Staff 1-47	AG 2-78	Mid-States	KY Juris.	Staff 1-59	Staff 1-47
1	Div.	Acct.	Descrip.	NOLC	NOLC		Alloc.	Alloc.	Allocated	Allocated
2				12/31/2012	12/31/2012				12/31/2012	12/31/2012
3	0.002	1900	Fed. NOL Credit Carryforward - Utility	355,963,785			11.10%	50%	19,755,990	-
4	.010.	1900	Fed. NOL Credit Carryforward - Utility		336,718,783		11.10%	50%	-	18,687,892
5	.010.	1900	Fed. NOL Credit Carryforward - Utility						-	-
6	0.012	1900		-	Div. not provided		10.78%	53.04%	-	
7	0.009	1900		-	Div. not provided		100%	100%	-	
8	0.091	1900	State NOL	3,806,488	3,806,488		100%	50%	1,903,244	1,903,244
9	0.091	1900	Fed. Tax on State NOL	(1,875,810)	(1,875,810)		100%	50%	(937,905)	(937,905)
10				357,894,463	338,649,461	340,724,523			20,721,329	19,653,231
11										
12				Estimate of Atmos average increase through March 2013					1,500,000	1,500,000
13				**OAG Adjustment - Total Net Operating Loss Carryforward**					**22,221,329**	21,153,231
14										
15				Deferred Income Tax and Investment Tax Credit per Sch. B-1 F, page 1					45,893,236	
16				**Total Adjusted Deferred Income Tax and Investment Tax Credit**					**68,114,565**	

AG – EXHIBIT 15

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 11th day of February, 2013.

CASE NO. 11-1627-G-42T (REOPENED)

MOUNTAINEER GAS COMPANY, a public utility, Charleston, Kanawha County.

Rule 42T application to increase gas rates and charges.

COMMISSION ORDER

The Commission denies a petition to reconsider filed by Mountaineer Gas Company.

BACKGROUND & DISCUSSION

The Commission issued its comprehensive order in this base rate proceeding on October 31, 2012. Comm'n Order at 1-58, as corrected Nov. 5, 2012 (November 2012 Order).

On November 21, 2012, Mountaineer Gas Company (Mountaineer or Company) filed a Limited Petition For Reconsideration, pursuant to Rule 19.3 of the Commission Rules of Practice and Procedure, 150 C.S.R. Series 1. Limited Petition for Reconsideration at 1-24. Mountaineer asserted that the Commission should have adopted a proposed $2.6 million offset, which Mountaineer refers to as the Minimum Adjustment, to accumulated deferred income taxes (ADITs) associated with the thirteen-month average of net operating loss carry-forwards and alternative minimum tax credit carry-forwards (NOLs). Mountaineer argues that the Minimum Adjustment was the minimum offset to the Company's ADIT balance required (i) to account for NOLs generated exclusively by the impact of accelerated depreciation deductions and (ii) to avoid a normalization violation.

Mountaineer argues the only justification for rejecting the Minimum Adjustment to ADITs addressed in the November 2012 Order is the Commission Staff's reference to the January 17, 2012 decision in Bluefield Gas Company, Case Number 11-0410-G-42T, in which the Commission found no potential normalization violation because the utility had not proven that its NOL carry-forwards were entirely traceable to accelerated depreciation. Mountaineer also claims that the November 2012 Order did not discuss

AG – EXHIBIT 16

evidence presented by the Company and the Commission Consumer Advocate Division (CAD) of the (i) significant risk arising from a failure to incorporate the Minimum Adjustment in rates, (ii) general consensus that a deferred tax asset must be recognized for NOL carry-forwards arising from a utility's claim of accelerated depreciation, and (iii) decisions from other regulators that uniformly approve this approach. By contrast, Mountaineer claims it is undisputed that the NOLs involved in its requested Minimum Adjustment were entirely traceable to accelerated depreciation. Limited Petition for Reconsideration at 2-3.

Mountaineer argues that (i) by flowing through to current customers the benefit of accelerated depreciation associated with the NOLs, the level of ADIT's recognized in the November 2012 Order creates a significant risk of violating normalization rules and (ii) under United States Treasury regulations, Mountaineer will have to report a "change in regulatory accounting." Mountaineer noted that the Commission has repeatedly recognized the benefits of accelerated depreciation deductions. A tax normalization violation, though, would prevent Mountaineer from claiming accelerated tax depreciation on its federal income tax returns for assets existing as of the violation date and for future years. The IRS could require the Company to amend its tax returns for open tax years, which in turn could expose Mountaineer to IRS penalties and interest. The utility and its customers also would lose the "interest-free loan" associated with the deferral of federal income tax payments. As a consequence, the Company would essentially have to repay the federal ADIT liability of $15.7 million on its books -- resulting in a significant increase to rate base that would be reflected in higher customer rates. Id. at 3-4.

If the Commission does not change its position, Mountaineer asked the Commission to direct Mountaineer to request a private letter ruling from the IRS on whether the November 2012 Order complies with the normalization requirements for using accelerated depreciation methods for federal income tax purposes. If the IRS upholds the Commission's ruling, then no further action need occur. If the IRS finds that the Commission's rejection of the Minimum Adjustment creates a normalization violation, then Mountaineer proposed that the Commission correct its "error", and if required to avoid a normalization violation, authorize Mountaineer to recover the additional revenue associated with including the Minimum Adjustment in rate base, retrospectively from the effective date of the Order and prospectively as well. Id. at 4.

On November 26, 2012, the CAD filed a letter advising that its position on the ADIT issue was adequately explained in its initial and reply briefs and in the testimony of CAD witness Ralph C. Smith. Ltr. at 1.

On November 30, 2012, Staff filed a letter stating that Staff disagrees with the position in Mountaineer's Limited Petition for Reconsideration. Staff recommended that the Commission affirm the position on ADITs that was stated in the October 31, 2012 Order, and that is consistent with the position of Staff taken in its filings and in the testimony of Staff witnesses at the hearing held on July 17- 19, 2012. Ltr. at 1.

DISCUSSION

The Commission denies the Limited Petition for Reconsideration and will address the arguments raised therein.

A. No Legal or Evidentiary Basis

Contrary to Mountaineer's claim that the Commission only relied on Conclusion of Law 11, the Commission also relied on Conclusion of Law 12 and listed two Findings of Fact, FOF 6 and 7 in the November 2012 Order. In addition, the Commission provided a detailed discussion of each party's position and the basis for the Commission's decision regarding the ADITs and the Minimum Adjustment on pages 14-17 of the Order. The Commission discussion focused on the fact that the Commission has historically recognized deferred federal income tax expense for rate recovery at the statutory FIT rate applied to the gross tax over book depreciation expense (either present in the test-year or, as in this case, based on the forecasted tax depreciation provided by Mountaineer). Contrary to Mountaineer's argument, this is not a flow through to current customers of the benefit of accelerated depreciation. Just the opposite, the consistent approach of the Commission has been to normalize those tax benefits for ratemaking purposes. The deferred tax expense is included in customer rates, but because the Company does not have to immediately pay that tax to the government, a deferred tax credit is created on the Company's books. Normalization requires customers to pay rates that include a deferred tax component, but it does not prevent the Commission from using the deferred tax credit as a rate base reduction. Taking that rate base deduction does not convert normalization ratemaking that we have historically followed into a flow-through of the benefits of accelerated depreciation to the customer as claimed by Mountaineer in its Limited Petition for Reconsideration.

The Commission stated in the November 2012 Order and continues to believe that its historical method of determining the level of deferred income tax expense for rate recovery meets the normalization requirements of the IRS. The Commission explained that the Mountaineer claim that actual current deferred income tax expense recorded on the Mountaineer books after 2004 exceeded the level of current deferred federal income tax expense recognized in Case No. 04-1595-G-42T (2004 Rate Case) and Case No. 09-0878-G-42T (2009 Rate Case) did not support the inclusion of the Minimum Adjustment to offset the per books normalization rate base deduction. Mountaineer's claim of a difference between the amount of deferred income tax expense built into rates and amounts recorded on the books in subsequent years is not on point with the normalization violation arguments made by Mountaineer. Comparing deferred income tax expense recovered in rates and deferred income tax expense recorded on the books is the same as comparing any cost of service element included for rate recovery to actual amounts recorded in subsequent years and arguing for some kind of true-up. It would be the equivalent of determining that depreciation expense built into rates exceeds actual depreciation booked after the test-year and that the customers were entitled to an immediate rate credit or an adjustment reducing rate base in future rate cases. The Commission explained that such adjustments would constitute a "single issue" and "retro-active" rate adjustment which is contrary to the Commission's base rate process. In fact, actual "retroactive" adjustments when setting base rates, or adjustments that contained an element of retroactivity were addressed and precluded by the Supreme Court of West Virginia decisions in C & P Tel. Co. of West Va. v. West Va. Pub. Ser. Comm'n, 171 W. Va. 494, 300 S.E. 2d 607, 619 (1982). Single issue ratemaking was addressed by the Court and disallowed in VEPCO. v. West Va. Pub. Ser. Comm'n, 162 W.Va. 202, 248 S.E.2d 322 (1978) (syl. pt. 3).

The Commission finds that the decision regarding ADITs and the Minimum Adjustment, as explained in the November 2012 Order, was supported by the record in this case, and was fully and adequately addressed in that Order.

B. Impact on the Company and Its Customers

In the Limited Petition for Reconsideration, Mountaineer argues that the Commission failure to recognize the Minimum Adjustment may create an IRS normalization violation. Mountaineer argues that a normalization violation, if the IRS determined the Commission actions created such a violation, would have an adverse impact on both the Company and its customers. A normalization violation could result in Mountaineer being (i) prohibited from claiming accelerated depreciation deductions for federal income taxes in the future, (ii) required to pay the $15.7 million of deferred federal income tax liability immediately to the IRS, increasing the rate base on which customer rates are established, and (iii) charged various interest charges and penalties by the IRS, all of which would result in higher rates to Mountaineer's customers. Mountaineer also argues that the Commission November 2012 Order is not consistent with decisions in other regulatory jurisdictions. Mountaineer relies heavily on the testimony of CAD witness Ralph Smith concerning an accounting methodology regarding NOLs related to accelerated depreciation presented by KMPG at the 2011 NARUC Fall Accounting Conference in Denver, Colorado and IRS Private Letter Ruling 8818040. CAD Ex. RCS-D, p.10-26, Ex. LA-3 and Ex. LA-2, p. 21-23, and Limited Petition for Reconsideration, Ex. 1.

The Commission reviewed and considered the KMPG Presentation and the IRS Private Letter Ruling 8818040 in arriving at its decision regarding ADITs in the November 2012 Order.

The KMPG presentation indicates that to the extent NOLs are driven by tax over book depreciation deductions, under GAAP accounting, a Company should record the current year deferred federal income tax expense only to the extent the tax over book depreciation reduces the current tax liability to zero. As shown in RCS-D, Ex. LA-3, the accounting entries to record the impact of tax over book depreciation will first debit current deferred federal income tax expense for the federal income tax effect on the gross current year tax over book deprecation deduction and credit ADITs. Then, the federal income tax effect on the current year tax over book depreciation deduction that exceeds pre-depreciation taxable income, if any, will be recorded as a credit (reduction) to current year deferred federal income tax expense and a debit (reduction) or offset to ADITs recorded based on the gross current year tax over book depreciation deduction. This net approach that results in lower deferred federal income tax expense and lower ADITS is not the ratemaking approach used by the Commission. When the Commission sets rates in a base rate case, the deferred income tax expense is calculated based on the statutory tax rate times the gross (full) tax over book depreciation deduction. This is a critical distinction between GAAP accounting and normalization ratemaking.

The GAAP accounting entries result in net current deferred federal income tax expense related to the current year tax over book depreciation expense being equal to the amount realized in the current year federal income tax return. The offset (debit) to ADITs related to the current year tax over book depreciation resulting in NOLs will be reversed once that tax benefit is realized when the NOLs are used to reduce positive taxable income in future federal income tax returns. In the years the NOLs are realized by reducing pre-NOL positive taxable income, GAAP accounting would require that current deferred federal income tax expense be debited (increased) and the ADIT account be credited (increased) to reverse the ADIT offset recorded in prior years. In the Mountaineer case, the offset to the ADITs is recorded as a deferred asset and comprises the $2.6 million Minimum Adjustment to ADITs proposed by Mountaineer in this case.

The Commission notes that the accounting facts leading to the IRS decision in Private Letter Ruling 8818040 are different from the accounting facts behind the Minimum Adjustment to ADITs proposed by Mountaineer. The Private Letter Ruling clearly states that it is directed to the taxpayer that requested the ruling and may not be used or cited as precedent. The accounting situation addressed in the Private Letter Ruling was related to a change in federal income tax rates and addressed what tax rate should be applied in recording current deferred federal income tax expense related to NOL carry-forwards (driven by prior-year, un-realized tax over book depreciation deductions). Although the Private Letter Ruling does not provide a definitive answer or precedent for the Commission in this case, the Commission notes that the Private Letter Ruling is consistent with the KMPG Presentation on GAAP accounting for NOLs related to unrealized tax over book depreciation deductions. The IRS determined that current deferred income tax expense should be recorded in the year the tax deduction giving rise to the NOL is realized. In future years, the NOL is used to offset positive taxable income, and the tax impact is calculated at the tax rate in effect when that tax benefit is realized in the tax return.

In further review of the Private Letter Ruling and the KMPG Presentation, the Commission is not persuaded by the Mountaineer arguments that its treatment of ADITs and current deferred income tax expense used in setting the Company rates in the November 2012 Order is unreasonable or creates a normalization violation; moreover, even if the Commission were inclined to make an adjustment, the Commission finds the

Minimum Adjustment that increases rate base as proposed by Mountaineer only recognizes one-side of the accounting entries described in the KMPG Presentation.

Although Mountaineer proposes to reduce the per books $15.7 million ADIT reduction to rate base by $2.6 million for the Minimum Adjustment, Mountaineer does not propose in this case (and the Commission has never recognized) the corresponding credit (reduction) to deferred federal income tax expense in this case or prior Mountaineer rate cases as would be required under the GAAP accounting methodology described in the KMPG Presentation. In this case the Commission established the federal income tax expense by recognizing $1.302 million of deferred income tax expense as determined by applying the statutory 35 percent FIT rate to the gross tax over book depreciation deduction proposed by Mountaineer ($3.7 million forecasted tax over book depreciation deduction times 35 percent FIT rate) as it has done in prior contested rate cases. Because the Commission has established Mountaineer's rates recognizing gross tax over book depreciation to determine current deferred federal income tax expense, the Commission has built into customer rates a level of deferred income tax that have been paid by customers that have yet to be paid to the IRS.

If the Commission were to adopt Mountaineer's position on the Minimum Adjustment to ADITs, the Commission would also have to credit or reduce the $1.302 million of current deferred federal income taxes used in this case by $2.6 million because the offset to current deferred federal income tax related to NOLs required by the accounting entries described in the KMPG Presentation have not been reflected in customer rates in previous Mountaineer rate cases or the customer rates authorized by the Commission in this proceeding. Thus, considering both sides of the accounting adjustment proposed by Mountaineer would result in a reduction in net deferred income tax expense that would more than offset the increased revenue requirement of including the Minimum Adjustment to ADITs (increasing rate base) proposed by Mountaineer. That ratemaking approach would also require a complicated accounting reconciliation mechanism for adjusting deferred income tax expense in the future with offsetting credits to the ADITs used for rate base reduction purposes.

The Commission finds that calculating a deferred federal income tax expense for rate recovery based on the gross tax over book depreciation deductions for rate recovery is consistent with IRS normalization requirements and supports the Commission decision to include the full $15.7 million of ADITs in rate base as determined from the gross tax over book depreciation deductions. The Commission will not grant the recognition of the Minimum Adjustment to ADITs to increase rate base. Neither will we reduce current deferred federal income tax expense for the unrealized tax over book depreciation deduction required to comply with the accounting treatment shown in the KMPG Presentation.

C. Request For Private Letter Ruling

The Commission rejects Mountaineer's proposal to order Mountaineer to seek a Private Letter Ruling from the IRS. The decision of whether to seek a Private Letter Ruling is one to be made by Mountaineer. We do not believe, however, that there is any need for such a Ruling since there is no normalization violation in the methodology used by the Commission to calculate income taxes for ratemaking purposes. As described in detail above, the Commission finds that its method of calculating deferred income tax expense for ratemaking based on the gross tax over book depreciation adjustment meets the IRS normalization requirements and Mountaineer's proposal to recognize only one side of the U.S. GAAP accounting entries related to recording tax over book depreciation deductions embedded in NOLs in the rate setting process does not meet the IRS normalization requirements.

FINDINGS OF FACT

1. A normalization violation, if the IRS determined the Commission's decision related to the Minimum Adjustment to ADIT created such a violation, would have an adverse impact on both the Company and its customers.

2. The Commission reviewed and considered the KMPG Presentation and the IRS Private Letter Ruling 8818040 in arriving at its decision regarding ADITs in the November 2012 Order.

3. The KMPG presentation indicates that to the extent NOLs are driven by tax over book depreciation deductions, under GAAP accounting, a Company should record the current year deferred federal income tax expense only to the extent the tax over book depreciation reduces the current tax liability to zero.

4. Private Letter Ruling 8818040 addresses the appropriate tax rate to apply to the difference between book and tax depreciation when tax rates have changed between the year of the depreciation deduction and the year that the deduction is included in determining taxable income.

5. Private Letter Ruling 8818040 determined that current deferred income tax expense should be recorded in the year the tax deduction giving rise to the NOL is realized.

6. The Minimum Adjustment that increases rate base as proposed by Mountaineer only recognizes one-side of the accounting entries described in the KMPG Presentation.

7. The Commission has historically established Mountaineer rates recognizing gross tax over book depreciation to determine current deferred federal income tax expense.

8. The Commission has built into customer rates a level of deferred income tax expense based on the gross tax over book depreciation deduction that has been paid by customers but have yet to be paid to the IRS.

CONCLUSIONS OF LAW

1. The Commission's decision regarding ADITs and the Minimum Adjustment, as explained in the November 2012 Order, was supported by the record in this case, is reasonable, and was fully and adequately addressed in that Order.

2. The Commission is not persuaded by the Mountaineer arguments that its treatment of ADITs and current deferred income tax expense used in setting the Company rates in the November 2012 Order is unreasonable or creates a normalization violation.

3. The Commission calculation of deferred federal income tax expense for rate recovery based on the gross tax over book depreciation deductions for rate recovery is consistent with IRS normalization requirements and supports the Commission decision to include the full \$15.7 million of ADITs in rate base as determined from the gross tax over book depreciation deductions.

4. The Mountaineer proposal to recognize only one side of the U.S. GAAP accounting entries related to recording tax over book depreciation deductions embedded in NOLs in the rate setting process is inconsistent with the normalization ratemaking consistently followed by the Commission.

5. The decision of whether to seek a Private Letter Ruling is one to be made by Mountaineer.

ORDER

IT IS THEREFORE ORDERED that that the Commission rejects the Limited Petition for Reconsideration.

IT IS FURTHER ORDERED that the Commission Order issued on October 31, 2012, as revised on November 5, 2012, is affirmed.

IT IS FURTHER ORDERED that upon entry of this Order this case shall be removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste: Sandra Squire

Sandra Squire
Executive Secretary

CLW/sk
111627cf.doc

Current Rates

	Distribution Charge Per Mcf	GCA Per Mcf	Total Per Mcf	Average Annual Mcf	Annual Variable Charges	Monthly Customer Charge	Annual Customer Charge	Monthly PRP Charge	Annual PRP Charge	Average Annual Bill	
Atmos Energy	$ 1.10	$ 5.70	$ 6.80	65	$ 441.84	$ 12.50	$ 150.00	$ 2.61	$ 31.32	$ 623.16	1
Columbia	$ 2.27	$ 6.51	$ 8.78	65	$ 570.65	$ 15.00	$ 180.00	$ -	$ -	$ 750.65	3
Delta	$ 4.32	$ 7.59	$ 11.91	65	$ 774.28	$ 20.70	$ 248.40	$ 1.19	$ 14.28	$ 1,036.96	5
Duke	$ 3.72	$ 5.14	$ 8.87	65	$ 576.24	$ 16.00	$ 192.00	$ -	$ -	$ 768.24	4
LG&E	$ 2.64	$ 5.17	$ 7.82	65	$ 508.01	$ 13.50	$ 162.00	$ 2.27	$ 27.24	$ 697.25	2

Proposed Rates

	Distribution Charge Per Mcf	GCA Per Mcf	Total Per Mcf	Average Annual Mcf	Annual Variable Charges	Monthly Customer Charge	Annual Customer Charge	Monthly PRP Charge	Annual PRP Charge	Average Annual Bill	
Atmos Energy	$ 1.63	$ 5.70	$ 7.33	65	$ 476.29	$ 16.00	$ 192.00	$ -	$ -	$ 668.29	1
Columbia	$ 2.27	$ 6.51	$ 8.78	65	$ 570.65	$ 15.00	$ 180.00	$ -	$ -	$ 750.65	3
Delta	$ 4.32	$ 7.59	$ 11.91	65	$ 774.28	$ 20.70	$ 248.40	$ 1.19	$ 14.28	$ 1,036.96	5
Duke	$ 3.72	$ 5.14	$ 8.87	65	$ 576.24	$ 16.00	$ 192.00	$ -	$ -	$ 768.24	4
LG&E	$ 2.64	$ 5.17	$ 7.82	65	$ 508.01	$ 13.50	$ 162.00	$ 2.27	$ 27.24	$ 697.25	2

Proposed rates capture 100% of our ask.

ATMOS – EXHIBIT 1

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2013-00148
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended July 31, 2013

Data:___X____Base Period________Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(13)(c)2.2
Schedule C-2.2
Witness: Densman, Martin

Line No.	Acct No.	Account Discription	actual Aug-12	actual Sep-12	actual Oct-12	actual Nov-12	actual Dec-12	actual Jan-13	actual Feb-13	Budgeted Mar-13	Budgeted Apr-13	Budgeted May-13	Budgeted Jun-13	Budgeted Jul-13	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
6	4800	Residential sales	(2,949,553)	(2,798,419)	(3,835,537)	(6,920,516)	(9,698,940)	(13,817,989)	(13,757,430)	(10,321,399)	(7,657,292)	(5,165,176)	(3,590,539)	(3,276,797)	(83,789,588)
7	4805	Unbilled Residential Revenue	(24,015)	8,404	(872,088)	(2,118,411)	(1,773,976)	(1,743,476)	1,575,941						(4,947,620)
8	4811	Commercial Revenue-Banner	(1,403,372)	(1,357,128)	(1,720,155)	(2,572,492)	(3,636,786)	(5,387,021)	(5,456,377)	(3,892,461)	(2,984,154)	(2,270,525)	(1,746,094)	(1,629,290)	(34,055,854)
9	4812	Industrial Revenue-Banner	(396,462)	(392,809)	(428,998)	(440,596)	(461,727)	(656,353)	(670,585)	(390,265)	(214,786)	(222,180)	(177,049)	(146,899)	(4,598,709)
10	4815	Unbilled Comm Revenue	(60,209)	(4,266)	(479,685)	(512,168)	(698,148)	(757,809)	599,908						(1,912,377)
11	4820	Other Sales to Public Authorities	(206,771)	(209,850)	(333,413)	(579,613)	(868,672)	(1,207,500)	(1,230,627)	(898,532)	(648,396)	(418,896)	(269,106)	(242,031)	(7,113,407)
12	4825	Unbilled Public Authority Revenue	(7,634)	(3,027)	(139,905)	(154,529)	(189,209)	(128,826)	144,583						(478,547)
13	4870	Forfeited discounts	(40,285)	(34,141)	(40,064)	(62,672)	(102,392)	(123,598)	(163,882)	(123,852)	(92,543)	(64,394)	(45,959)	(42,207)	(935,987)
14	4880	Miscellaneous service revenues	(56,114)	(64,806)	(124,593)	(104,846)	(64,356)	(58,648)	(56,573)	(49,210)	(47,570)	(49,815)	(48,845)	(44,569)	(769,945)
15	4893-6	Revenue-Transportation Distribution	(861,783)	(831,455)	(1,009,858)	(1,049,492)	(1,052,718)	(1,244,401)	(1,111,196)	(855,173)	(791,624)	(801,196)	(757,673)	(716,884)	(11,083,453)
16	4895	Revenue-Transportation Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
17	4896	Revenue-Transportation Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
18	4950	Other Gas Revenue	0	0	0	0	0	0	0	(122,769)	(123,770)	(122,302)	(121,534)	(118,120)	(608,495)
		Total Revenue	(6,006,197)	(5,687,496)	(8,984,296)	(14,515,335)	(18,546,924)	(25,125,620)	(20,126,238)	(16,653,660)	(12,560,135)	(9,114,485)	(6,756,800)	(6,216,797)	(150,293,982)
		Gas Cost	1,911,535	1,628,939	3,941,415	8,617,495	11,273,608	16,755,309	13,028,117	10,316,766	7,058,695	4,362,961	2,468,087	2,076,533	83,439,461
		Margin	(4,094,662)	(4,058,556)	(5,042,881)	(5,897,840)	(7,273,315)	(8,370,311)	(7,098,121)	(6,336,894)	(5,501,440)	(4,751,525)	(4,288,712)	(4,140,264)	(66,854,521)

All Actual Monthly Results

Line No.	Acct No.	Account Discription	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total	variance	% variance
6	4800	Residential sales	(2,949,553)	(2,798,419)	(3,835,537)	(6,920,516)	(9,698,940)	(13,817,989)	(13,757,430)	(12,310,138)	(9,027,144)	(6,567,911)	(3,815,397)	(3,400,497)	(88,899,472)	(405,111)	0.5%
7	4805	Unbilled Residential Revenue	(24,015)	8,404	(872,088)	(2,118,411)	(1,773,976)	(1,743,476)	1,575,941	317,618	2,542,789	1,576,492	221,349	46,526	(242,847)		
8	4811	Commercial Revenue-Banner	(1,403,372)	(1,357,128)	(1,720,155)	(2,572,492)	(3,636,786)	(5,387,021)	(5,456,377)	(4,903,029)	(3,536,220)	(2,590,550)	(1,794,680)	(1,589,644)	(35,947,453)	(117,359)	0.3%
9	4812	Industrial Revenue-Banner	(396,462)	(392,809)	(428,998)	(440,596)	(461,727)	(656,353)	(670,585)	(527,222)	(390,648)	(253,249)	(209,980)	(155,227)	(4,983,856)	(385,147)	8.4%
10	4815	Unbilled Comm Revenue	(60,209)	(4,266)	(479,685)	(512,168)	(698,148)	(757,809)	599,908	110,692	1,097,066	670,403	(97,269)	(6,652)	(138,137)		
11	4820	Other Sales to Public Authorities	(206,771)	(209,850)	(333,413)	(579,613)	(868,672)	(1,207,500)	(1,230,627)	(1,073,114)	(800,157)	(475,568)	(314,083)	(324,007)	(7,623,374)	(92,658)	1.3%
12	4825	Unbilled Public Authority Revenue	(7,634)	(3,027)	(139,905)	(154,529)	(189,209)	(128,826)	144,583	38,921	243,485	173,159	(9,724)	(28,532)	(61,238)		0.0%
13	4870	Forfeited discounts	(40,285)	(34,141)	(40,064)	(62,672)	(102,392)	(123,598)	(163,882)	(123,562)	(81,928)	5	2	0	(772,514)	163,473	-17.5%
14	4880	Miscellaneous service revenues	(56,114)	(64,806)	(124,593)	(104,846)	(64,356)	(58,648)	(56,573)	(42,383)	(49,036)	(40,496)	(31,998)	(36,386)	(730,234)	39,711	-5.2%
15	4893-6	Revenue-Transportation Distribution	(861,783)	(831,455)	(1,009,858)	(1,049,492)	(1,052,718)	(1,244,401)	(1,111,196)	(1,177,396)	(1,013,911)	(893,294)	(900,931)	(903,962)	(12,050,397)	(966,945)	8.7%
16	4895	Revenue-Transportation Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0%
17	4896	Revenue-Transportation Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0%
18	4950	Other Gas Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	608,495	-100.0%
		Imputed forfeited Discounts													0		
		Total Revenue	(6,006,197)	(5,687,496)	(8,984,296)	(14,515,335)	(18,546,924)	(25,125,620)	(20,126,238)	(19,689,612)	(11,015,704)	(8,401,010)	(6,952,712)	(6,398,381)	(151,449,523)	(1,155,542)	0.8%
		Gas Cost	1,911,535	1,628,939	3,941,415	8,617,495	11,273,608	16,755,309	13,028,117	13,067,034	5,823,140	3,885,481	2,667,374	2,197,413	84,796,859	1,357,399	1.6%
		Margin	(4,094,662)	(4,058,556)	(5,042,881)	(5,897,840)	(7,273,315)	(8,370,311)	(7,098,121)	(6,622,578)	(5,192,564)	(4,515,529)	(4,285,338)	(4,200,968)	(66,652,664)	201,857	-0.3%

ATMOS – EXHIBIT 2

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2013-00148
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended July 31, 2013

Data:__X__Base Period______Forecasted Period
Type of Filing:__X__Original______Updated ______Revised
Workpaper Reference No(s).

FR 16(13)(c)2.2
Schedule C-2.2
Witness: Densman, Martin

Line No.	Acct No.	Account Discription	actual Aug-12	actual Sep-12	actual Oct-12	actual Nov-12	actual Dec-12	actual Jan-13	actual Feb-13	Budgeted Mar-13	Budgeted Apr-13	Budgeted May-13	Budgeted Jun-13	Budgeted Jul-13	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
3	4030	Depreciation Expense	1,156,878	1,252,601	1,172,852	1,176,738	1,185,297	1,189,466	1,198,090	1,250,198	1,258,488	1,318,119	1,280,693	1,296,779	14,736,199
4	4060	Amortization of gas plant acquisition adjustments	4,523	4,523	4,878	4,878	4,878	4,878	4,878	0	0	0	0	0	33,434
5	4081	Taxes other than income taxes, utility operating inco	361,527	329,871	363,325	389,033	358,671	392,814	357,566	345,446	408,691	334,896	342,049	363,069	4,346,957
36	8140	Storage-Operation supervision and engineering	(299)	(841)	271	(299)	(279)	(279)	(279)	(21)	(571)	(21)	(18)	(575)	(3,211)
37	8160	Wells expenses	3,183	(53)	14,320	25,291	21,102	6,000	5,068	12,639	13,438	13,604	12,669	12,911	140,173
38	8170	Lines expenses	3,103	3,308	1,555	7,562	4,466	4,516	5,968	4,888	5,001	5,272	4,603	5,242	55,483
39	8180	Compressor station expenses	411	683	2,545	3,911	1,254	1,307	839	2,003	2,049	2,127	1,917	2,117	21,163
40	8190	Compressor station fuel and power	54	33	56	63	0	129	66	66	66	66	66	66	731
41	8200	Storage-Measuring and regulating station expenses	(18)	782	261	142	520	607	376	393	398	411	380	409	4,662
42	8210	Storage-Purification expenses	85	104	114	604	760	5,957	6,199	2,770	2,833	2,962	2,631	2,947	27,966
43	8240	Storage-Other expenses	17	19	19	19	0	27	25	19	19	19	19	19	221
44	8250	Storage well royalties	116	411	711	389	896	1,684	2,216	1,141	1,353	1,138	1,140	1,354	12,549
45	8310	Storage-Maintenance of structures and improvemen	0	0	0	2,527	0	1,864	0	811	869	829	831	829	8,561
46	8340	Maintenance of compressor station equipment	0	178	(59)	1,231	1,121	(295)	0	406	415	438	381	436	4,252
47	8350	Maintenance of measuring and regulating station eq	358	(119)	0	0	0	0	0	0	0	0	0	0	238
48	8360	Processing-Maintenance of purification equipment	0	0	0	329	(41)	2	0	59	60	63	56	63	592
49	8500	Transmission-Operation supervision and engineerin	0	0	0	0	0	0	0	0	0	0	0	0	0
50	8560	Mains expenses	15,447	9,069	20,291	24,625	132,832	24,574	14,397	36,555	41,055	39,010	37,119	38,898	433,873
51	8570	Transmission-Measuring and regulating station expe	7,078	6,002	8,071	7,722	11,733	6,896	6,341	8,304	8,479	8,878	7,881	8,833	96,217
52	8630	Transmission-Maintenance of mains	3,812	6,385	6,033	(1,108)	1,170	129	1,893	1,562	1,644	1,685	1,500	1,677	26,380
53	8650	Transmission-Maintenance of measuring and regula	0	0	0	111	95	0	178	80	81	83	78	83	788
54	8670	Transmission-Maintenance of other equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
55	8700	Distribution-Operation supervision and engineering	100,128	96,323	97,661	110,420	157,391	127,640	85,332	109,887	110,890	112,792	103,452	111,332	1,323,247
56	8710	Distribution load dispatching	3	37	19	19	19	40	22	25	25	25	25	25	283
57	8711	Odorization	625	420	0	0	0	1,286	0	274	274	274	274	274	3,699
58	8740	Mains and Services Expenses	228,241	240,684	245,166	199,584	208,865	229,307	242,776	230,412	246,976	243,196	229,489	248,390	2,793,086
59	8750	Distribution-Measuring and regulating station expen:	27,463	23,927	20,172	22,302	16,368	26,203	20,670	21,534	21,868	22,849	20,313	22,752	266,421
60	8760	Distribution-Measuring and regulating station expen:	4,873	5,319	2,022	2,675	(604)	3,083	2,200	1,904	1,948	2,056	1,791	2,044	29,310
61	8770	Distribution-Measuring and regulating station expen:	20,644	16,641	2,928	5,036	5,660	11,663	5,212	6,314	6,397	6,601	6,099	6,578	99,773
62	8780	Meter and house regulator expenses	57,588	63,305	65,642	69,201	61,923	73,639	53,084	65,638	67,062	70,630	61,858	70,227	779,796
63	8790	Customer installations expenses	731	1,288	(80)	1,942	1,473	4,687	6	1,634	1,670	1,758	1,543	1,748	18,401
64	8800	Distribution-Other expenses	5,421	2,966	11,623	4,930	378	7,558	30,562	11,405	11,427	11,950	10,499	11,883	120,600
65	8810	Distribution-Rents	33,850	38,870	32,221	34,424	30,746	41,219	35,264	36,569	36,481	36,487	36,600	36,475	429,207
66	8850	Distribution-Maintenance supervision and engineerir	577	164	197	313	218	142	259	221	218	218	221	218	2,963
67	8860	Distribution-Maintenance of structures and improver	433	2,298	119	954	283	296	103	369	368	368	369	368	6,329
68	8870	Distribution-Maint of mains	7,091	31,776	1,311	2,530	2,562	5,464	2,499	2,914	2,983	3,152	2,736	3,133	68,151
69	8890	Maintenance of measuring and regulating station eq	1,599	0	2,709	0	0	0	0	577	577	577	577	577	7,192
70	8900	Maintenance of measuring and regulating station eq	1,166	93	0	0	0	0	2,409	513	513	513	513	513	6,234
71	8910	Maintenance of measuring and regulating station eq	1,357	2,900	0	0	1,828	0	0	389	389	389	389	389	8,031
72	8920	Maintenance of services	866	1,095	957	1,644	358	1,409	1,055	1,100	1,126	1,190	1,033	1,183	13,015
73	8930	Maintenance of meters and house regulators	9,131	1,337	7,246	20	3,209	4,061	4,665	3,894	3,987	4,212	3,657	4,187	49,607
74	8940	Distribution-Maintenance of other equipment	1,104	2,112	2,198	1,326	1,041	986	183	1,210	1,206	1,202	1,201	1,200	14,969
75	9010	Customer accounts-Operation supervision	41	1,875	(109)	0	0	0	29	(16)	(16)	(18)	(15)	(18)	1,753
76	9020	Customer accounts-Meter reading expenses	101,289	105,441	102,822	127,043	102,674	139,472	110,756	94,096	109,077	101,675	96,661	101,450	1,292,457
77	9030	Customer accounts-Customer records and collectior	37,929	29,626	29,242	22,976	25,379	31,031	32,876	28,635	29,266	30,799	27,012	30,625	355,396
78	9040	Customer accounts-Uncollectible accounts	15,288	63,979	21,597	26,207	34,035	38,921	32,234	27,006	19,462	16,994	16,254	15,993	327,970
79	9070	Customer service-Supervision	0	0	0	0	0	0	0	0	0	0	0	0	0
80	9080	Customer service-Operating assistance expense	0	0	0	0	0	0	0	0	0	0	0	0	0
81	9090	Customer service-Operating informational and instru	9,457	9,946	16,627	13,741	9,261	9,709	8,778	10,111	10,366	10,635	9,581	10,779	128,990
82	9100	Customer service-Miscellaneous customer service	0	0	0	0	0	0	0	0	0	0	0	0	0
83	9110	Sales-Supervision	20,225	17,223	20,302	17,801	17,190	19,313	16,328	17,131	17,062	17,795	16,340	17,711	214,421
84	9120	Sales-Demonstrating and selling expenses	2,865	11,354	3,251	16,671	18,434	9,848	3,925	4,601	4,512	4,505	4,505	4,505	88,974
85	9130	Sales-Advertising expenses	275	320	2,140	823	131	1,986	1,431	579	579	579	579	579	10,001
86	9160	Sales-Miscellaneous sales expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
87	9200	A&G-Administrative & general salaries	31,047	29,975	33,613	31,454	29,451	32,767	28,489	31,593	32,349	34,175	29,672	33,973	378,559
88	9210	A&G-Office supplies & expense	(588)	(519)	(1,056)	(170)	(665)	353	(1,266)	236	(2,559)	194	252	(2,593)	(8,381)
89	9220	A&G-Administrative expense transferred-Credit	839,146	1,020,329	661,945	781,218	950,373	866,865	865,163	1,013,491	959,129	1,026,553	915,351	977,284	10,876,844
90	9230	A&G-Outside services employed	23,477	27,013	12,573	22,560	18,576	9,822	10,284	10,594	13,177	11,455	11,455	11,455	182,440
91	9240	A&G-Property insurance	12,480	11,814	12,711	12,436	12,442	12,762	13,501	877	877	877	877	877	92,533
92	9250	A&G-Injuries & damages	1,377	700,338	1,294	2,071	4,081	277	757	1,304	1,526	1,385	1,364	1,373	717,148
93	9260	A&G-Employee pensions and benefits	186,844	162,462	275,597	226,124	241,327	288,369	248,912	261,276	267,981	281,918	245,598	280,344	2,966,753
94	9270	A&G-Franchise requirements	1,459	0	67	123	690	335	1,029	67	946	67	62	951	5,797
95	9280	A&G-Regulatory commission expenses	15,275	15,275	15,275	15,275	15,275	15,275	22,326	3,302	33,443	3,384	3,203	33,459	190,770
96	9301	A&G-General advertising expense	0	0	0	0	0	0	0	0	0	0	0	0	0
97	9302	Miscellaneous general expenses	5,375	15	30	825	2,360	13,952	1,570	8,777	2,265	1,707	1,707	1,707	40,289
98	9310	A&G-Rents	2,644	2,636	2,686	2,686	2,686	3,698	2,939	3,091	3,083	3,084	3,093	3,083	35,409
99															
100		Total	$3,365,070	$4,353,612	$3,297,961	$3,420,951	$3,699,892	$3,673,717	$3,490,180	$3,680,852	$3,763,278	$3,797,780	$3,560,187	$3,782,188	$43,885,667

ATMOS – EXHIBIT 3

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2013-00148
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended July 31, 2013

Data:__X___Base Period_______Forecasted Period
Type of Filing:___X____Original_______Updated _______Revised
Workpaper Reference No(s).

FR 16(13)(c)2.2
Schedule C-2.2
Witness: Densman, Martin

Line No.	Acct No.	Account Discription	actual Aug-12	actual Sep-12	actual Oct-12	actual Nov-12	actual Dec-12	actual Jan-13	actual Feb-13	actual Mar-13	actual Apr-13	actual May-13	actual Jun-13	actual Jul-13	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
3	4030	Depreciation Expense	1,156,878	1,252,601	1,172,852	1,176,738	1,185,297	1,189,466	1,198,090	1,200,071	1,204,581	1,216,248	1,225,096	1,236,752	14,414,669
4	4060	Amortization of gas plant acquisition adjustments	4,523	4,523	4,878	4,878	4,878	4,878	4,878	4,878	6,675	6,704	6,704	6,704	65,098
5	4081	Taxes other than income taxes, utility operating inco	361,527	329,871	363,325	389,033	358,671	392,814	357,566	363,194	396,827	427,292	344,540	362,901	4,447,560
36	8140	Storage-Operation supervision and engineering	(299)	(841)	271	(299)	(279)	(279)	(279)	(448)	(279)	(299)	(279)	(279)	(3,588)
37	8160	Wells expenses	3,183	(53)	14,320	25,291	21,102	6,000	5,068	4,877	7,744	5,113	15,619	3,052	111,316
38	8170	Lines expenses	3,103	3,308	1,555	7,562	4,466	4,516	5,968	3,781	4,767	4,193	3,688	4,150	51,056
39	8180	Compressor station expenses	411	683	2,545	3,911	1,254	1,307	839	478	3,124	4,493	734	969	20,749
40	8190	Compressor station fuel and power	54	33	56	63	0	129	66	71	67	67	38	59	703
41	8200	Storage-Measuring and regulating station expenses	(18)	782	261	142	520	607	376	268	1,322	101	429	(49)	4,741
42	8210	Storage-Purification expenses	85	104	114	604	760	5,957	6,199	2,013	5,472	(861)	475	80	21,003
43	8240	Storage-Other expenses	17	19	19	19	0	27	25	21	21	21	20	19	229
44	8250	Storage well royalties	116	411	711	389	896	1,684	2,216	1,390	1,179	666	992	133	10,783
45	8310	Storage-Maintenance of structures and improvemen	0	0	0	2,527	0	1,864	0	0	80	0	211	497	5,180
46	8340	Maintenance of compressor station equipment	0	178	(59)	1,231	1,121	(295)	0	0	0	787	149	923	4,035
47	8350	Maintenance of measuring and regulating station eq	358	(119)	0	0	0	0	0	0	0	0	422	(74)	587
48	8360	Processing-Maintenance of purification equipment	0	0	0	329	(41)	2	0	0	0	0	2,011	341	2,642
49	8500	Transmission-Operation supervision and engineerin	0	0	0	0	0	0	0	294	0	0	0	0	294
50	8560	Mains expenses	15,447	9,069	20,291	24,625	132,832	24,574	14,397	25,140	22,231	11,835	8,640	17,249	326,331
51	8570	Transmission-Measuring and regulating station expe	7,078	6,002	8,071	7,722	11,733	6,896	6,341	9,774	3,440	7,406	5,530	5,791	85,783
52	8630	Transmission-Maintenance of mains	3,812	6,385	6,033	(1,108)	1,170	129	1,893	(333)	(89)	2,416	145	(98)	20,353
53	8650	Transmission-Maintenance of measuring and regula	0	0	0	111	95	0	178	(55)	0	2,174	(282)	0	2,220
54	8670	Transmission-Maintenance of other equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
55	8700	Distribution-Operation supervision and engineering	100,128	96,323	97,661	110,420	157,391	127,640	85,332	126,936	143,160	153,612	92,771	124,998	1,416,371
56	8710	Distribution load dispatching	3	37	19	19	19	40	22	55	19	37	19	40	329
57	8711	Odorization	625	420	0	0	0	1,286	0	2,505	150	0	0	0	4,985
58	8740	Mains and Services Expenses	228,241	240,684	245,166	199,584	208,865	229,307	242,776	243,887	289,372	257,864	243,408	307,185	2,936,338
59	8750	Distribution-Measuring and regulating station expen:	27,463	23,927	20,172	22,302	16,368	26,203	20,670	25,124	26,447	36,377	22,754	31,833	299,640
60	8760	Distribution-Measuring and regulating station expen:	4,873	5,319	2,022	2,675	(604)	3,083	2,200	1,779	4,808	2,140	2,609	2,235	33,139
61	8770	Distribution-Measuring and regulating station expen:	20,644	16,641	2,928	5,036	5,660	11,663	5,212	4,235	4,575	11,464	2,390	8,646	99,093
62	8780	Meter and house regulator expenses	57,588	63,305	65,642	69,201	61,923	73,639	53,084	61,027	72,106	72,579	60,456	70,323	780,871
63	8790	Customer installations expenses	731	1,288	(80)	1,942	1,473	4,687	6	3,183	4,812	1,081	1,117	776	21,017
64	8800	Distribution-Other expenses	5,421	2,966	11,623	4,930	378	7,558	30,562	51,465	57,318	(15,513)	5,230	12,196	174,132
65	8810	Distribution-Rents	33,850	38,870	32,221	34,424	30,746	41,219	35,264	37,382	40,744	32,729	33,337	34,838	425,625
66	8850	Distribution-Maintenance supervision and engineerir	577	164	197	313	218	142	259	154	214	236	31	175	2,678
67	8860	Distribution-Maintenance of structures and improven	433	2,298	119	954	283	296	103	54	984	107	354	54	6,039
68	8870	Distribution-Maint of mains	7,091	31,776	1,311	2,530	2,562	5,464	2,499	3,752	2,867	3,937	4,286	36,625	104,700
69	8890	Maintenance of measuring and regulating station eq	1,599	0	2,709	0	0	0	0	0	0	283	0	0	4,591
70	8900	Maintenance of measuring and regulating station eq	1,166	93	0	0	0	0	2,409	89	0	1,505	7,844	249	13,356
71	8910	Maintenance of measuring and regulating station eq	1,357	2,900	0	0	1,828	0	0	0	0	2,065	108	137	8,394
72	8920	Maintenance of services	866	1,095	957	1,644	358	1,409	1,055	480	1,689	890	570	731	11,744
73	8930	Maintenance of meters and house regulators	9,131	1,337	7,246	20	3,209	4,061	4,665	359	2,349	2,174	9,247	10,659	54,456
74	8940	Distribution-Maintenance of other equipment	1,104	2,112	2,198	1,326	1,041	986	183	1,675	1,180	813	805	1,060	14,481
75	9010	Customer accounts-Operation supervision	41	1,875	(109)	0	0	0	29	0	0	0	0	0	1,836
76	9020	Customer accounts-Meter reading expenses	101,289	105,441	102,822	127,043	102,674	139,472	110,756	143,111	143,913	111,519	105,812	139,247	1,433,100
77	9030	Customer accounts-Customer records and collectior	37,929	29,626	29,242	22,976	25,379	31,031	32,876	34,370	49,502	15,803	18,637	21,649	349,019
78	9040	Customer accounts-Uncollectible accounts	15,288	63,979	21,597	26,207	34,035	38,921	32,234	29,565	22,674	20,307	106,094	18,534	429,435
79	9070	Customer service-Supervision	0	0	0	0	0	0	0	0	0	0	0	0	0
80	9080	Customer service-Operating assistance expense	0	0	0	0	0	0	0	0	0	0	0	0	0
81	9090	Customer service-Operating informational and instru	9,457	9,946	16,627	13,741	9,261	9,709	8,778	8,886	10,119	9,848	10,648	9,785	126,806
82	9100	Customer service-Miscellaneous customer service	0	0	0	0	0	0	0	0	0	0	0	0	0
83	9110	Sales-Supervision	20,225	17,223	20,302	17,801	17,190	19,313	16,328	16,881	17,836	19,741	17,323	18,957	219,120
84	9120	Sales-Demonstrating and selling expenses	2,865	11,354	3,251	16,671	18,434	9,848	3,925	3,999	2,483	9,235	4,070	5,406	91,541
85	9130	Sales-Advertising expenses	275	320	2,140	823	131	1,986	1,431	1,169	1,818	1,139	783	1,891	13,905
86	9160	Sales-Miscellaneous sales expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
87	9200	A&G-Administrative & general salaries	31,047	29,975	33,613	31,454	29,451	32,767	28,489	33,846	37,986	55,332	46,002	52,243	442,205
88	9210	A&G-Office supplies & expense	(588)	(519)	(1,056)	(170)	(665)	353	(1,266)	(1,344)	(697)	(473)	(1,249)	109	(7,565)
89	9220	A&G-Administrative expense transferred-Credit	839,146	1,020,329	661,945	781,218	950,373	866,865	865,163	620,354	1,220,224	842,367	877,752	954,186	10,499,923
90	9230	A&G-Outside services employed	23,477	27,013	12,573	22,560	18,576	9,822	10,284	30,768	11,318	6,951	14,801	5,126	193,268
91	9240	A&G-Property insurance	12,480	11,814	12,711	12,436	12,442	12,762	13,501	14,691	13,670	12,856	12,652	12,635	154,652
92	9250	A&G-Injuries & damages	1,377	700,338	1,294	2,071	4,081	277	757	2,992	2,238	2,180	13	81	717,698
93	9260	A&G-Employee pensions and benefits	186,844	162,462	275,597	226,124	241,327	288,369	248,912	258,296	303,792	239,559	233,153	260,724	2,925,160
94	9270	A&G-Franchise requirements	1,459	0	67	123	690	335	1,029	135	0	0	616	0	4,455
95	9280	A&G-Regulatory commission expenses	15,275	15,275	15,275	15,275	15,275	15,275	22,326	31,284	39,264	41,554	84,710	5,025	315,814
96	9301	A&G-General advertising expense	0	0	0	0	0	0	0	0	0	0	0	0	0
97	9302	Miscellaneous general expenses	5,375	15	30	825	2,360	13,952	1,570	0	3,250	880	10,975	11,800	51,032
98	9310	A&G-Rents	2,644	2,636	2,686	2,686	2,686	3,698	2,939	2,939	3,175	3,680	22,076	3,680	55,526
99															
100		Total with all monthly actuals	$3,365,070	$4,353,612	$3,297,961	$3,420,951	$3,699,892	$3,673,717	$3,490,180	$3,411,498	$4,192,520	$3,645,210	$3,667,086	$3,802,960	$44,020,655
		Total as Filed	3,365,070	4,353,612	3,297,961	3,420,951	3,699,892	3,673,717	3,490,180	3,680,852	3,763,278	3,797,780	3,560,187	3,782,188	43,885,667
		variance	0	0	0	0	0	0	0	(269,354)	429,243	(152,571)	106,898	20,772	134,988
		% variance													0.31%

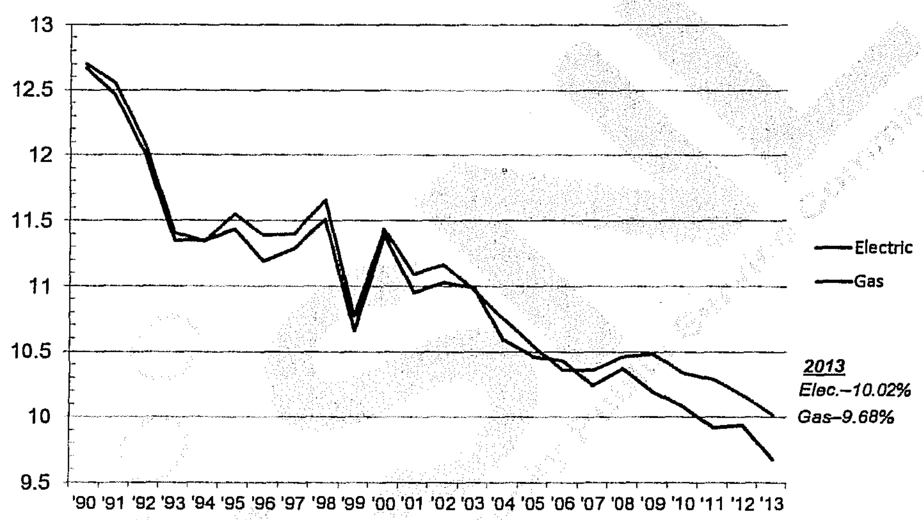
Regulatory Research Associates
REGULATORY FOCUS

January 15, 2014

MAJOR RATE CASE DECISIONS--CALENDAR 2013

The average return on equity (ROE) authorized electric utilities was 10.02% in 2013, compared to 10.17% in 2012. There were 48 electric ROE determinations in 2013, versus 58 in 2012. We note that the data includes several surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding these Virginia surcharge/rider generation cases from the data, the average authorized electric ROE was 9.8% in 2013 compared to 10.01% in 2012. The average ROE authorized gas utilities was 9.68% in 2013 compared to 9.94% in 2012. There were 21 gas cases that included an ROE determination in 2013, versus 35 in 2012. (We note that this report utilizes the simple mean for the return averages.)

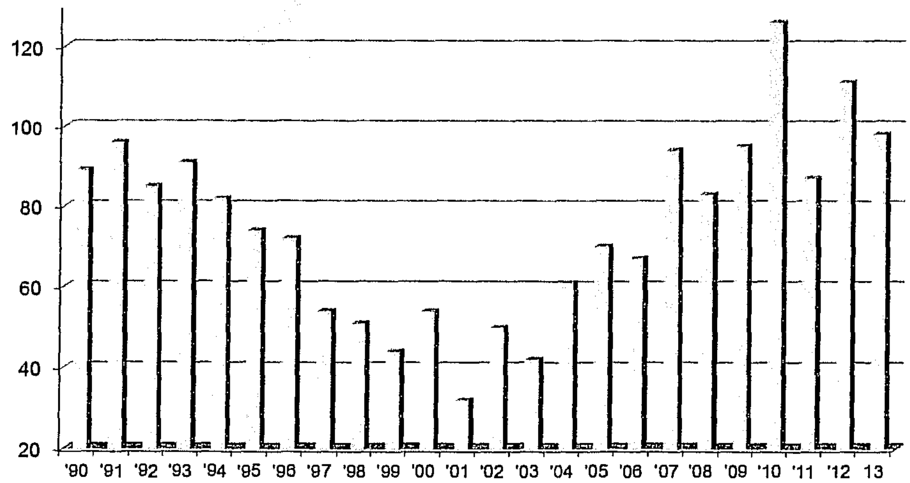
Graph 1: Average Authorized ROEs – Electric and Gas Rate Decisions



Source: SNL Energy/RRA

After reaching a low in the early-2000s, the number of rate case decisions for energy companies has generally increased over the last several years, as shown in Graph 2 below. There were 98 electric and gas rate

Graph 2: Rate Case Decisions – Volume of Electric and Gas Case Decisions



Source: SNL Energy/RRA

PSC – EXHIBIT 1

Average Equity Returns Authorized January 1990 - December 2013

		Electric Utilities		Gas Utilities	
Year	**Period**	**ROE %**	**(# Cases)**	**ROE %**	**(# Cases)**
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
2004	Full Year	10.75	(19)	10.59	(20)
2005	Full Year	10.54	(29)	10.46	(26)
2006	Full Year	10.36	(26)	10.43	(16)
2007	Full Year	10.36	(39)	10.24	(37)
	1st Quarter	10.45	(10)	10.38	(7)
	2nd Quarter	10.57	(8)	10.17	(3)
	3rd Quarter	10.47	(11)	10.49	(7)
	4th Quarter	10.33	(8)	10.34	(13)
2008	**Full Year**	**10.46**	(37)	**10.37**	(30)
	1st Quarter	10.29	(9)	10.24	(4)
	2nd Quarter	10.55	(10)	10.11	(8)
	3rd Quarter	10.46	(3)	9.88	(2)
	4th Quarter	10.54	(17)	10.27	(15)
2009	**Full Year**	**10.48**	(39)	**10.19**	(29)
	1st Quarter	10.66	(17)	10.24	(9)
	2nd Quarter	10.08	(14)	9.99	(11)
	3rd Quarter	10.26	(11)	9.93	(4)
	4th Quarter	10.30	(17)	10.09	(12)
2010	**Full Year**	**10.34**	(59)	**10.08**	(37)
	1st Quarter	10.32	(13)	10.10	(5)
	2nd Quarter	10.12	(10)	9.88	(5)
	3rd Quarter	10.36	(8)	9.65	(2)
	4th Quarter	10.34	(11)	9.88	(4)
2011	**Full Year**	**10.29**	(42)	**9.92**	(16)
	1st Quarter	10.84	(12)	9.63	(5)
	2nd Quarter	9.92	(13)	9.83	(8)
	3rd Quarter	9.78	(8)	9.75	(1)
	4th Quarter	10.10	(25)	10.07	(21)
2012	**Full Year**	**10.17**	(58)	**9.94**	(35)
	1st Quarter	10.24	(15)	9.57	(3)
	2nd Quarter	9.84	(7)	9.47	(6)
	3rd Quarter	10.06	(7)	9.60	(1)
	4th Quarter	9.89	(19)	9.83	(11)
2013	**Full Year**	**10.02**	(48)	**9.68**	(21)

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/9/13	Kansas City Power & Light (MO)	8.13 (E)	9.70	52.30 (E)	9/11-YE	67.4
1/9/13	KCP&L Greater Missouri Op. (L&P) (MO)	8.13 (E)	9.70	52.30 (E)	9/11-YE	21.7
1/9/13	KCP&L Greater Missouri Op. (MPS) (MO)	8.13 (E)	9.70	52.30 (E)	9/11-YE	26.2
1/16/13	Cross Texas Transmission (TX)	7.03	9.60	40.00	6/12-YE	39.5 (B,D,1)
1/16/13	Wind Energy Transmission Texas (TX)	7.15	9.60	40.00	6/12-YE	43.5 (B,D,Z,1)
2/13/13	Indiana Michigan Power (IN)	6.97	10.20	42.67 *	3/11-YE	85.0
2/19/13	Virginia Electric and Power (VA)	8.36	11.40	52.81	3/14-A	4.2 (2)
2/19/13	Virginia Electric and Power (VA)	8.36	11.40	52.81	3/14	48.9 (B,3)
2/22/13	Baltimore Gas and Electric (MD)	7.60	9.75	48.40	9/12-A	80.6
2/27/13	Southwestern Electric Power (LA)	---	10.00	---	12/11	107.0 (B,4)
2/27/13	Empire District Electric (MO)	---	---	---	3/12	27.5 (B)
3/5/13	Mississippi Power (MS)	---	9.70	---	---	156.0 (B,Z,5)
3/12/13	Virginia Electric and Power (VA)	8.36	11.40	52.81	3/14-A	1.7 (B,6)
3/14/13	Niagara Mohawk Power (NY)	6.50 (7)	9.30	48.00	3/14-A	43.4 (D,B,7)
3/19/13	Hawaii Electric Light (HI)	---	---	---	---	--- (B,8)
3/22/13	Virginia Electric and Power (VA)	8.89	12.40	52.81	3/14	5.5 (B,9)
3/27/13	Avista Corp. (ID)	7.91	9.80	50.00	6/12-A	7.8 (B,10)
2013	***1ST QUARTER: AVERAGES/TOTAL***	**7.81**	**10.24**	**49.02**		**765.9**
	OBSERVATIONS	**13**	**15**	**13**		**17**
4/18/13	Northern States Power-Minnesota (SD)	7.78	---	---	12/11-A	11.6 (B)
5/1/13	Duke Energy Ohio (OH)	7.73	9.84	53.30	12/12-DCt	49.0 (D,B)
5/9/13	San Diego Gas & Electric (CA)	---	---	---	12/12-A	115.2 (11)
5/15/13	Consumers Energy (MI)	---	10.30	---	12/13	89.0 (B)
5/30/13	Duke Energy Progress (NC)	7.55	10.20	53.00	3/12-YE	178.7 (B,Z)
5/31/13	Maui Electric (HI)	7.34	9.00	56.86	12/12-A	5.3 (B,I,12)
6/6/13	Southwestern Public Service (TX)	---	---	---	6/12	50.8 (B,I,Z)
6/11/13	Tucson Electric Power (AZ)	7.26	10.00	43.50	12/11-YE	76.2 (B)
6/21/13	Atlantic City Electric (NJ)	8.04	9.75	48.70	9/12-YE	25.5 (D,B)
6/25/13	Puget Sound Energy (WA)	7.77	9.80	48.00	6/12-YE	52.3 (B)
2013	***2ND QUARTER: AVERAGES/TOTAL***	**7.64**	**9.84**	**50.56**		**653.6**
	OBSERVATIONS	**7**	**7**	**6**		**10**
7/12/13	Potomac Electric Power (MD)	7.63	9.36	48.89	12/12-A	27.9 (D)
7/26/13	Madison Gas and Electric (WI)	---	---	---	12/14	0.0 (13)
8/2/13	Virginia Electric and Power (VA)	8.36	11.40	52.81	8/14-A	43.5 (14)
8/8/13	Northern States Power-Minnesota (MN)	7.45	9.83	52.56	12/13-A	102.8 (I)
8/14/13	United Illuminating (CT)	7.21	9.15	50.00	6/12-A	46.1 (D,Z,R)
9/3/13	Delmarva Power & Light (MD)	---	---	---	12/12	15.0 (D,B)
9/11/13	Tampa Electric (FL)	---	10.25	42.00 *(E)	12/14	70.0 (B,Z)
9/11/13	Duke Energy Carolinas (SC)	7.89	10.20	53.00	6/12-YE	118.6 (B,Z)
9/17/13	Black Hills Power (SD)	7.93	---	---	---	8.8 (I,B)
9/18/13	South Carolina Electric & Gas (SC)	8.56	---	53.86	6/13-YE	67.2
9/24/13	Duke Energy Carolinas (NC)	7.88	10.20	53.00	6/12-YE	234.5 (B)

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2/22/13	Baltimore Gas and Electric (MD)	7.53	9.60	48.40	9/12-A	32.4
3/5/13	SourceGas Distribution (WY)	---	---	---	---	0.0 (B,24)
3/13/13	Laclede Gas (MO)	---	---	---	---	4.8 (25)
3/14/13	Niagara Mohawk Power (NY)	6.50 (26)	9.30	48.00	3/14-A	-3.3 (B,26)
3/27/13	Avista Corp. (ID)	7.91	9.80	50.00	6/12-A	4.4 (B,Z)
2013	***1ST QUARTER: AVERAGES/TOTAL***	**7.31**	**9.57**	**48.80**		**38.3**
	OBSERVATIONS	**3**	**3**	**3**		**5**
4/23/13	NorthWestern Corp. (MT)	---	9.80	---	---	11.5 (I,B)
5/1/13	Missouri Gas Energy (MO)	---	---	---	---	1.7 (27)
5/9/13	San Diego Gas & Electric (CA)	---	---	---	12/12-A	8.2 (11)
5/9/13	Southern California Gas (CA)	---	---	---	12/12-A	84.8 (11)
5/10/13	Washington Gas Light (DC)	7.93	9.25	59.30	9/11-A	8.4
5/23/13	Columbia Gas of Pennsylvania (PA)	---	---	---	---	55.3 (B)
6/13/13	Brooklyn Union Gas (NY)	6.98	9.40	48.00	12/13-A	0.0 (B)
6/18/13	North Shore Gas (IL)	6.72	9.28	50.32	12/13-A	6.6
6/18/13	Peoples Gas Light and Coke (IL)	6.67	9.28	50.43	12/13-A	57.2
6/25/13	Puget Sound Energy (WA)	7.77	9.80	48.00	6/12-YE	9.1 (B)
6/26/13	Laclede Gas (MO)	---	---	---	---	14.8 (B,28)
2013	***2ND QUARTER: AVERAGES/TOTAL***	**7.21**	**9.47**	**51.21**		**257.6**
	OBSERVATIONS	**5**	**6**	**5**		**11**
7/26/13	Madison Gas and Electric (WI)	---	---	---	12/14	0.0 (13)
9/23/13	Columbia Gas of Maryland (MD)	7.53	9.60	53.84	3/13-A	3.6
2013	***3RD QUARTER: AVERAGES/TOTAL***	**7.53**	**9.60**	**53.84**		**3.6**
	OBSERVATIONS	**1**	**1**	**1**		**2**
10/16/13	Liberty Energy (Midstates) (MO)	---	---	---	---	0.6
10/22/13	Delmarva Power & Light (DE)	---	---	---	12/12	6.8 (I,B)
11/6/13	Wisconsin Public Service (WI)	8.13	10.20	50.14	12/14-A	-3.9
11/13/13	Duke Energy Ohio (OH)	7.73	9.84	53.30	12/12-DCt	0.0 (B,29)
11/14/13	Michigan Gas Utilities (MI)	6.15	10.25	40.03 *	12/14	4.5 (B)
11/22/13	Washington Gas Light (MD)	7.70	9.50	53.02	3/13-A	8.9
12/5/13	Northern States Power-Wisconsin (WI)	8.34	10.20	52.54	12/14-A	0.0
12/6/13	Consumners Energy (MI)	---	---	---	6/14	--- (30)
12/13/13	Columbia Gas of Kentucky (KY)	---	---	---	12/14	7.7 (B)
12/13/13	Baltimore Gas & Electric (MD)	7.41	9.60	51.05	7/13-A	12.5
12/16/13	Sierra Pacific Power (NV)	6.04	9.70	46.94	12/12-YE	3.9
12/17/13	Piedmont Natural Gas (NC)	7.51	10.00	50.66	2/13-YE	30.7 (B)
12/18/13	Ameren Illinois (IL)	7.75	9.08	51.68	12/14-A	32.5
12/19/13	Peoples TWP (PA)	---	---	---	1/15	13.8 (B)
12/23/13	Public Service Co. of Colorado (CO)	7.53	9.72	56.06	9/12-YE	29.6 (I)
12/30/13	MDU Resources (ND)	7.88	10.00	50.27	12/14-A	4.3 (B,I)

FOOTNOTES (continued)

(17) On 11/22/13, the Commission approved the company's 11/18/13 request to withdraw its rate increase application, and closed the proceeding.

(18) Case involves the recovery of environmental compliance costs through E-RAC Rider.

(19) Case is company's biennial earnings review covering the years 2011 and 2012. The indicated 10% ROE is to be used to calculate under-/over-earnings for 2013 and 2014 and as the base ROE for the calculation of the revenue requirement for the company's various generation riders.

(20) The adopted settlement provides for the company to operate under a formula rate plan that utilizes a benchmark 9.95% ROE.

(21) The adopted settlement provides for the company to operate under a formula rate plan that utilizes a benchmark 9.95% ROE, and for the company to implement a 2013 test year formula rate plan rate increase of $10 million in 12/2014.

(22) Increase authorized under the company's G-RAC rider mechanism that addresses investment in the Dresden Generating Plant and establishes the revenue requirement for the rider that is to become effective 3/1/2014.

(23) The authorized rate increase represents the recovery of a cash return on 2014 incremental CWIP and preliminary true-up of the cash return on 2013 CWIP for Plant Vogtle Units 3 and 4 under the company's legislatively-enabled nuclear construction cost recovery tariff. The authorized rate increase reflects the 10.95% equity return authorized the company for 2014 in a separate base rate case.

(24) In accordance with the approved settlement, the company implemented a $0.3 million one-time rate credit to certain ratepayers in January 2013.

(25) Case represents the company's infrastructure system replacement surcharge rider and reflects incremental investments made from 6/1/12 through 11/30/12, with a pro forma update through 1/31/13.

(26) The Commission approved a $3.3 million gas distribution rate reduction effective 4/1/13, and gas rate increases of $5.9 million and $6.3 million, effective 4/1/14 and 4/1/15, respectively. The rate changes incorporate a 9.3% return on equity (48% of capital) and overall returns of 6.5% (rate year one), 6.65% (rate year two), and 6.85% (rate year three).

(27) Case represents a semi-annual update to the company's infrastructure system replacement surcharge rider and reflects incremental investments made from 6/1/12 through 12/31/12.

(28) The approved settlement provides for no net ratepayer impact, as the entire base rate increase is comprised of amounts being collected through the company's infrastructure system replacement surcharge rider.

(29) PUC adopted a stipulation. Base rates were not changed, but adopted stipulation authorized recovery of $55.5 million of manufactured gas plant remediation costs over five years through a newly established rider. Including roughly $5 million of new revenue that is to be collected through existing riders, the impact of this decision is an estimated overall rate increase of $16.1 million.

(30) Commission approved the company's 11/20/13 filing to withdraw its rate increase request and for the Commission to close the proceeding.

Dennis Sperduto

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY TO ADJUST ELECTRIC RATES	) CASE NO. 91-370

O R D E R

On November 4, 1991, The Union Light, Heat and Power Company ("ULH&P") filed an application with the Commission requesting authority to increase its electric rates for service rendered on and after December 4, 1991. The proposed rates would increase annual electric revenues by $29,702,741, an increase of 20.4 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $22,334,942, an increase of 15.1 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); the Newport Steel Corporation ("Newport Steel"); and joint movants Virginia Anderson, Hazel Buchanan, and Citizens Organized to End Poverty in the Commonwealth ("CO-EPIC").

The Commission suspended the proposed rate increase through May 3, 1992 in order to conduct an investigation into the reasonableness of the proposed rates. A public comment hearing was held at Thomas More College in Crestview Hills, Kentucky, on March 5, 1992, to allow interested parties an opportunity to express their concerns about ULH&P's proposed rate increase. A

PSC – EXHIBIT 2

public hearing was held in the Commission's offices in Frankfort, Kentucky, on March 17-20 and 23, 1992 with all parties of record represented. Simultaneous briefs were filed on April 20, 1992. All information requested during the hearing has been submitted.

On February 10, 1992, ULH&P filed a petition requesting authority to record on its books as a deferred debit the increase in purchased power expense to be incurred as a result of a decision by the Federal Energy Regulatory Commission ("FERC") to allow increased rates for purchased power to become effective subject to refund on February 13, 1992. The increased rates for purchased power were requested by Cincinnati Gas and Electric Company ("CG&E"), the parent and wholesale power supplier of ULH&P. This issue was heard at the commencement of the public hearing on March 17, 1992. On April 17, 1992, the Commission denied ULH&P's request.

COMMENTARY

ULH&P operates as a public utility providing electric and gas service in Boone, Campbell, Grant, Kenton, and Pendleton counties. Within those counties, ULH&P distributes and sells electricity to approximately 106,270 customers.

TEST PERIOD

ULH&P proposed and the Commission has accepted the 12-month period ending July 31, 1991 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

ULH&P proposed a jurisdictional net original cost rate base of $95,645,272.[1] The Commission has made the following modifications to the proposed rate base:

Accumulated Depreciation

In computing its proposed electric jurisdictional net original cost rate base, ULH&P used the test-year end balance for accumulated depreciation. The AG proposed that the test-year end balance should be adjusted to reflect his proposed depreciation adjustment. The AG noted that the Commission routinely adjusts accumulated depreciation by the amount of the depreciation adjustment, and that ULH&P offered no evidence on why this adjustment was inappropriate.[2] ULH&P responded that it never believed this adjustment was appropriate because it improperly values the plant as of the end of the test year, improperly reflects an ongoing level of plant, and represents an arbitrary adjustment which is both inappropriate and inconsistent with the treatment of similar adjustments made to operating results.[3] However, ULH&P presented no evidence to support these allegations.

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1 Schedule B-1 of the Application.

2 DeWard Direct Testimony, page 8.

3 Lonneman Rebuttal Testimony, page 2.

We note that the AG has correctly stated the past practice employed by the Commission. The arguments presented by ULH&P have not persuaded us to reject the AG's adjustment. No authoritative basis has been offered by ULH&P to support a departure from the Commission's long standing practice. Therefore, the Commission will include adjustments to test-year depreciation expense, explained elsewhere in this Order, in the accumulated depreciation used in the determination of rate base. The adjustments increase accumulated depreciation by $14,909.

Prepayments

ULH&P proposed to include $83,041 for the PSC Assessment[4] and $5,236 for auto license taxes as a part of the prepayments component of rate base. ULH&P argues that such expenses, which are applicable to more than a one month period, are considered to be a prepayment. These expenses represent funds which, in ULH&P's opinion, had to be expended prior to their recovery through rates and should be recognized in rate base to compensate ULH&P for this delayed recovery.[5] The AG proposed to remove these two items from the rate base determination, citing the fact that the Commission did so in Case No. 90-041.[6]

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4 Referred to by ULH&P as "KYPSC Maintenance Tax."

5 Response to the Commission's Order dated December 17, 1991, Item 5.

6 DeWard Direct Testimony, page 10.

The Commission is not persuaded by ULH&P's arguments. The classification of the PSC Assessment and auto license taxes as prepayments allows ULH&P to recognize the expense over the entire year, rather than in the month of payment. ULH&P has not performed any lead or lag analysis on these payments. Also, ULH&P has not satisfactorily explained why it should earn a return on taxes it has already paid. As the Commission determined in Case No. 90-041:

> [T]he PSC Assessment and the auto license taxes represent liabilities which are paid for a specific, present time obligation. The rationale employed by ULH&P could be just as easily applied to other of its obligations, such as property taxes and income taxes. . . . These taxes are included in the operating expenses of ULH&P and are recovered from ratepayers through rates. ULH&P would enjoy a double benefit if it were also allowed to earn a return on these taxes.[7]

The Commission has excluded the PSC Assessment and the auto license taxes from the prepayments included in the rate base.

Cash Working Capital Allowance

ULH&P proposed to include in rate base $6,252,870 as a cash working capital allowance. ULH&P determined the allowance using the 45 day or 1/8 formula methodology and then added 10 days of purchased power expense. ULH&P stated that the 10 days represent the number of days it has to finance the purchased power costs before recovery is received from customers. ULH&P arrived at the 10 day figure by combining the number of days after the end of the

[7] Case No. 90-041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, Order dated October 2, 1990, page 10.

month it pays its purchased power bill, with the midpoint number of days for a consumption period. This equals 35 days. This sum was then subtracted from the 45 days used in the traditional formula approach.[8] ULH&P also noted that FERC adjusts for purchased power when it uses the formula approach.[9]

The AG opposed the inclusion of the 10 days of purchased power expense in ULH&P's calculation of cash working capital. The AG argued that inclusion of this one item was inappropriate, and excludes other items which have substantial lead days.[10]

The Commission has traditionally used the 1/8 formula approach in electric utility rate cases and find no basis to now depart from that practice. Concerning the addition of purchased power expense to that calculation, the Commission notes that ULH&P has performed no lead-lag studies for this case.[11] Thus, the use of 10 days is at best an assumption of the time this expense must be financed, not a known period of time. The Commission also notes that FERC will allow an adjustment to the results of the 1/8 formula method when it has been demonstrated that fossil fuel

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8 Bruegge Direct Testimony, pages 5 and 6.

9 Transcript of Evidence ("T.E."), Vol. I, March 17, 1992, page 207.

10 DeWard Direct Testimony, page 7.

11 T.E., Vol. I, March 17, 1992, page 208.

expense is a substantial component of the operation and maintenance expenses and the actual lag in the payment of fossil fuel is known. If an adjustment of fuel expense lag is made by FERC, then a further adjustment will be made to the formula results to recognize the increased importance to the utility of purchased power expense.[12] We cannot adopt ULH&P's proposed modification to the traditional 1/8 formula methodology, even if we chose to follow the stated position of FERC. As ULH&P has noted in its brief, "[t]he Commission has been presented with no evidence which would support departure from past practice."[13] Therefore, we have adjusted the allowance for cash working capital to exclude the 10 days of purchased power expense and to reflect the accepted pro forma adjustments to operation and maintenance expenses, which results in a cash working capital allowance of $2,535,132.

Deferred Income Taxes

ULH&P deducted $13,726,430 in deferred income taxes in the calculation of its rate base. The AG proposed an offset reduction to rate base of $2,256,871, which represents his calculation of the accrued liability associated with uncollectible accounts, post-retirement benefits, and vacation pay. The AG claims that without this adjustment ratepayers will be required to pay for the

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12 Response to AG Hearing Data Request No. 7, Docket No. RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, Termination Order dated October 15, 1990.

13 Brief of ULH&P, page 8.

recorded book expenses as well as a return on the deferred tax charges included in rate base. The AG further claims that his adjustment allows ratepayers some measure of relief from these expenses which are recorded on ULH&P's books but are not funded.[14]

ULH&P opposed the AG proposal, noting that these accounts reflect situations where the book expense occurs before the tax deduction. Because deferred tax accounting has been followed, the ratepayer has benefitted from lower tax expense.[15]

The Commission notes that the AG proposed a similar adjustment in Case No. 90-041, except that he only proposed to eliminate the questioned deferred tax balances, not a corresponding accrued liability. However, the evidence convinces the Commission that the findings adopted in Case No. 90-041 should be readopted here:

> [r]atepayers have benefited from deferred income tax debits since at the time the debits were recorded, book income tax expense was lower than the actual income tax liability. Ratepayers benefit from deferred income tax credits as the tax timing differences which produced the credits reverse.[16]

The Commission will include in the determination of ULH&P's jurisdictional net original cost rate base the test-year end balances of the deferred income taxes, as were included by ULH&P.

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14 DeWard Direct Testimony, page 9.

15 Brief of ULH&P, page 9.

16 Case No. 90-041, Order dated October 2, 1990, page 12.

Based upon the previous findings, the Commission has determined the jurisdictional electric net original cost rate base for ULH&P at July 31, 1991 to be as follows:

Total Utility Plant	$151,975,821
Add:	
Materials and Supplies -	
Distribution	70,214
Other	10,933
Total Materials and Supplies	81,147
Prepayments	144,418
Cash Working Capital Allowance	2,535,132
Subtotal	2,760,697
Deduct:	
Reserve for Accumulated Depreciation	49,093,137
Accumulated Deferred Income Taxes	13,726,430
Investment Tax Credits	96,010
Subtotal	62,915,577
Total Jurisdictional Electric Net Original Cost Rate Base	$ 91,820,941

CAPITAL

ULH&P proposed a total capitalization of $161,152,742.[17] The proposed capitalization included the average daily balance of short-term borrowings for the test year and the total of all investment tax credits as of the test-year end.

The AG proposed a total capitalization of $162,116,790.[18] The difference between the AG's proposal and ULH&P's was that the AG

[17] Mosley Direct Testimony, Exhibit JRM, page 1 of 7.

[18] Weaver Direct Testimony, Exhibit CGK Weaver, Statement 20.

did not include the unamortized premiums and discounts on long-term debt in his total.

At test-year end, ULH&P's total capitalization, before the inclusion of Job Development Investment Tax Credits ("JDIC"), was $161,674,762.[19] In ULH&P's past cases, the Commission has generally allocated capital between electric and gas operations to determine the appropriate capital valuation for each type of utility service. The Commission believes that the use of this method is appropriate for rate-making purposes and has determined ULH&P's jurisdictional capital devoted to electric operations to be 52.771 percent of total capitalization based on the ratio of electric operations rate base to total company rate base as determined in Appendix B. The resulting capital assigned to jurisdictional electric operations is $85,316,929.

The Commission has increased this $85,316,929 by $3,706,088,[20] which is the jurisdictional amount of JDIC applicable to electric operations. The JDIC has been allocated to each component of capital based on the ratio of each capital component to total capital excluding JDIC. Both ULH&P and the AG included all investment tax credits as JDIC, without removing the investment tax credits included in the determination of rate base

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19 Schedule A-3.9 of the Application and the Response to the Commission's Order dated November 14, 1991, Item 1, page 4 of 8.

20 Schedule B-6 of the Application, lines 3 and 4.

from the total or excluding the non-jurisdictional portion of the investment tax credits. ULH&P and the AG did not allocate the amounts to the components of capital. The Commission has traditionally followed the practice of allocating JDIC to the capital components. This treatment is entirely consistent with the requirements of the Internal Revenue Service that JDIC receive the same overall return allowed on the components of capitalization.

REVENUE AND EXPENSES

For the test period, ULH&P had actual electric jurisdictional net operating income of $8,982,177. ULH&P proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted jurisdictional net operating income of a negative $6,857,458.[21] The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications:

Weather Normalization

ULH&P proposed an adjustment to reduce revenues by $1,526,929 to reflect the test year's deviation from normal temperatures as measured in cooling degree days and heating degree days. ULH&P determined its normal temperatures and normal degree days based on the 30-year average data published by the National Oceanic and Atmospheric Administration ("NOAA") for the period from 1951 through 1980.

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21 Schedule C-2 of the Application.

The AG recommended that the Commission reject the proposed adjustment claiming, among other things, that (1) the methodology used by ULH&P to calculate the adjustment was questionable; (2) ULH&P's model does not separately identify temperature-sensitive load and non-temperature-sensitive load; (3) the proposal does not take into consideration the affects of weather on CG&E's allocation of costs to ULH&P; (4) the 30-year data for the period ended 1980 does not reflect the impact of the warming trend of the past decade; and (5) ULH&P's choice of a test year ended July 31, 1991 greatly impacts the magnitude of the adjustment.

ULH&P took issue with the AG's claims and defended its adjustment as one that produces reasonable results for rate-making purposes. ULH&P claimed that its methodology was appropriate and fully documented, and that separating loads into temperature-sensitive and non-temperature- sensitive components would introduce additional error into the weather normalization process. ULH&P stated that CG&E's cost allocation was based on a future test year that included normal temperatures and ULH&P opined that neither it nor this Commission should rely on any temperature normals other than the 30-year data published by NOAA. Finally, ULH&P argued that its choice of test year was not related to its proposed weather normalization adjustment but, if that were the case, it might have chosen the 12 months ended May 31, 1991, as suggested by the AG.

The Commission has a number of concerns. We are not persuaded that ULH&P's methodology is acceptable for rate-making purposes nor are we persuaded that it is appropriate for an electric utility to attempt to normalize for weather while ignoring the other factors that affect energy usage. ULH&P contends that altering its method to separate loads into temperature-sensitive and non-temperature-sensitive components would introduce additional error into the normalization process; however, it did not support this contention nor did it consider whether such a separation might improve its determination of the level of weather normalized sales. ULH&P used its load forecasting model to derive its weather normalization adjustment and held all variables within the model, other than the weather variable, constant, or at actual test-year levels. This approach does not consider, or attempt to normalize, these other variables which is in direct opposition to a prior Commission opinion on this subject.[22]

The Commission has reviewed the applicable publications referenced by ULH&P concerning official weather normals as established by NOAA. Our review indicates that the 1951-1980 data is the most current official 30-year data available, as ULH&P claims. Our review also indicates that NOAA makes available sufficient information to enable someone to replicate that data or perform a comparable calculation for a different period of time. As indicated in other cases, the Commission considers it important

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[22] Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

that weather data be current.[23] ULH&P's normalization adjustment does not recognize the impact that temperatures in recent years might have on determining normal temperatures.

The Commission is also concerned about the accuracy of ULH&P's approach to calculating billing-degree days for its 21 billing cycles. In its calculation, ULH&P gives equal weight to each of the 21 billing cycles even though (1) the number of days in each billing cycle can vary from month to month and (2) the number of customers per class for each billing cycle is not available for comparison. This approach may not properly match customers' loads and their corresponding bills since each billing cycle has different beginning and ending dates with a specific number of degree days and a specific number of customers for each month of the year. Although ULH&P indicated other utilities had researched this matter and found the potential for greater accuracy from use of a more detailed weighting approach was not statistically significant, ULH&P had not made a similar independent determination. Absent such a determination, we are not persuaded that the equal weighting approach used by ULH&P is sufficiently accurate for use in the rate-making process.

ULH&P's proposed weather normalization adjustment is denied. This results in an increase of $1,526,929 to ULH&P's normalized revenues, and will impact ULH&P's adjusted purchased power cost, <u>supra</u>.

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23 <u>Id.</u>

Interruptible Credit - Newport Steel

As part of its revenue normalization calculation, ULH&P adjusted its revenues to reflect a full 12 months at the rates in effect at test-year end. One component of ULH&P's adjustment was the annualization of the interruptible credit to Newport Steel based on the terms of the 1991 service agreement between ULH&P and Newport Steel and the level of firm, curtailable, and interruptible demands designated by Newport Steel for the last month of the test year. The annualization of Newport Steel's interruptible credit reduces ULH&P's revenues by $1,521,275.

The AG made two proposals concerning the Newport Steel interruptible credit. The first proposal, that ULH&P's annualization adjustment be disallowed, is based on the AG's concerns about the terms of the service agreement, the lack of any showing that the interruptible nature of the Newport Steel portion of ULH&P's load is properly reflected in CG&E's allocation of costs to ULH&P, and questions of whether the test year includes a representative, forward-looking level of sales to Newport Steel consistent with the terms and conditions of the agreement. The AG's second proposal is that the Commission disallow any interruptible credits in ULH&P's rates since ULH&P is not a generator of electricity. The AG suggests that all contracts for interruptible power should be between CG&E (the generator) and the interruptible customer. In arguing for this proposal, the AG contends that the amount of the monthly credit, $4.45 per KW at present and $5.25 per KW proposed, is excessive and is not based on the avoided cost of new generating capacity for CG&E, which supplies 100 percent of ULH&P's power requirements.

ULH&P and Newport Steel argued against the AG's proposals claiming that their service agreement was beneficial to ULH&P's ratepayers. Newport Steel, after calculating an avoided cost for CG&E of $7 per KW per month, opines that both the current and proposed credits are justified and that the difference between the credit and CG&E's avoided cost represents a savings, or benefit, to ULH&P's remaining customers. Newport Steel also opposed the AG's suggestion that CG&E contract directly with ULH&P's interruptible customers, maintaining that such an arrangement would unduly complicate the regulatory process by potentially involving three jurisdictions, Kentucky, Ohio, and the FERC, in the review of such contracts. Newport Steel did share the AG's concerns that CG&E's proposed allocation of costs to ULH&P at the wholesale level does not fully recognize the nature of Newport Steel's interruptible load. Newport Steel indicated that this problem could be remedied at the FERC level if the Commission was not able to address it in this proceeding and suggested the type of modification that CG&E could make to its cost allocation study.

The Commission is not persuaded that the amount of the credit is excessive, nor do we find that there has been established any link between the amount of the credit and CG&E's avoided cost of new capacity. The Commission will not revoke the agreement or direct ULH&P to forego entering into such agreements in the future. The agreement, as executed, was approved by Commission Order dated April 4, 1991,[24] after an earlier version of the agreement had been rejected on September 27, 1990.[25] Such agreements, properly reflected in the rate-making process, can be of long-term benefit to ULH&P, Newport Steel, and ULH&P's other customers as well. In this instance, however, the Commission has two concerns as to whether this agreement has been properly reflected in the rate-making process.

The Commission's first concern is that the allocation of costs to ULH&P by CG&E does not properly reflect the interruptible nature of Newport Steel's load. The record reflects that CG&E's pending FERC application, based on a coincident peak cost allocation methodology, does not take into account the fact that Newport Steel can be interrupted other than at the time of CG&E's coincident peak. In approving the agreement, the Commission presumed that all aspects of Newport Steel's interruptible load would flow through to CG&E since it is CG&E, not ULH&P, which controls the capacity and determines when loads will be interrupted. Since the entire CG&E system benefits from the interruptible nature of Newport Steel's load, ULH&P's customers, representing only 15 percent of the system, should not bear the

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24 Case No. 91-076, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

25 Case No. 90-068, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

brunt of the agreement's cost in the form of lower revenues through increased demand credits.

Our second concern deals with the demand level for Newport Steel included in the test year. Newport Steel's average monthly demand during the test year was 55,000 KW. In Case No. 90-068, ULH&P indicated that, with the operation of a third furnace, Newport Steel's monthly demand was expected to increase by one-half to approximately 80,000 to 85,000 KW with a corresponding increase in demand charge revenues.[26] ULH&P also indicated that, even with the larger demand credits under the new agreement, its annual revenues from Newport Steel would increase to $10.5 to $12 million compared to $9 to $9.5 million without the new agreement.[27] ULH&P's test-year revenues from Newport Steel, based on the test-year average demand, were $9.3 million.[28] However, ULH&P failed to propose any adjustment to reflect the anticipated increases in demand and revenues from Newport Steel.

It is apparent that ULH&P's adjustment to increase Newport Steel's interruptible demand credit only recognizes one aspect of their new service agreement. It is also apparent that ULH&P's purchased power cost does not equitably reflect the interruptible

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26 Response filed June 9, 1990 to the Commission's Information Request - First Set, Item 16.

27 Id.

28 The Union Light, Heat and Power Supplement C(9), WPC-3.1e.

nature of Newport Steel's load. For these reasons, the Commission has adopted the AG's recommendation to disallow ULH&P's proposed adjustment to annualize Newport Steel's interruptible credits. Such a disallowance increases ULH&P's normalized base revenues by $1,521,275 which, in turn, produces an increase of $9,843 in ULH&P's normalized forfeited discount revenue.

Fuel Synchronization

ULH&P initially proposed an adjustment to reduce fuel ("FAC") revenues by $200,996 in an attempt to match, or synchronize, FAC revenues with FAC expense. ULH&P modified its adjustment to produce a revenue reduction of $41,332. Both adjustments reflect the 2-month billing lag built into the FAC.

The AG recommended that ULH&P's proposal to reduce FAC revenues be rejected and proposed to increase such revenues by $244,578 over the actual test-year level. The AG argued that the adjustment should be based on test-year revenue levels rather than revenues for a period 2 months beyond the test year.

The Commission will accept the AG's proposal. The AG's adjustment is consistent with the approach used by the Commission in ULH&P's last case and in numerous other cases. While there is a 2-month billing lag inherent in the FAC mechanism, ULH&P's revenue requirements are being determined based on a 12-month test period ended July 31, 1991. ULH&P's approach doesn't consider the FAC revenues for the test period, but rather, the revenues for the 12 months ended September 30, 1991, 2 months beyond the test period. The purpose of the AG's adjustment is to eliminate any over- or under-recovery of fuel costs within the test year from the determination of revenue requirements. To achieve this purpose, the adjustment must be based on the fuel costs and fuel revenues reported during the test period upon which revenue requirements are being determined. This adjustment results in a $445,574 increase to ULH&P's normalized revenues.

Year-End Customer Adjustment

ULH&P proposed adjustments to increase revenues and purchased power costs by $283,687 and $244,063, respectively, based on the difference between the average number of customers served during the test year and the number of customers served as of the end of the test year. The increased KWH sales and increased KWH purchases included in the calculations reflected the impact of ULH&P's proposed weather normalization adjustment. The average cost per KWH as calculated by ULH&P reflected the projected increase in purchased power costs from CG&E.

Based on its proposal that ULH&P not be allowed to recover its increased purchased power costs, the AG argued that such costs should not be included in the calculation of the year-end customer adjustment. Based on this argument, the AG reduced ULH&P's year-end customer purchased power adjustment by $44,985.

The Commission has modified ULH&P's year-end customer adjustment to eliminate the impact of the proposed weather normalization adjustment from the calculations, consistent with our decision to reject the weather normalization adjustment. Based on actual test-year KWH sales and purchases, the increases to revenues and purchased power costs have been calculated to be $756,203 and $624,579, respectively.

Purchased Power Expense

ULH&P proposed an adjustment to increase its purchased power expense by $25,031,563. This adjustment reflected a proposed increase in CG&E's wholesale power rate, a reduction to ULH&P's purchased power volumes based on its proposed weather normalization adjustment and correction of a billing error in the last month of the test year. The increased wholesale power rate was allowed to go into effect February 13, 1992, subject to refund, pending final resolution of CG&E's rate case before the FERC.

The AG contends that the wholesale power contract between CG&E and ULH&P should be examined to determine whether ULH&P should have sought out other power suppliers. The AG argues that, while this Commission cannot rule on the reasonableness of CG&E's rate to ULH&P, it could find ULH&P's purchase from CG&E to be imprudent due to the existence of lower cost alternative power supplies. In support of this argument the AG cites a number of recent contracts for purchased power at rates less than those charged by CG&E. The AG goes on to argue that, as the contract between CG&E and ULH&P is a less-than-arm's length agreement and since ULH&P did not solicit bids from other suppliers, its purchase from CG&E is imprudent. The AG recommends that the Commission require ULH&P to solicit bids for other power supplies to ensure that customers' best interests are being served.

In addition to its bidding proposal, the AG opines that the Commission must deny ULH&P's requested adjustment on the grounds that it is not known and measurable. The argument goes that since the increased rate from CG&E is subject to refund pending the

FERC's final decision, the current rate is not permanent and will likely not be the final rate approved by FERC. The AG also questions whether this Commission can require ULH&P to make refunds to its customers of amounts refunded to ULH&P by CG&E in the event the FERC requires such refunds by CG&E.

ULH&P defended its decision to contract with CG&E for 100 percent of its power requirements. ULH&P opines that firm power, in the amount and quality required to meet its customers' needs, is not available in the region at a price less than the CG&E rate. ULH&P contends that power from other, further-away sources, while priced at rates comparable with CG&E, would incur wheeling charges that render it uneconomical.

ULH&P also claims that the AG's argument does not recognize all the additional costs ULH&P would incur to secure power from sources other than CG&E. Chief among these costs would be a capital investment of over $100 million for bulk power transmission facilities necessary for its own connections with other utilities. ULH&P also maintains that, under its contract with CG&E, it pays only for its monthly metered demand without incurring a minimum demand charge which it would incur if it were required to purchase power from another source.

ULH&P states that there is no reason for concern as to the protection of its customers in the event the FERC's final decision in the pending CG&E case produces a rate less than that allowed to go into effect February 13, 1992. ULH&P contends that any refund it receives from CG&E will, in turn, be refunded to its customers.

As the Commission stated in its December 13, 1991 Order, the FERC has exclusive jurisdiction to review and determine a reasonable rate for the sale of power to ULH&P. CG&E's request to increase the rate paid by ULH&P is intended solely to recover the substantial sums expended to convert the Zimmer Generating Plant ("Zimmer") from a nuclear to a coal-powered facility. Based upon our knowledge of the cost of Zimmer and the costs of comparable coal-powered generating plants, it is clear that the cost of Zimmer is excessive by at least 50 percent. Due to our lack of jurisdiction over CG&E's cost of Zimmer and the determination of a reasonable rate for power sales to ULH&P, we have intervened at the FERC and will vigorously oppose CG&E's attempts to recover unreasonable Zimmer costs from ULH&P.

The Commission is legally bound to accept as reasonable the purchased power rate as filed with the FERC and that filed rate must be recognized as a legitimate expense for retail rate-making purposes.[29] However, the courts have recognized a limited exception to this rule in situations where the affected utilities are not members of a regulated holding company. The exception allows a state commission to recognize in retail rates an amount less than the FERC filed rate if lower cost alternative power is available elsewhere.

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29 Mississippi Power and Light Co. v. Mississippi, ex rel. Moore, 487 U.S. 354 (1988).

In this case, the Commission can make no finding that lower cost alternative power is actually available. Even though we believe the cost of Zimmer to be excessive, the FERC filed rate is a composite rate which reflects the costs of all of CG&E's generating units, not just Zimmer. While the AG has alleged the existence of lower cost supplies, ULH&P has effectively refuted the allegations. The record shows the potential supplies identified by the AG to be either inferior in quality, i.e. less than firm power, or higher in price than the power ULH&P obtains from CG&E. Since ULH&P owns no generating facilities of its own, any power purchases must be of firm power which is available 24 hours per day, year round, in the contracted for quantities. The record is devoid of any credible evidence that a lower cost alternative supply is actually available. Absent this evidence, the Commission can make no finding that the FERC filed rate is unreasonably excessive in light of alternative power supplies.

The AG's contention that ULH&P's adjustment to increase purchased power expense is not known and measurable is unfounded. The rate ULH&P is being charged by CG&E has been accepted by, and is on file with, the FERC. This FERC filed rate is both known and measurable albeit potentially temporary in nature. As an intervenor in CG&E's pending case before the FERC, the Commission will be well aware of both the timing and magnitude of any reduction in CG&E's filed rate and will take the steps necessary to ensure that ULH&P's customers receive any refunds due them. The rates granted herein will be subject to refund pending a final decision by the FERC on CG&E's wholesale power rate.

The increase proposed by ULH&P has been modified to eliminate the impact of its proposed weather normalization adjustment. The modified increase, on a Kentucky jurisdictional basis, is $25,598,523.

Labor and Labor-Related Costs

ULH&P proposed adjustments to increase the test-year operating expenses by $233,378 for labor and labor-related costs. The actual cost items and the proposed adjustments to electric operations are as follows:

	Total
Wages and Salaries	$ 227,411
SIP & DCIP Plan Costs	3,184
FICA Taxes	2,783
	$ 233,378

Wages and Salaries. ULH&P proposed to increase wages and salaries by $227,411, to reflect the annualization of base wage increases granted to all employee groups during the test year. ULH&P calculated the adjustment by multiplying the average hourly wage increase by the number of hours charged to the electric operations, and then annualizing the result by the appropriate number of months.

ULH&P provided a series of workpapers which documented the hours worked during the test year by ULH&P employees for ULH&P activities.[30] The labor hour allocation process used by ULH&P and

30 Application Workpapers WPC-3.4d through WPC-3.4o, also summarized as Staff Cross-Examination Exhibit No. 1 - Bruegge.

CG&E also includes the determination of hours worked by CG&E or other subsidiary employees for ULH&P activities and the hours worked by ULH&P employees for CG&E or other subsidiary activities. Documentation of these hours was not provided by ULH&P.

ULH&P provided a workpaper showing the allocation of hours worked by bargaining groups and account distribution for the month of May 1991. ULH&P bases its annual allocation of labor hours on the distributions developed from May data. This allocation process assigns hours to gas or electric operations, construction work in progress, retirement work in progress, work performed by other CG&E employees for ULH&P (referenced as accounts payable), and work performed by ULH&P employees for CG&E (accounts receivable).[31] While ULH&P has based its annual allocation on the activity in the month of May for many years, there has not been any verification undertaken by ULH&P to determine that May is the most representative month to use.[32]

The allocation percentages used in the May labor analysis are based on annual time studies. The time studies related to unionized labor groups usually are documented by work orders. The time studies for supervisory, administrative, and professional employees are based upon an annual study performed in October.

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[31] Application Workpaper WPC-3.4b.

[32] T.E., Vol. II, March 18, 1992, pages 44 and 45.

The hours reported in the study for this group are not based on the actual work performed in that month, but rather reflect what ULH&P purports to be a more "representative" or "normal" month.[33]

In reviewing the evidence provided by ULH&P concerning its labor hour allocation process, the Commission is concerned about several issues. First, the only allocation which should be needed for the hours worked by ULH&P employees for ULH&P activities would be between gas or electric operations, construction work in progress, and retirement work in progress. However, in determining the hours used in the wage normalization, the test-year actual hours worked by ULH&P for ULH&P were also allocated to the accounts payable and accounts receivable categories.

In reviewing the May labor hour allocations, the hours shown on that workpaper could not be matched or reconciled with the hours represented to be the actual hours worked by ULH&P for ULH&P for the month of May 1991. In the 1989 Management and Operations Review of ULH&P, the management auditors expressed concern about the time documentation process used in the supervisory, administrative, and professional group's time studies and recommended alternative methods be reviewed to develop more reliable means of gathering time data.[34] Furthermore, the Uniform

33 T.E., Vol. III, March 19, 1992, page 254; T.E., Vol. II, March 18, 1992, pages 44 and 45.

34 Management and Operations Review of The Union Light, Heat and Power Company, August 1989, pages 54 and 60.

System of Accounts for Electric and Gas Utilities ("USoA") requires that the distribution of employee wages "[s]hall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period."[35]

The Commission is not opposed to the concept of wage normalization. However, the problems we have noted concerning labor hour documentation and allocation make it impossible to verify the reasonableness of the proposed wage normalization adjustment. Therefore, the Commission must reject the $227,411 adjustment proposed by ULH&P. As recommended by the management auditors, the Commission instructs ULH&P to conduct a thorough review of its labor hour allocation and documentation processes and bring it into conformity with the requirements outlined in the USoA. This will require ULH&P to change the supervisory, administrative, and professional group's time study to one which is based on actual time worked. It will further require that ULH&P determine what is a representative period, which may include more than one month of a year.

<u>Savings Incentive Plan ("SIP") and Deferred Compensation and Investment Plan ("DCIP").</u> ULH&P proposed an increase of $3,184 for its SIP and DCIP. Executive, supervisory, administrative, and professional employees can participate in DCIP, while all other employees of ULH&P can participate in SIP. ULH&P determined the

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35 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 4.

increase by applying a cost factor to its proposed wage normalization adjustment. ULH&P stated that as wages increase, its contributions to the SIP and DCIP would also increase.[36] The AG opposed the inclusion of any costs associated with the DCIP, citing the current state of the economy and the size of ULH&P's proposed rate increase.[37]

The Commission is not persuaded to remove all costs of the DCIP. These types of fringe benefits are commonly provided by major utilities and there is no valid reason why such benefits should be denied to one class of ULH&P's employees and allowed for another. We have determined that ULH&P's contributions to the plans are a function of three independent factors: the number of employees enrolled in the plans; the amounts contributed by participating employees; and ULH&P's required matching contribution rate, which is limited to the first 5 percent of the participating employee's base pay.[38] Given these factors, it is inappropriate to calculate an increase for these contributions by simply applying a cost factor to the proposed wage normalization. Based on this finding, and the above finding to reject the

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36 Response to the Commission's Order dated December 17, 1991, Item 31.

37 DeWard Direct Testimony, pages 22 and 23.

38 Response to the Commission's Order dated November 14, 1991, Items 45(a) and 45(p).

proposed wage normalization adjustment, the Commission has not included the proposed increase in the costs of the SIP and DCIP.

FICA Taxes. ULH&P proposed to increase its FICA taxes by $2,783. The increase reflected changes in the FICA applicable base wage and tax rates which became effective January 1, 1991. The proposed adjustment was calculated on the 1990 calendar year wages and did not reflect the impact of wage increases granted between January 1991 and the test-year end.

In Case No. 90-041, the Commission expressed concern about ULH&P's presentation of wage adjustments and payroll tax adjustments based on different time periods. Using different time periods for these types of adjustments is inherently unreliable and inaccurate. ULH&P was instructed that, in future cases, adjustments to wages and salaries and payroll taxes should reflect the same time periods.[39] Despite this instruction, ULH&P has again presented these adjustments based on different time periods. Due to the improper calculation of the proposed adjustment to FICA taxes, the adjustment must be rejected.

Key Employee Annual Incentive Plan ("KEAIP"). The AG proposed to remove all test-year costs associated with the KEAIP. The AG included this proposal with this recommendation to remove all costs related to the DCIP. The amount the AG proposed to exclude contained test-year costs for both electric and gas operations.

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39 Case No. 90-041, Order dated October 2, 1990, page 31.

Based on a thorough review of the KEAIP provisions, the Commission will exclude these expenses for the following reasons. First, while the plan does include so-called protection clauses for both customers and shareholders, the plan narrative clearly states that, "The Board, the Compensation Committee, and management all agree that the interests of shareholders must be paramount and protected when considering the appropriateness of any compensation program for key employees."[40] The Commission believes that, for a utility, the interests of the shareholders and the customers should be balanced and protected.

Second, in reviewing the performance objectives for calendar years 1990 and 1991, the 1991 performance objective targets were reduced only in those areas where in 1990 ULH&P and CG&E key employees had failed to reach the target.[41] ULH&P explained that some of these reduced targets were related to the fact that ULH&P and CG&E were going to be involved in rate cases during 1991.[42] However, in 1990 ULH&P was involved in a rate proceeding and it would not seem reasonable that pending cases in 1991 would be the sole reason to reduce performance objective targets. Finally, the Commission has carefully examined the evidence concerning the

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40 Response to the Commission's Order dated December 17, 1991, Item 60, page 2 of 4.

41 Response to the Commission's Order dated January 17, 1992, Item 43(d) and 43(e).

42 T.E., Vol. III, March 19, 1992, pages 216 and 217.

compensation and benefits available to these key employees. It appears that key employees received salary increases in addition to KEAIP payments[43] and that the overall benefits package, exclusive of the KEAIP payments, is quite adequate.[44]

The test-year expenses for KEAIP should not be included for rate-making purposes and electric operating expenses are reduced by $26,201.

Executive Severance Agreements. Included with the AG's proposal to remove the test-year expenses for DCIP and KEAIP was the removal of $166 of test-year expenses for executive severance agreements. The Commission has searched the record and is unable to find any evidence that the ratepayers were charged for executive severance agreements. We do note, however, that the expenses for the supplemental executive retirement plan were not included in this electric rate case.[45] Due to the minuscule amount of this proposed adjustment and the absence of verification that it was included in the test year, no adjustment to operating expenses will be made.

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43 Response to the Commission's Order dated November 14, 1991, Item 37.

44 Response to the Commission's Order dated December 17, 1991, Item 58.

45 Response to the AG's Supplemental Data Request, Item 44.

Meter Reading Workforce Reduction. The 1989 Management Audit Report included a recommendation that ULH&P undertake a re-routing of its meter reading routes. Although the work on this recommendation is still in progress, ULH&P indicated that it had already realized a reduction in the meter reading workforce of four employees, resulting in an annual wage savings of $125,000.[46] ULH&P proposed no adjustment to the test-year operations to reflect this savings.

It is appropriate to reflect these savings and accordingly test-year operating expenses have been reduced by $125,000.

Overtime Labor. In Case No. 90-041, the Commission expressed its concern over the increased levels of overtime hours incurred by ULH&P. In this case, ULH&P included a schedule showing the test-year actual and five previous calendar years' level of overtime hours.[47] This schedule shows that, with the exception of 1989, the level of overtime hours has been steadily increasing. ULH&P was asked to describe the steps taken by it and CG&E to control the level of overtime hours. However, ULH&P only responded that it had taken steps to utilize employees to the maximum effort possible, and provided no specific actions taken.[48]

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46 Response to the Commission's Order, dated January 17, 1992, Item 66(c).

47 Schedule C-11.1 of the Application.

48 T.E., Vol. III, March 19, 1992, page 237.

ULH&P has failed to recognize the ever increasing level of expense associated with overtime. No study or analysis has been performed to determine an optimal level of overtime or an optimal workforce level. Therefore, the Commission will reduce the overtime labor expense to reflect the historic average of overtime labor hours. We believe this approach results in a more reasonable level of expense under the circumstances in this case and have reduced operating expenses $74,287, as determined in Appendix C.

The Commission is also concerned by ULH&P's allocation of overtime labor hours. The overtime labor hours are converted to equivalent regular labor hours and allocated to the same accounts as the regular hours, regardless of the source of the overtime hours. ULH&P has performed no analysis to support the assumption that overtime labor hours should be allocated on the same basis as the regular labor hours. There is no evidence to demonstrate that ULH&P's current practice results in a reasonable allocation. The Commission will require ULH&P to modify its overtime labor hour allocation procedures in order that overtime will be allocated to the source of that overtime.

Labor Study. In Case No. 90-041, the Commission instructed ULH&P to provide a thorough analysis of its staffing levels with its next general rate case.[49] ULH&P did not provide or perform such an analysis. ULH&P indicated that it had not planned to file this

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[49] Case No. 90-041, Order dated October 2, 1990, page 34.

rate case and that it was not prepared to comply with the Commission's instructions.[50] In the 1989 Management Audit Report, several labor-related areas were identified as needing the attention of ULH&P.

The Commission is concerned about the numerous labor-related issues which have come to our attention during this proceeding. We believe the record clearly indicates that ULH&P must affirmatively address issues concerning its labor needs as part of the integrated CG&E system, the management of overtime hours, the reasonableness of current assumptions concerning spans-of-control, and all other management audit recommendations focusing on labor-related issues. The Commission expects that by the next general rate case, ULH&P will have taken appropriate constructive action on all of these issues. The Commission will evaluate the prudency of all ULH&P responses regarding labor and labor-related costs.

Uncollectible Accounts

As in past cases, ULH&P included in its requested revenue increase a commensurate increase in its provision for uncollectible accounts based upon its test-year provision for uncollectibles viewed as a percentage of total revenues. ULH&P used a test-year provision for uncollectibles, as a percentage of

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50 T.E., Vol. IV, March 20, 1992, page 71.

total revenues, of 1 percent.[51] However, this percentage reflected the blended provision for both gas and electric operations. The test-year electric provision for uncollectibles was .95 percent.[52] The Commission accepts ULH&P's methodology of adjusting uncollectible accounts, but will apply the test-year electric provision percentage rate to the revenues as adjusted in this Order. The Commission will determine ULH&P's revenue requirement using .95 percent to reflect the increase in uncollectible accounts expense associated with the revenue increase granted herein.

PSC Assessment

ULH&P included in its requested revenue increase a commensurate increase in the expense for the PSC Assessment, based upon the assessment rate in effect during the test year. The Commission accepts this proposal and has normalized the assessment based on the normalized revenues as adjusted in this Order. The Commission will include the PSC Assessment rate in the determination of ULH&P's revenue requirement.

Charitable Contributions

As it has in its three previous cases, ULH&P proposed an adjustment to increase operating expenses by $88,576 to reflect the expense for charitable contributions made during the test

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51 Application Workpaper WPC-12a.

52 Response to the Commission's Order dated December 17, 1991, Item 46.

year. While ULH&P acknowledged that the Commission has not recognized this adjustment in past decisions, ULH&P stressed that this is a necessary business expense which is a response to the needs and desires of the community.[53] However, ULH&P presented no new evidence, not previously considered by the Commission, to support this adjustment. The AG opposed the proposed adjustment, citing past Commission practice to deny such expenses.

The Commission has consistently excluded donations for rate-making purposes because the expense is not related to the provision of utility service. Donations enhance a utility's corporate image and are properly borne by the shareholders. ULH&P has failed to persuade us to include the expense in this case.

Rate Case Expenses

ULH&P proposed to adjust operating expenses by $50,000 to reflect its estimate of the entire cost of this rate case. Although no expenses related to this case were included in the test year, $17,968[54] related to Case No. 90-041 was included in the test year.

Throughout this proceeding, the Commission required ULH&P to provide the current actual rate case cost, with adequate supporting documentation. ULH&P was opposed to an ongoing filing

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53 Bruegge Direct Testimony, page 9.

54 Schedule C-10 of the Application.

but agreed to file its last updated actual rate case cost 20 calendar days after the completion of the public hearing.[55] The public hearing was completed on March 23, 1992, making the last update due April 12, 1992. ULH&P filed its last update with the Commission on April 22, 1992. The last update contained costs which were inadequately documented. Therefore, the Commission has rejected the April 22, 1992 filing and will use the cost information from the March 4, 1992 response as the basis for its adjustment. The actual rate case costs filed on March 4, 1992 totaled $35,742.

It would not be reasonable for ULH&P to recover the costs of this rate case every year that the rates established herein are in effect. It also would not be reasonable to use an estimated cost when the actual cost is known. The Commission believes it is appropriate in this case to amortize $35,742 in actual costs over a 3-year period, or an annual amortization of $11,914. The test-year expenses for Case No. 90-041 should be removed from operating expenses, resulting in a net reduction in operating expenses of $6,054.

Amortization of Management Audit Cost

ULH&P proposed to increase operating expenses $51,385 to reflect the annual amortization of its management audit costs. In

[55] Response to the Commission's Order dated January 17, 1992, Item 46.

Case No. 90-041, the Commission approved ULH&P's proposal to amortize $257,067[56] in management audit costs over a 3-year period. At the end of the suspension period in this case, 17 months or $121,407[57] would remain to be amortized. At the present amortization rate, ULH&P would recover the cost by October 1993.

ULH&P is entitled under the management audit statute to recover the total cost of the management audit but it is not entitled to recover in excess of its cost. Thus, to avoid over-recovery, the amortization rate should be adjusted. The annual amortization rate for rate-making purposes should be $40,464 based on a 3-year amortization of the unamortized cost through the end of the suspension period. The electric portion of the revised amortization is 60 percent, or $24,278. Therefore, the Commission has increased operating expenses by $24,278.

Depreciation Expense

ULH&P proposed to increase depreciation expenses by $218,909. The adjustment reflected the normalization of depreciation expense on utility plant in service at test-year end. The AG proposed to reduce the normalized expense by $204,000 to reflect the over-depreciation of overhead street lighting plant.[58] The

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56 Case No. 90-041 Application Workpapers WPC-3.6a.

57 $257,067 multiplied by (17 months / 36 months).

58 DeWard Direct Testimony, page 31.

Commission has reviewed the utility plant information and has determined that the overhead street lighting account was fully depreciated at test-year end.[59] ULH&P has stated that it would stop depreciating the account at the time the net plant is zero.[60]

The Commission has included only $14,909 of the depreciation expense adjustment proposed by ULH&P. This adjustment has been included in the accumulated depreciation used to determine the jurisdictional electric net original cost rate base. This has been the Commission's traditional practice concerning depreciation expense adjustments.

Interest Synchronization

ULH&P proposed to adjust its interest expenses used in computing state and federal income taxes. ULH&P's approach was to apply the weighted cost of long-term debt to its rate base. The test-year actual interest expense was deducted from this amount to arrive at the adjustment to interest expense for the computation of income taxes.

Historically, for rate-making purposes, the Commission has imputed interest expense on the portion of JDIC assigned to the debt components of the capital structure and treated the interest as a deduction in computing the income tax expense allowed in the cost of service. The revenue requirements in this proceeding are

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59 Schedule B-3 of the Application, page 2 of 4.

60 T.E., Vol. I, March 17, 1992, page 176.

being determined from the capitalization rather than the rate base; therefore, the Commission believes its previous practice is more appropriate in determining the interest synchronization. This was the same approach used by the Commission in previous ULH&P general rate cases. The Commission has applied the applicable cost rates to the JDIC allocated to the debt components of the capital structure. ULH&P's interest expense applicable to Kentucky jurisdictional operations during the test year was $4,465,702. Using the adjusted capital structure allowed, the Commission has computed an interest expense reduction of $172,469, which results in an increase to income tax expense of $68,029.

Storm Damages

ULH&P proposed an adjustment of $6,934 to increase its expenses for storm damages to reflect the 10-year average expense. The adjustment was calculated using the June 1991 Consumer Price Index-Urban ("CPI-U") to adjust the recorded dollar amount to July 31, 1991. Such an adjustment is consistent with the Commission's decisions in previous ULH&P rate cases; however, the Commission believes that it is more appropriate to use the July 1991 test-year end CPI-U. The Commission has recalculated the adjustment using the appropriate CPI-U for the test year and has determined that operating expenses should be increased $7,075.

Injuries and Damages

ULH&P proposed an increase of $57,080 to its expenses for injuries and damages to reflect the 10-year average expense. The adjustment was calculated using the same methodology as had been used in the adjustment for storm damages. Because the Commission believes it is more appropriate to use the test-year end CPI-U for July 1991, we have recalculated the proposed adjustment, increasing operating expenses by $57,313.

Postage Expense

ULH&P proposed an increase of $17,731 to its operating expenses to reflect postage rate increases effective February 3, 1991 on an annual basis. ULH&P computed the increase by annualizing the cost of the test-year level of mail and then subtracting the actual mailing costs which reflected the period from February 3 through test-year end.

The Commission cannot accept the adjustment as proposed by ULH&P. In performing its calculations, ULH&P ignored the postage costs which were incurred at the old rates from the beginning of the test year until February 2, 1991. In effect, this adjustment contains a double count of postage expense for 6 months of the test year. We therefore reject the proposed adjustment.

The Commission also notes that the majority of mailings included in the proposed adjustment related specifically to ULH&P, such as customer bills and first class letters. ULH&P has indicated that its costs for these items are allocated to ULH&P by CG&E. The Commission does not believe it is appropriate for such mailing costs to be allocated when they should reflect direct charges. Customer bills and other ULH&P mailings must be specifically identified and directly charged to ULH&P's accounts rather than allocated.

Advertising Expenses

ULH&P proposed an adjustment to reduce operating expenses by $127,821 to reflect the elimination of institutional advertising as required by 807 KAR 5:016, Section 4. The charges eliminated represented the test-year-end balances of Account No. 913, Advertising Expenses, and Account No. 930.1, General Advertising Expenses. While making the adjustment in compliance with the regulation, ULH&P claimed that these expenses are necessary, recoverable business expenses, and should not be eliminated.[61] This position is the same one taken by ULH&P in Case No. 90-041.

In addition to ULH&P's adjustment, the AG proposed to remove the following additional expenses:

Customer Service & Information:	
Account No. 907 - Supervision	$ 69,211
Account No. 908 - Customer Assistance Expenses	766,201
Sales:	
Account No. 911 - Supervision	20,371
Account No. 912 - Demonstrating and Selling Expenses	171,110
Total	$1,026,893

The amounts for Accounts No. 907, 911, and 912 represent the entire test-year charges. The AG contends that these expenses are not appropriate for inclusion in rates because they reflect a massive effort by ULH&P to market its product without any cost justification.[62]

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61 Bruegge Direct Testimony, page 13.

62 DeWard Direct Testimony, page 24.

The Commission has been able in this proceeding to review with greater detail the advertising expenses of ULH&P than was available in Case No. 90-041. Some of the expenses recorded in Account No. 912 appear to be promotional in nature and are not allowable under 807 KAR 5:016. In addition to the advertising expense adjustment proposed by ULH&P, the Commission has reduced operating expenses by $66,779. This amount reflects the test-year charges to Account No. 912-40, Regional Marketing - Central Division; Account No. 912-41, Regional Marketing - Southern Division; Account No. 912-42, Regional Marketing, Planning & Community Development; and $5,833[63] in other specific Account No. 912 transactions.

AFUDC

ULH&P proposed an increase in revenues of $735,395 to reflect its annualization of AFUDC related to construction work in progress ("CWIP") subject to AFUDC as of test-year end. ULH&P computed its adjustment taking the electric CWIP subject to AFUDC and multiplying that amount by the AFUDC rate of 9.5 percent.[64]

63 $3,472 - Dektas & Eger, Inc., trade magazine ads; $1,499 - Associated Premium Corp., jar openers; and $862 - Community Profiles.

64 Response to the Commission's Order dated November 14, 1991, Item 33, page 43 of 43.

The AG proposed to remove ULH&P's book taxes associated with AFUDC, stating that without such an adjustment, tax expenses would be duplicated because of ULH&P pro forma adjustment.[65]

The methodology followed by ULH&P closely parallels that used by the Commission in determining an AFUDC offset to net operating income. However, ULH&P's approach used the AFUDC rate instead of the overall rate of return on capital and did not adjust the increase for the test-year-end electric balance in Account No. 432, AFUDC - Credit. An AFUDC offset adjustment consistent with previous ULH&P cases results in a more reasonable overall rate of return. ULH&P's net operating income is increased by $629,478 to reflect pro forma AFUDC of $782,361[66] for rate-making purposes.

Demand Side Management ("DSM") Incentive Payment

The AG proposed to remove a test-year incentive payment of $38,025 made by ULH&P relating to a customer's installation of a thermal energy storage system. The AG indicated that the installation was not completed during the test year, and there were no offsetting benefits associated with reduced demand or reductions in allocated costs. Therefore, in his view, it was inappropriate to include this cost for rate-making purposes.[67]

65 DeWard Direct Testimony, page 31.

66 $7,741,000 times 10.107% = $782,361.

67 DeWard Direct Testimony, page 25.

When asked if the test-year level of expense for all DSM activity reflected the normal, ongoing level of expense, ULH&P could not indicate whether the level would be higher, lower, or the same.[68]

The Commission realizes that ULH&P's DSM involvement is in its early developmental stages. The Commission encourages ULH&P in its DSM efforts. However, it must be displayed that some indication of expected ongoing levels of activity or similar incentive payments will be a recurring DSM expenditure. Operating expenses have been reduced by $38,025.

Hartwell Recreation Center ("Hartwell")

The AG proposed to reduce operating expenses $30,759 for operation and maintenance and rental charges associated with Hartwell, which is owned by CG&E. The AG stated that the Commission had removed similar expenses in Case No. 90-041 and that there was no reason to reverse that decision given the current economic situation.[69]

ULH&P indicated that the facility was used for training programs, recreational programs, and employee gatherings such as the annual Christmas party. While ULH&P stated that there were benefits to the ratepayers in having Hartwell, it could not quantify those benefits.[70]

68 T.E., Vol. III, March 19, 1992, page 183.

69 DeWard Direct Testimony, page 26.

70 T.E., Vol. II, March 18, 1992, pages 149 through 152.

We do not believe the costs to maintain recreation centers should be included for rate-making purposes. While these expenses may benefit employer/employee relations, the ratepayers should not bear these costs. Operating expenses have been reduced by $30,759.

Special Programs

The AG proposed to remove from operating expenses $39,019 related to numerous management training, assessment, and enhancement programs. The AG stated that given the current economic conditions, such programs were not needed to motivate ULH&P employees. The AG also argued that any incurred costs from these programs should be offset by future efficiencies.[71]

In order to be effective, a utility may need to undertake numerous types of training programs. Current economic conditions do not necessarily represent a positive motivating force to encourage a workforce. No adjustment is required.

Edison Electric Institute ("EEI") Dues

The AG proposed to remove $50,993 from operating expenses for EEI membership dues. The AG stated that EEI is an electric utility lobbying organization, whose primary interest is protection of shareholders.[72]

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71 DeWard Direct Testimony, pages 26 through 28.

72 Kinloch Direct Testimony, pages 62 through 65.

ULH&P indicated that it had not performed any cost/benefit analysis for the EEI dues. Further, ULH&P could not identify any specific benefits it or its ratepayers received from membership.[73]

The Commission is familiar with EEI and aware of the nature of its activities. We have excluded EEI membership dues in other rate proceedings when ratepayer benefit could not be demonstrated. Given the nature of EEI and ULH&P's lack of demonstrating ratepayer benefit of membership, the Commission has removed from operating expenses the allocated membership dues of $50,993.

Electric Power Research Institute ("EPRI") Membership Dues

The AG proposed a reduction in operating expenses of $601,136 for ULH&P's allocated share of membership dues in EPRI. The AG noted that ULH&P had not performed any cost/benefit analysis of its membership. The AG stated that since ULH&P was a distribution utility, the majority of EPRI research was of no direct benefit to ULH&P's ratepayers.[74]

As with EEI, the Commission is aware of the nature of EPRI's activities. We recognize that EPRI is a research organization funded by membership dues paid by member utilities. Applied EPRI research in generation, transmission, and distribution fields should be of benefit to ULH&P and its ratepayers, regardless of whether ULH&P is a generator or distributor. No adjustment is required.

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73 T.E., Vol. III, March 19, 1992, pages 184 and 189.

74 Kinloch Direct Testimony, pages 67 and 68.

Hay Associates

During the test year, ULH&P was allocated $1,731 in expenses related to Hay Associates.[75] Hay Associates performs annual reviews of ULH&P's and CG&E's salary structure.[76] ULH&P has indicated that Hay Associates does not submit written reports of its analysis.[77] While Hay Associates does maintain a utility salary data base, ULH&P also indicated that a significant amount of salary information used in the annual evaluation of salary structure was maintained in-house.[78] It is not clear what the function of Hay Associates is, and ULH&P has not adequately documented the benefit from the services provided by Hay Associates. Operating expenses are reduced by $1,731 to exclude this expense for rate-making purposes.

Employee-Related Expenses

The AG proposed to reduce expenses by $42,625 for items recorded in Account No. 926, Employee Pensions and Benefits. The AG stated that these expenditures represented inappropriate costs to include for rate-making purposes.[79] ULH&P responded that the

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75 Response to Staff Hearing Data Request No. 8.

76 Response to the Commission's Order, dated January 17, 1992, Item 68(d).

77 Id., Item 68(a).

78 T.E., Vol. IV, March 20, 1992, pages 115 through 117.

79 DeWard Direct Testimony, page 25.

charges to Account No. 926 were necessary to maintain good employee morale, which translated into good customer service.

As shown in Appendix D, expenses for employee picnics, children's Christmas parties, and charitable fund-raisers should not be included for rate-making purposes, reducing operating expenses by $2,572.

Miscellaneous Expenses

The AG proposed to reduce expenses by $65,142. This amount included $12,258 for a Christmas train display in CG&E's main office and $52,884 in miscellaneous expenditures. The AG argued that the train display only promoted the image of CG&E and had nothing to do with providing reliable electric service. The AG stated that the other miscellaneous expenses included items previously disallowed in Case No. 90-041 and expenses which appeared to have been misclassified as operating expenses rather than properly as donations.[80]

ULH&P claimed that the AG's adjustment eliminates expenses which are responsible for the efficient and reliable services provided by it to the community. ULH&P believes that these expenses are reasonable and necessary and should not be eliminated.[81]

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80 DeWard Direct Testimony, pages 28 through 30.

81 Lonneman Rebuttal Testimony, page 11.

It appears that several expenses that ULH&P has recorded on its books as operating expenses should have been recorded in Account No. 426.1, Donations. Several miscellaneous expenses identified by the AG are expenses we have disallowed in previous rate cases. The Commission has also identified other expenses that are not appropriate for rate-making purposes, including non-recurring items. A listing of the disallowed expenses totalling $69,032 is included in Appendix D. ULH&P shall review its accounting treatment of sponsorships and community programs and bring that treatment into compliance with the USoA's definition of Account No. 426.1.

The Commission, after consideration of all pro forma adjustments and applicable income tax effects, has determined ULH&P's adjusted net operating income to be as follows:

Operating Revenues	$148,824,021
Operating Expenses	153,832,122
AFUDC Offset	629,478
Net Operating Income	$(4,378,623)

RATE OF RETURN

Capital Structure and Debt Cost

ULH&P proposed to use its capital structure as of July 31, 1991 adjusted to include short-term debt and deferred investment tax credits.[82] The proposed capital structure included 48.80

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82 Mosley Direct Testimony, page 5.

percent long-term debt, 3.21 percent short-term debt, and 47.99 percent common equity.[83] ULH&P's long- term debt component was based on the carrying value of debt. The AG proposed to base long-term debt on the outstanding principal amount. The AG's position was that this method more accurately states the true liability of the company and is supported by return on rate base regulatory theory.

ULH&P's use of the carrying value is more appropriate. The carrying value reflects the unamortized debt discounts, premiums, and expenses at the date of calculation. This adjusted value more closely matches the current booked costs to ULH&P as opposed to the ultimate liability, and it is the booked costs that are appropriate to use in setting rates.

The cost of capital should be based on ULH&P's actual capital structure at July 31, 1991 consisting of 46.94 percent long-term debt, 7.11 percent short-term debt, and 45.95 percent common equity.

ULH&P proposed cost of long-term debt of 9.38 percent and cost of short-term debt of 7.58 percent based on an embedded cost of 9.27 percent as of July 31, 1991.[84] ULH&P updated its embedded cost of debt to December 31, 1991 reflecting long- term debt cost

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83 Calculated from ULH&P Exhibit JRM, pages 1-2, filed November 18, 1991.

84 Calculated from ULH&P Exhibit JRM, page 2, filed November 18, 1991.

of 9.375 percent and short-term debt cost of 5.935 percent.[85] Consistent with his recommendation on the debt component of capital structure, the AG calculated the cost of debt using average yield and yield to maturity. Consistent with ULH&P's determination of the debt component of capital structure its debt cost was calculated using interest expense less current amortization of debt discounts, premiums and expenses. As ULH&P's calculation more closely matches booked cost, we find the cost of long-term debt to be 9.375 percent and the cost of short-term debt to be 5.935 percent.

Return on Common Equity

ULH&P proposed a return on equity ("ROE") of 13.7 to 14.2 percent in its application.[86] ULH&P later determined its cost of common equity to be in the range of 13.4 to 13.9 percent.[87] The AG proposed the cost of common equity to be within the range of 10.25 to 11.25.[88]

To arrive at its requested return, ULH&P performed a discounted cash flow ("DCF") analysis and a risk premium analysis.

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85 Calculated from Revised ULH&P Exhibit JRM, page 2, filed March 17, 1992.

86 Mosley Direct Testimony, page 23.

87 T.E., Vol. I, March 17, 1992, page 125.

88 Weaver Direct Testimony, page 38.

For its DCF study ULH&P developed a proxy group of publicly traded utility companies to estimate its cost of equity as if it were a publicly traded independent company. ULH&P selected its proxy from combined gas and electric utilities reported in Value Line with bond ratings equivalent to ULH&P (BBB). ULH&P believes the proxy group is viewed by the financial community and investors as comparable risk companies.[89]

The DCF formula used by ULH&P reflects quarterly compounding of dividends and a 3.5 percent flotation cost adjustment.[90] ULH&P calculated an historical dividend growth rate of 6.7 percent for the period 1986-1990 and a projected dividend growth rate of 4.3 percent for 1994-1996. ULH&P concluded that a 5 percent growth rate is reasonable based on past and projected performance.[91] Based on stock prices for the 12 months ended February 29, 1992, ULH&P's DCF analysis produced a required ROE of 13.4 percent.[92] ULH&P concluded that it was more risky than its proxy and added a premium of 50 basis points to its DCF results to compensate for the difference in risk.[93]

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89 T.E., Vol. I, March 17, 1992, page 170.

90 *Mosley Direct Testimony*, page 10.

91 Id., page 17.

92 Revised ULH&P Exhibit JRM, page 4, filed March 17, 1992.

93 Mosley Direct Testimony, page 20.

ULH&P's risk premium analysis was based on a study by the Financial Analysts Research Foundation (updated by Ibbotson Associates, Inc.) on total rates of return for common stocks and bonds and the difference in average annual returns for the period 1926-1990. The study indicated an historical equity-debt risk premium of 4.9 percent.[94] To this, ULH&P added the current yield on its BBB rated bonds of 9.3 percent to arrive at a return on equity of 14.2 percent. ULH&P concluded that this result substantiates its DCF analysis.[95]

To perform a DCF analysis, the AG selected six companies he considered to be comparable to ULH&P. The AG determined his proxy group as combination gas and electric companies reported in <u>Value Line</u> with over 50 percent of revenues from electric and no nuclear facilities.

The AG averaged historical and forecasted rates to arrive at a growth rate of 3.25 to 4.25 percent for use in his DCF study. Based on stock prices for the period from October 18, 1991 - January 17, 1992 and adjusted for a 3.5 percent flotation cost adjustment, the AG's DCF study resulted in a cost of equity for ULH&P in the range of 9.86 to 10.92 percent.[96] Acknowledging an increased cost of equity to ULH&P due to lower interest coverage

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94 <u>Id.</u>, page 18.

95 <u>Id.</u>, page 19.

96 Weaver Direct Testimony, page 37.

than the comparable companies, the AG added a risk adjustment to arrive at his ultimate conclusion that the cost of equity to ULH&P is between 10.25 and 11.25 percent.[97]

Use of the quarterly dividend model for ULH&P's DCF analysis is inappropriate because investors would be doubly compensated.

ULH&P and the AG both proposed a 3.5 percent flotation cost adjustment in this case. ULH&P's adjustment was on the belief that a flotation cost adjustment is proper regardless of whether or not a new stock issuance is planned.[98] The AG's adjustment was on the belief of an expected need for external financing to fund ULH&P's construction budget over the next five years.[99]

ULH&P provided an analysis of flotation cost for its parent CG&E during the past 10 years and arrived at an average actual flotation cost of 3.57 percent.[100] Excluded from this average was a "bought" deal in which issuance cost were substantially lower than usual according to ULH&P. Stock may be issued through numerous means and the Commission does not believe the costs associated with a private placement should be excluded from an evaluation of actual cost. The AG merely accepted ULH&P's figure.[101]

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97 Id., page 36.

98 Mosley Direct Testimony, page 11.

99 Weaver Direct Testimony, page 35.

100 ULH&P Exhibit JRM, page 5, filed November 18, 1991.

101 Weaver Direct Testimony, page 36.

ULH&P would have the Commission believe that all of its equity capital is the result of public stock offerings; however, equity investment made by CG&E could come from other sources, such as CG&E's internally generated funds or debt.[102] The flotation cost adjustment should not be allowed because it overstates ULH&P's required return on equity. The percentage is not truly reflective of cost to CG&E and applicability to ULH&P.

The Commission has traditionally used the DCF model to assess comparable companies rather than companies of comparable risk. The two are not altogether in conflict. There is merit to comparable risk, in fact this would often be one of the selection criteria for comparable companies. ULH&P and the AG both used a mixture of historical and forecasted rates to determine growth. There is no compelling evidence that investors expect historical trends to continue into the future. A premium is not essential to account for ULH&P's greater risk relative to its proxy. If the proxy is truly of comparable risk then no additional adjustment is necessary.

The Commission has for a number of years considered the risk premium method for determining cost of common equity to be unreliable because it is subject to significant fluctuations due to the volatility of the bond and stock markets. The AG also disagreed with ULH&P's use of the risk premium method.

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102 Id., page 35-36.

Considering all factors, the risk premium study should not be utilized in this case.

The Commission affirms its traditional use of the DCF model to estimate ROE and continues to believe that the DCF method cannot be applied in a pure mechanistic manner. Considering all of the evidence, including current economic conditions, we find that the cost of common equity is within a range of 11.0 percent to 12.0 percent. Within this range, an ROE of 11.5 percent will best allow ULH&P to attract capital at a reasonable cost, maintain its financial integrity to ensure continued service and to provide for the necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers.

Rate of Return Summary

Applying the rates of 9.375 percent for long-term debt, 5.935 percent for short-term debt, and 11.5 percent for common equity to the capital structure produces an overall cost of capital of 10.11 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on ULH&P's jurisdictional net original cost rate base of 9.80 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

ULH&P needs additional annual operating income of $13,375,933 to produce a rate of return of 11.5 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, PSC Assessment, and increased uncollectibles, there is an overall revenue deficiency of $22,334,942 which is the amount of additional revenue granted.

The net operating income necessary to allow ULH&P the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $8,997,310. The required operating income and the increase in revenue allowed herein is as follows.

Net Operating Income Found Reasonable	$ 8,997,310
Adjusted Net Operating Income	(4,378,623)
Net Operating Income Deficiency	13,375,933
Gross Up Revenue Factor for Taxes, PSC Assessment, and Uncollectibles	1.66979
Additional Revenue Required	22,334,942

The additional revenue granted will provide a rate of return on the jurisdictional net original cost rate base of 9.80 percent and an overall return on total electric capitalization of 10.11 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $171,158,963.

PRICING AND TARIFF ISSUES

Cost-of-Service Studies

ULH&P and the AG both filed fully-allocated embedded cost-of-service studies for the year ending July 31, 1991. The assumptions and methodologies used by the two parties in developing the studies differ significantly, which explains the disparity that exists in the results of the studies.

The results of ULH&P's study indicate a significant variation in the contribution each class makes to the overall electric system rate of return of 10.28. The class rates of return as determined by ULH&P are as follows: Residential, 5.14; Distribution, 27.12; Transmission, 4.07; Lighting, 28.69; and Other, 41.27.[103] This study indicates that the Residential and Transmission classes are contributing less toward the system rate of return than the other classes.

The AG's study showed the following class contributions to the overall electric system rate of return of 10.28: Residential, 14.91; Distribution, 9.49; Transmission, -59.19; Lighting, 11.59; and Other, 38.67.[104] This study indicates that the Distribution and Transmission classes are contributing less than the other classes toward the system rate of return.

ULH&P used a 12 coincident peak ("12-CP") demand allocation factor to allocate demand-related production and transmission costs to customer classes. Under this method, all such costs are allocated to customer classes on the basis of each class's contribution to the 12 monthly maximum system peaks. The 12-CP method, like other peak demand methods, is predicated on the assumption that a utility's investment in production plant is determined only by system peak demands.

ULH&P divides distribution costs into demand-related and customer-related components by using percentages supposedly

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[103] Van Curen Testimony, Exhibit PVC-ECOS, Schedule 1.

[104] Kinloch Testimony, Exhibit DHK-6, Page 1 of 19, Schedule 1.

determined in a minimum-intercept study performed in a previous case.[105] Using this criteria, ULH&P classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. Demand-related distribution costs are then allocated on the basis of a class's non-coincident peak demand. Customer-related distribution costs are allocated based on the number of distribution customers. Various other plant and expense allocation factors were also used by ULH&P.

The AG allocated demand-related production and transmission costs using a variation of the average and excess method. This method recognizes that a portion of a utility's production plant is determined by durational or energy loads. The average and excess method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak demands.[106] The AG describes his allocation methodology as follows: "The amount of capacity associated with the average load is based on each class's contribution to the average load. The excess capacity above the average is allocated using ULH&P's 12 CP method."[107]

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105 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

106 National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual," revised in January 1992, page 49.

107 Kinloch Testimony, page 36.

In addition to the demand allocator, the AG modified three other allocators used by ULH&P. The first is ULH&P's allocator K414, which is used to allocate certain costs related to distribution plant. This allocator classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. The AG argued that distribution plant should be separated into primary and secondary components. ULH&P does not separate distribution plant in this manner. The AG maintains that the primary component should be allocated on the basis of system non-coincident peak, while the secondary component should be allocated on the basis of the summation of individual non-coincident peaks.[108] Using ULH&P's assumption that 80 percent of distribution costs are demand-related and 20 percent are customer-related, the AG allocated over three-fourths of the demand portion--the primary component--using his allocator A202 (average and excess at distribution). The remaining portion of demand-related distribution costs--the secondary component--are allocated using ULH&P's allocator K202 (total non-coincident KW).

Secondly, the AG modified ULH&P's administrative and general allocation factor K410. The AG claimed that a more accurate method of allocating these costs is based on the portion of other operating and maintenance expenses assigned to each class, less purchased power and fuel costs. Lastly, the AG modified ULH&P's allocator K206 (PSCKY net distribution plant less account 106) to

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108 Id., page 38.

reflect his allocation of distribution costs. The AG also modified several allocators assigned to individual plant and expense items.

The Commission finds numerous deficiencies in both cost-of-service studies presented in this case. In ULH&P's study, a 12-CP demand allocator is developed for the test year ending July 1991 by using load research and other data from time periods other than the test year. In fact, the most recent data used in developing the 12-CP demand allocation factor is from the year ending October 1990. Some of the data used in the development of this allocation factor is as much as 11 years old. In total, data from at least four different time periods, ranging from 1980 to 1990, are used in this calculation. The NARUC cost allocation manual states that the minimum data requirement for the 12-CP demand allocation method is reliable monthly load research data for each class of customers and for the total system.[109] As numerous variables, such as weather, economic factors, and appliance stocks and efficiencies fluctuate over time periods, it is very unlikely that data from so many different time periods is either reliable or representative of current conditions and, therefore, should not be used to calculate an allocation factor in this case.

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[109] NARUC's "Electric Utility Cost Allocation Manual," revised in January 1992, page 46.

ULH&P did not perform a minimum-intercept or zero-intercept study in this case in order to divide distribution costs into demand-related and customer-related components. When asked how it determined the percentages of demand-related and customer-related distribution plant, ULH&P claimed to have performed a minimum-intercept study.[110] However, ULH&P could not determine when such a study was performed.[111] The Commission has determined that ULH&P did not perform a minimum-intercept or zero-intercept study in Case No. 90-041[112] and cannot determine whether ULH&P performed such a study in Case No. 9299[113] (the rate case preceding Case No. 90-041). Even if such a study was performed in Case No. 9299, it is doubtful that the results of the study, which depend on current and detailed distribution plant and cost data, would still be reliable, as that case was decided in October 1985.

The AG criticizes ULH&P's failure to divide distribution plant into primary and secondary components and to allocate each component using separate allocation factors. ULH&P claims that it

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110 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

111 T.E., Volume II, page 141.

112 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company.

113 Case No. 9299, An Adjustment of Electric Rates of The Union Light, Heat and Power Company.

does not maintain its accounting records in that manner as such a separation of distribution costs into primary and secondary components is not required by the USoA established by the Federal Energy Regulatory Commission.[114] NARUC states that "in order to recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications."[115] The Commission believes that, given the distinct voltage characteristics of distribution facilities, a separation of certain distribution costs into primary and secondary components is appropriate and necessary. ULH&P should begin separating distribution facilities into primary and secondary components for use it its next cost-of-service study.

The AG's cost-of-service study presents its demand allocation methodology as an "average and excess" method. However, as pointed out by ULH&P, the AG's calculation of this allocation factor differs significantly from that prescribed by the NARUC in its "Electric Utility Cost Allocation Manual."[116] The AG admitted

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114 T.E., Vol. II, page 140.

115 NARUC's "Electric Utility Cost Allocation Manual," revised January 1992, page 89.

116 ULH&P's Brief, pages 26-27.

that the NARUC method did not achieve the results he wanted, so he modified it according to his own assumptions and judgment.[117] The modifications made by the AG to the average and excess methodology are inconsistent with the methodology prescribed by NARUC and are inappropriate for the allocation of production and other demand-related costs.

Distribution costs should be separated into primary and secondary components. NARUC considers such a division of distribution costs necessary and other utilities presenting cost-of-service studies before this Commission have made such a bifurcation. However, partly because of unavailable data from ULH&P, the AG divides these costs by using percentages found to be appropriate by Louisville Gas and Electric Company ("LG&E") and Kentucky Power Company ("KPC") in recent rate cases.[118] It is unreasonable to assume that the primary and secondary split in LG&E's and KPC's distribution plant is at all similar to that of ULH&P. The make-up of each utility's distribution plant is unique and cannot be used as a proxy for another utility.

The AG used and modified several of the allocation factors developed by ULH&P in its cost-of-service study. Some of these factors have been improperly calculated by ULH&P, infra. The AG's use of these improper factors renders the AG's calculations

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117 AG's Response to Item 10 of ULH&P's Information Request dated February 10, 1992.

118 T.E., Vol. V, March 23, 1992, page 98.

inappropriate. The most obvious cases are the AG's use of ULH&P's 12-CP demand allocation factor (K200) in the calculation of the AG's average and excess allocator and the use of ULH&P's division of distribution plant as 80 percent demand-related and 20 percent customer-related in the AG's calculation of primary and secondary distribution plant components.

The Commission finds that both cost-of-service studies presented in this case are inappropriate, unreliable and should be rejected.

The Commission is aware of the on-going debate regarding the appropriate methodologies to be used to allocate demand-related plant and expense items. In cost-of-service studies presented in this case, ULH&P advocated the use of a 12-CP demand method while the AG used a modified "average and excess" method. The 12-CP demand method belongs to the family of peak demand methods, while the average and excess method is a type of energy weighting method.

The most fundamental difference between these two methodologies is the way in which a utility's investment in production plant is viewed. Proponents of a 12-CP or other peak demand method claim that a utility's production plant is built only for the purpose of serving peak load, whether individual monthly peaks or the annual system peak. Thus, all demand-related production costs must be allocated to customer classes on the basis of each class's contribution to the system peak. Under this scenario, if a customer class, such as street lighting, does not use the system at the time of system peak, no production costs would be allocated to it. Proponents of an average and excess method or some other energy weighting method claim that a utility's production plant is built not only to serve peak demand but also to serve off-peak base load. For this reason, all classes should bear some of the costs of producing electricity regardless of a class's use of the system at the time of system peak. There are also time-differentiated methodologies such as the Base-Intermediate-Peak ("BIP") method that allocate production plant costs to off-peak baseload hours, intermediate "shoulder peak" hours, and peak hours. ULH&P and other interested parties may want to refer to the description of these methodologies as set forth in the NARUC's "Electric Utility Cost Allocation Manual" which was revised in January 1992.

Over the years, the Commission has accepted cost-of-service studies that used demand allocation methodologies from each of these different categories. There are convincing arguments that can be made for any of these methods. For this reason, the Commission recommends that, in future rate cases, ULH&P file multiple cost-of-service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies. To the extent possible, intervenors should also present multiple cost-of-service studies using various methodologies. By having multiple cost-of-service studies presented in rate cases, the Commission is convinced that a more reasonable and informed decision can be made regarding the appropriate allocation of revenue to customer classes.

Revenue Allocation

Based on the results of its cost-of-service study, ULH&P proposed to allocate its requested increase as follows: 24.7 percent to the residential class; 16.7 to 18.9 percent to the commercial and industrial classes; and approximately 10.3 percent to its lighting classes. The AG, based on his cost-of-service study and assuming the full increase was granted, proposed 19 to 20 percent increases for residential and commercial customers, an approximate 30 percent increase for industrial customers, and an approximate 10 percent increases for ULH&P's lighting class customers.

Inasmuch as the Commission has rejected both of the proposed cost-of-service studies neither study will be used to allocate the revenue increase. The increase will be allocated to ULH&P's customer classes in the same proportions each class currently contributes to ULH&P's total electric revenues. This approach, which is traditionally utilized when no cost-of-service study has been presented, maintains the existing allocation between classes and results in each class receiving approximately the same overall percentage increase. In this instance, all classes will receive increases of approximately 15 percent.

Residential Rate Design

The AG proposed that ULH&P's residential rates, which consist of a flat summer rate and a two-step declining block winter rate, be restructured to include inverted (inclining block) rates both in summer and winter. While the first step of the existing winter rate encompasses 0 to 1,000 KWH, the AG would have the first step of the two-step rate cover only 0 to 700 KWH. Based on his analysis of ULH&P's monthly power costs, the AG opined that, under ULH&P's existing rate structure, temperature-sensitive power is being underpriced and customers are being encouraged to overuse or waste energy, resulting in higher costs for all customers.

ULH&P opposed the AG's proposal arguing that reducing the first block to 700 KWH would be cutting into non-temperature sensitive loads and would be punitive to its all-electric customers. ULH&P contends that its existing winter rate design, with the break point at 1,000 KWH, properly recognizes its all-electric customers usage patterns and should not be changed absent end-use data which would support such a change. ULH&P also contested the AG's determination of baseload costs and temperature-sensitive load costs, two components in the AG's calculation of inverted rates.

The AG's proposal has some merit in light of ULH&P's summer load characteristics. ULH&P's cooling load is the primary force driving its predominant summer peak while it experiences its heating load during its off-peak (winter) season. The Commission recognizes that increased off-peak demands can produce many of the same benefits as reduced on-peak demands, such as improved system load factor and lower unit costs. Given these circumstances, the Commission finds that ULH&P's residential rates should be modified to include an inverted block summer rate but should retain a declining block winter season rate. The Commission shares ULH&P's concerns about reducing the break point in its residential rate schedule without the benefit of end-use data and, therefore, will maintain the existing break point of 1,000 KWH. We are, however, interested in pursuing this matter further in ULH&P's next general rate case. ULH&P shall address the appropriate structure of its residential rates in that case. In keeping with our stated goals of gradualism and rate continuity, the Commission will take a moderate approach to implementing an inverted summer rate by increasing the second rate block by approximately one-and-one-half times the increase to the first block.

Bad Check Charges

ULH&P proposed to increase from $8 to $15 its charge for receiving and processing bad checks to serve as a deterrent to customers that might issue such checks. ULH&P indicated the proposed charge was comparable to the charges assessed by local businesses and financial institutions.

The AG opposed the increase, claiming that publicizing the existing charge would serve as a more effective deterrent than increasing the charge by 87 percent. The AG argued that the proposed charge is not cost based and that any increase should be limited to the level of the overall increase granted in this case.

ULH&P has not provided sufficient cost support to justify the requested $7 increase in the bad check charge. Customers must be aware of the charge before it can become an effective deterrent. In the absence of cost support, the charge should remain at $8.

Late Payment Charges

The AG proposed that the Commission direct ULH&P to change the way in which it credits partial payments from customers carrying a past-due balance from a previous month. The proposal would require that, when a customer pays enough to cover the current month's bill plus at least $5 toward the past-due balance, the payment should first be credited to the current month's bill rather than to the customer's oldest balance first. The AG argued that such a change was needed to eliminate the practice of a customer paying late payment charges month after month when the customer wasn't late in paying his bill but was merely unable to pay the full amount of his current bill and his past-due balance.

ULH&P opposed the proposal arguing that the AG was wrong in claiming that a customer could pay a late payment charge on the same balance month after month under the existing late payment provision. ULH&P contends that a late payment charge is applied to a past due balance only once under its current procedure.

The Commission is persuaded to adopt the AG's proposal. The proposal will apply only when the customer pays his current month's bill in full and makes a contribution of at least $5 toward his past due balance. While leaving intact ULH&P's late payment provision, the proposal will remove the customer's disincentive for making a timely partial payment by eliminating the recurrence of a late payment charge.

<u>Rate and Tariff Changes</u>

ULH&P proposed few structural changes to its existing rates or tariff schedules. ULH&P did propose to modify its electric space heating tariff, Rate EH, an optional rate for non-residential customers having a demand of less than 500 KW. The modification would remove the rate's limitation to customers receiving similar service prior to June 25, 1981. ULH&P proposed to add a second step to Rate GS-FL for general service fixed loads of less than 540 hours use per month. ULH&P also proposed to add a rate step for traffic lighting service to cover situations where company personnel provide limited maintenance for traffic signal equipment but energy is supplied from a separately-metered source. On its outdoor lighting schedule, Rate OL, ULH&P proposed to delete and add various lighting units and to give customers the option of making a one-time up-front contribution for a decorative unit in order to reduce the regular monthly charge to that of a standard unit. On its non-standard private lighting schedule, Rate NSP, ULH&P proposed to limit the availability of some units to those customers served at the time this application was filed.

The changes described above and other text modifications proposed by ULH&P were not contested by any party. The Commission has reviewed these changes and finds they should be approved with the exception that the limitations on Rate NSP shall be prospective from the effective date of this Order. The new rate steps and new lighting units are set out in Appendix A. The text changes are not included in the Appendix.

MANAGEMENT AUDIT

General

In its final Order in Case No. 90-041, the Commission expressed several concerns with ULH&P's response to the 1989 management audit performed by Schumaker & Company. The Commission clearly stated that it found it appropriate to review ULH&P's audit-related activities in formal rate case proceedings. In addition, the Commission stated that it considered the audit report "to constitute substantial evidence regarding potential cost savings measures available"[119] to ULH&P and also clearly indicated that adjustments related to the management audit recommendations may be considered in future rate proceedings.

In this proceeding, ULH&P initially provided a schedule of test-year costs and benefits attributable to the implementation of management audit recommendations.[120] That schedule reflected "Per Auditor" and "Per Company" costs and benefits for 53 recommendations. In response to a request for specific detailed information relating to the schedule, ULH&P indicated that a schedule with the information and level of detail requested did not exist.[121] ULH&P subsequently disclosed that there were several errors in that schedule, and that it does not have the accounting mechanisms in place to specifically identify allocated individual recommendation costs in the test year.[122] ULH&P has also stated that creating and maintaining a special detailed reporting system to track the success of implemented management audit recommendations would be prohibitively expensive and a waste of manpower and resources.[123]

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119 Id., page 76.

120 Response to the Commission's Order dated November 14, 1991, Item 49.

121 Response to the Commission's Order dated December 17, 1991, Item 63.

122 Response to the Commission's Order dated January 17, 1992, Item 47.

123 Id., Item 48.

However, in a December 1991 summary report of ULH&P's implementation progress prepared by the Commission's Management Audit Branch, which was reviewed by ULH&P prior to publication, 11 recommendations with a net savings or cost avoidance of $987,400 to $995,400 were identified as being implemented. Four recommendations with an identified savings of $803,000 were directly related to the Electric Operations Department and four recommendations with an identified savings of $52,900 to $60,900 were in the Customer Service or Administrative services area and were indirectly related to Electric Operations.[124] The amounts included in the summary report were derived from ULH&P's progress reports submitted to the Management Audit Branch as part of the management audit follow-up process.

If such information can be provided in regular periodic reports to the Commission's Management Audit Branch but cannot be addressed with any certainty in a rate proceeding, the Commission must not only question the accuracy of the savings identified by ULH&P in its periodic progress reports but also the intentions of ULH&P to follow through on its actions to achieve these savings.

While recognizing that savings and efficiency enhancements are not always represented by actual reductions in current dollars

124 Summary Report: The Union Light, Heat And Power Company's Progress In Implementing The Management Audit Recommendations, dated December 1991.

but may also represent future avoided costs, the Commission believes that successful implementation of reasonable and appropriate audit recommendations provides benefits to both ULH&P's customers and shareholders. The customers benefit to the extent that increased productivity and efficiency allow ULH&P to meet its service obligations more economically. This, in turn, benefits the owners by enhancing ULH&P's ability to earn its authorized rate of return.

As audit recommendations are implemented, the Commission fully expects ULH&P to provide appropriate cost/benefit analyses supporting its efforts in the periodic progress reports and, when requested, in rate proceedings. To ensure that customers, as well as owners, receive the benefits of implemented recommendations, the Commission, in future rate proceedings, will require ULH&P to provide appropriate detailed information of costs, benefits, and/or costs avoided as a result of its related efforts regardless of the accounting or reporting mechanisms now in place. This information should correspond to the information periodically provided to the Commission's Management Audit Branch, or a fully detailed explanation of differences should be provided. If costs and benefits are not adequately addressed in future rate proceedings, the Commission will make appropriate adjustments.

In requiring this information, the Commission is not requesting ULH&P to develop additional reporting procedures. We are, however, requiring ULH&P to comply with the requirements of the USoA which requires utilities to keep their books of account and all supporting documentation in a manner as to be able to readily furnish full information as to any item included in any account.[125]

Individual Recommendations

ULH&P indicated that it understood that three recommendations were subject to discussion and determination by the Commission.[126] Since ULH&P further addresses these three "agree to disagree" recommendations and requests that the Commission determine how they are to be resolved,[127] the Commission will address each recommendation.

With regard to the recommendation to request additional feedback from the external auditors, the Commission does not fully agree with ULH&P's and the Board of Directors' Audit Committee's position regarding formal written communication. However, considering the decision of management and that other appropriate procedures are in place, the Commission will require no further action relative to this recommendation. Should the situation change or problems arise, however, the Commission fully expects appropriate changes to be instituted.

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125 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 2(A).

126 T.E., Vol. IV, March 20, 1992, page 80.

127 Brief of ULH&P, pages 33 through 36.

With regard to the recommendation to assign responsibility for salary administration, at all levels of the organization, to the Human Resource Department's Compensation and Benefits Division, the Commission finds that the decision to leave administration of management employees' compensation with the Assistant Secretary rather than transfer responsibility to the seemingly more appropriate Human Resources group to be inconsistent with the Commission's understanding of the typical duties and responsibilites of a human resource function. There is evidence regarding the reorganization of the human resource function and changing corporate culture.[128] No further action will be required at this time. However, with the changes taking place in the human resources area, the Commission would expect ULH&P to reconsider this recommendation should administration by the Human Resource function become appropriate.

With regard to the recommendation that ULH&P's Legal Department develop time sheets to record actual charges to ULH&P in enough detail to identify specific projects and services, the Commission will require that this recommendation be reconsidered and included in any determination made by ULH&P regarding the supervisory, administrative, and professional cost-allocation and time study issues addressed earlier in this Order.

To the extent that other recommendations remain ongoing or not completely implemented, the Commission fully expects ULH&P and

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128 T.E., Volume III, March 19, 1992, pages 81 through 84, 143 through 148 and Volume IV, March 20, 1992, page 69.

CG&E (to the extent that such recommendations impact ULH&P) to make a good faith effort to satisfactorily report on implementation or provide specific detailed analyses to show why implementation is not reasonable.

With respect to recommendations that are ULH&P specific or are indirectly related to ULH&P, that are being studied as part of ULH&P's integrated operations, the Commission strongly believes that specific consideration should be given to the needs of the ULH&P service area and to its customers. As the management auditors stated, ULH&P, as an integral part of CG&E, should be in a position to benefit from a level of sophistication of management and technology that it would not otherwise be able to justify.[129] However, the evidence presented in this proceeding relative to recent increases in staffing levels, the failure of ULH&P to perform the referenced analysis of staffing levels, the inability or unwillingness to adequately address cost allocation issues, and the inability to address the specific costs and benefits of the management audit, raises significant questions as to whether Kentucky customers are indeed benefiting from this relationship.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

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129 Management And Operations Review of The Union Light, Heat And Power Company, August 1989, page 29.

1. The rates in Appendix A, attached hereto and incorporated herein, are the fair, just, and reasonable rates to be charged subject to refund by ULH&P for service rendered on and after the date of this Order.

2. The rates proposed by ULH&P would produce revenue in excess of that found reasonable herein and should be denied.

3. The rate of return granted herein is fair, just, and reasonable, and will provide for the financial obligations of ULH&P with a reasonable amount remaining for equity growth.

4. The tariff changes proposed by ULH&P, as modified herein, are reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved subject to refund for service rendered by ULH&P on and after the date of this Order.

2. ULH&P shall maintain its records in such manner as will enable ULH&P, any of its customers, or the Commission to determine the amounts to be refunded and to whom due in the event a refund is ordered.

3. ULH&P shall file a notice with the Commission, with a copy to all parties of record, within 5 days of any change in the current FERC filed rate for purchased power.

4. The rates proposed by ULH&P be and they hereby are denied.

5. The tariff changes authorized herein and the tariffs set forth in Appendix A be and they hereby are approved.

6. Within 30 days from the date of this Order, ULH&P shall file with the Commission revised tariff sheets setting out the rates and tariff provisions approved herein.

Done at Frankfort, Kentucky, this 5th day of May, 1992.

PUBLIC SERVICE COMMISSION

Chairman

Commissioner

DISSENTING OPINION OF VICE CHAIRMAN THOMAS M. DORMAN

I respectfully dissent from the decision to allow ULH&P to increase its retail rates by approximately $25 million to recover increased purchase power costs due solely to the commercialization of Zimmer. CG&E's cost to convert the substantially completed nuclear facility to a coal facility should be borne by CG&E's shareholders and not by Kentucky ratepayers. There is no valid reason to justify the cost of Zimmer being at least 50 percent greater than the current cost for comparable generation.

While the rate increase authorized by the majority is subject to refund pending a full and comprehensive review of the Zimmer cost by the FERC, I strongly believe that ratepayers should not be burdened with excessive and uncertain Zimmer costs during the interim. This Commission has intervened at the FERC and will soon be sponsoring expert testimony on the unreasonableness of Zimmer's cost. As long as the Kentucky Public Service Commission is an intervenor and until the FERC has considered all the evidence and approved a final rate for purchased power, this Commission should object to any scheme which seeks to recover unreasonable Zimmer costs from Kentucky ratepayers.

Thomas M. Dorman
Vice Chairman

ATTEST:

Executive Director, Acting

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN WATER COMPANY FOR AN ADJUSTMENT OF RATES SUPPORTED BY A FULLY FORECASTED TEST YEAR	))))	CASE NO. 2010-00036

O R D E R

Kentucky-American Water Company ("Kentucky-American") proposes to adjust its base rates for water service and increase its tap-on fees. The proposed rates, which were based upon a fully forecasted test period ending September 30, 2011, would produce additional revenues of $25,848,286, or 39.9 percent, over forecasted operating revenues from existing water rates of $64,753,488.[1] By this Order, the Commission establishes rates for water service that will produce an annual increase in revenues from water sales of $18,825,137 and approves the requested increase in tap-on fees.

BACKGROUND

Kentucky-American, a Kentucky corporation, owns and operates facilities that treat and distribute water, for compensation, to approximately 118,759 customers in the counties of Bourbon, Clark, Fayette, Gallatin, Grant, Harrison, Jessamine, Owen, Scott,

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[1] As required by KRS 278.192(2)(b), Kentucky-American submitted its base period update on July 15, 2010 to report the actual results for the base period months that were originally forecasted. This update contains corrections of certain errors that result in a revised revenue increase of $25,302,362, or $545,924 below the originally proposed increase.

PSC – EXHIBIT 3

and Woodford.[2] It provides wholesale water service to Jessamine-South Elkhorn Water District, Harrison County Water Association, East Clark Water District, and the cities of Georgetown, Midway, Versailles, North Middletown, and Nicholasville.[3] It is a utility subject to Commission jurisdiction.[4] Kentucky-American last applied for a rate adjustment in 2008.[5]

PROCEDURE

On January 27, 2010, Kentucky-American notified the Commission in writing of its intent to apply for an adjustment of rates using a forecasted test period. On February 26, 2010, it submitted its application. The Commission established this docket[6] and permitted the following parties to intervene in this matter: the Attorney General of Kentucky ("AG"), Lexington-Fayette Urban County Government ("LFUCG"), and Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC").

On March 17, 2010, the Commission suspended the operation of the proposed rates for six months and established a procedural schedule for this proceeding. Following extensive discovery, the Commission held an evidentiary hearing in this

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[2] *Annual Report of Kentucky-American Water Company to the Public Service Commission for the Calendar Year Ended December 31, 2009* at 5, 30.

[3] *Id.* at 33.

[4] KRS 278.010(3)(d).

[5] Case No. 2008-00427, Application of Kentucky-American Water Company for A General Adjustment of Rates Supported by A Fully Forecasted Test Year (Ky. PSC Jun. 1, 2009).

[6] On February 16, 2010, the Commission granted Kentucky-American's request for the use of electronic filing procedures in this proceeding and authorization for the service of all documents upon all parties by electronic means only.

matter on August 10-11, 2010 in Frankfort, Kentucky.[7] We also held a public hearing in Lexington, Kentucky on July 28, 2010 to receive public comment on the proposed rate adjustment. All parties submitted written briefs following the conclusion of the evidentiary hearing.

On September 28, 2010, Kentucky-American notified the Commission of its intent to place the proposed rates into effect for service rendered on and after September 29, 2010. In response, we directed Kentucky-American to maintain appropriate records of its billing to permit any necessary refunds.

ANALYSIS AND DETERMINATION

Test Period

Kentucky-American used as its forecasted test period the twelve months ending September 30, 2011. The base period was the twelve months ending May 31, 2010.

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[7] The following persons testified at the evidentiary hearing: Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC; Linda C. Bridwell, Manager-Water Supply, Kentucky-American; Keith Cartier, Vice-President of Operations, Kentucky-American; Paul R. Herbert, President, Valuation and Rate Division, Gannett Fleming, Inc.; Michael A. Miller, Assistant Treasurer, Kentucky-American; Sheila A. Miller, Manager-Rates and Service, Eastern Regional Service Company Office, American Water Service Company; Nick O. Rowe, President, Kentucky-American; John J. Spanos, Vice-President, Valuation and Rate Division, Gannett Fleming, Inc.; James L. Warren, Partner, Winston & Strawn LLP; Lance W. Williams, Director of Engineering, Kentucky-American; Ralph C. Smith, Senior Consultant, Larkin & Associates, PLLC; and Jack E. Burch, Executive Director, CAC. By agreement of the parties, the following persons submitted written testimony but did not make a personal appearance at the evidentiary hearing: James H. Vander Weide, Professor of Finance and Economics, Duke University; J. Randall Woolridge, Professor of Finance, Pennsylvania State University; Edward L. Spitznagel, Jr., Professor of Mathematics, Washington University; and Richard A. Baudino, Consultant, J. Kennedy and Associates, Inc.

Rate Base

Kentucky-American proposes a forecasted net investment rate base of $362,672,028.[8] The Commission accepts this forecasted rate base with the following exceptions:

Utility Plant in Service ("UPIS"). Kentucky-American uses capital construction budgets to determine its forecasted UPIS amount of $566,014,484.[9] A major component of Kentucky-American's forecasted UPIS is the $164 million cost of the Kentucky River Station II ("KRS II") project, which Kentucky-American placed into service on or about September 20, 2010. On April 25, 2008, the Commission granted Kentucky-American a Certificate of Public Convenience and Necessity to construct KRS II, approximately 30.6 miles of 42-inch transmission main to transport treated water to its Central Division distribution system, and a booster station in Franklin County.[10] Kentucky-American attributes $23,579,000, or approximately 91 percent, of its total requested rate increase of $25,848,000 to KRS II's construction and placement into service.[11]

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[8] Application, Exhibit 37, Schedule B-1 at 2.

[9] *Id.*

[10] Case No. 2007-00134, The Application of Kentucky-American Water Company For a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main (Ky. PSC Apr. 25, 2008).

[11] Direct Testimony of Michael A. Miller at 4.

Kentucky-American separates its construction budgets into three categories: normal recurring construction, construction projects funded by others,[12] and major investment projects. In prior rate proceedings, the Commission has adjusted forecasted UPIS to reflect 10-year historical trend percentages of actual-to-budgeted construction spending.[13] We noted:

> Budgeting being an inexact science, it is imperative that the historical relationship between the budgets and actual results be reviewed to determine what projects Kentucky-American is likely to have in service or under construction in the forecasted period. A forecasted period does not preclude the examination of historic data and trends but, rather, compels their examination to test the historic to forecasted relationships. Nor will an adjustment based on the historical slippage factor have a devastating impact on Kentucky-American's earning potential. Such an adjustment will have a minimal impact on revenue requirements by eliminating a return on utility plant not in service during the forecasted period due to delayed investment.[14]

These "slippage factors" thus serve as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions and the time period during which new plant will be placed into service.

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[12] Contributions in Aid of Construction or Customer Advances, which are forms of cost-free capital, fund these projects.

[13] Case No. 92-452, Notice of Adjustment of Rates of Kentucky-American Water Company, at 9-11 (Ky. PSC Nov. 19, 1993); Case No. 95-554, The Application of Kentucky-American Water Company to Increase Its Rates, at 2-3 (Ky. PSC Sep. 11, 1996); Case No. 97-034, The Application of Kentucky-American Water Company to Increase Its Rates, at 3-7 (Ky. PSC Sep. 30, 1997); Case No. 2000-120, The Application of Kentucky-American Water Company to Increase Its Rates, at 2-4 (Ky. PSC Nov. 27, 2000); and Case No. 2004-00103, Adjustment of the Rates of Kentucky-American Water Company, at 3-4 (Ky. PSC Feb. 28, 2005).

[14] Case No. 92-452, Order of Nov. 19, 1993, at 9.

Based upon the evidence in the record, we find the slippage factors for normal recurring construction and major investment projects are 120.86 percent and 90.80 percent, respectively.[15] By applying these factors to its capital construction budgets, Kentucky-American recalculated its forecasted UPIS to be $569,054,823, or $3,040,399 greater than the original forecasted UPIS of $566,014,484.[16]

The AG objects to the application of any slippage factor in the current proceeding. He contends that slippage factors were originally intended to protect ratepayers from Kentucky-American's historical tendency to overestimate its construction spending and to serve as a safeguard to ensure that ratepayers did not bear the cost of paying a return for UPIS that would not be placed in service in the test period.[17] A "reverse-slippage" adjustment, the AG asserts, is unnecessary because "slippage was never intended to be a double-edged sword that cuts both ways; rather, the intent of the factor was a scalpel for the purpose of excising the risk associated with Kentucky-American's over-budgeting in setting rates."[18]

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[15] Kentucky-American's Response to Commission Staff's First Information Request, Item 9.

[16] Kentucky-American's Response to Commission Staff's First Information Request, Item 36, Schedule B-1 at 2.

[17] AG's Brief at 18.

[18] *Id.*

We disagree with the proposition that slippage factors were intended solely to protect ratepayers. Their purpose is to produce a more accurate, reasonable, and reliable level of forecasted construction.[19] The application of slippage factors in this proceeding is consistent with that purpose and with the Commission's past practice in every rate case decision in which Kentucky-American proposed a rate adjustment based upon the use of a forecasted test period. Accordingly, we find that Kentucky-American's forecasted UPIS should be increased by $3,040,399 to reflect the application of slippage factors.

Accumulated Depreciation. In its application, Kentucky-American uses a 13-month average of its accumulated depreciation balances for the period from September 2010 through September 2011 to arrive at its forecasted accumulated depreciation of $110,085,251.[20] Adjusting Kentucky-American's forecasted accumulated depreciation to reflect the effect of construction slippages results in an increase of $62,956 for an adjusted balance of $110,148,207.[21]

In this application, Kentucky-American submits a recently completed depreciation study to support its forecasted depreciation. This study was based upon Kentucky-American's utility plant as of November 30, 2009.[22] In calculating the depreciation

[19] *See, e.g.*, Case No. 95-554, Order of Sep. 11, 1996, at 5 ("The 10 year slippage factor . . . produces a more reliable estimate of the construction projects Kentucky-American will have in service or under construction in the forecasted period.").

[20] Application, Exhibit 37, Schedule B-1 at 2.

[21] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1 at 2.

[22] John J. Spanos, *Depreciation Study - Calculated Annual Depreciation Accruals Related to Utility Plant at November 30, 2009*, at I-1 (Gannett Fleming, Inc. Feb. 18, 2010) ("*Depreciation Study*").

accrual rates in this study, however, Kentucky-American failed to consider KRS II's projected cost.[23] Kentucky-American subsequently revised its study to reflect the cost of its forecasted UPIS as of December 31, 2010, which included KRS II costs of $163,891,660.[24] This revision reduces forecasted accumulated depreciation by $130,773.[25]

While generally accepting the findings of Kentucky-American's revised depreciation study, the AG asserts that the findings regarding Account 333, Services, are unsupported by credible evidence and appear suspect.[26] He notes that Kentucky-American proposes a negative net salvage value of 100 percent for this account, which is much higher than the negative net salvage value for other accounts.[27] He further notes that the study is missing information from calendar years 1995, 1996, 1997, and 1998 and that, although the study period involved 30 years, approximately 42 percent of the regular retirements for Account 333 occurred in 2007 and 2008.[28] Finally, he notes that the three-year moving averages for Account 333 for the last three years vary

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[23] Direct Testimony of John J. Spanos at III-4 through III-11.

[24] Kentucky-American's Response to Commission Staff's Second Information Request, Item 43.

[25] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[26] AG's Brief at 23.

[27] Public Direct Testimony of Ralph C. Smith at 69.

[28] *Depreciation Study* at III-106.

significantly from the study's findings.[29] Accordingly, the AG argues that Kentucky-American has failed to meet its burden of proof to demonstrate the reasonableness of the proposed depreciation rate for this account.

Notwithstanding the AG's argument, we find sufficient evidence to support the study's findings. We note that the study was based upon historical data gathered over a 30-year period and the study's methodology was systematically applied to all accounts. The AG has not suggested, nor do we find any evidence to indicate, that the utility concealed data or the report's preparers deliberately ignored data.[30] The AG has not suggested that the report's methodology was incorrectly applied or was contrary to industry-wide standards. Our review of the study indicates that its methodology is consistent with that of other depreciation studies that the Commission has accepted.[31]

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[29] AG's Brief at 23. The three year moving averages for Account 333 are shown below:

3 Year Periods	Negative Percentages
2005 – 2007	41%
2006 – 2008	17%
2007 – 2009	19%

[30] The AG's acceptance of the study's findings for accounts other than Account 333 weakens his argument regarding Account 333. Data for a four-year period was not available and therefore not used in the study to calculate net salvage value for several accounts. If the lack of available data does not render the study's findings invalid or suspect for these other accounts, it logically follows the lack of data should not affect the study's findings for Account 333.

[31] *See, e.g.*, Case No. 9093, Application of Kentucky-American Water Company for Certification of Depreciation (Ky. PSC Mar. 21, 1985); Case No. 90-321, Notice of Adjustment of The Kentucky-American Water Company Effective on December 27, 1990 (Ky. PSC May 30, 1991); Case No. 95-554, Order of Sep. 11, 1996; Case No. 2007-00143, Adjustment of Rates of Kentucky-American Water Company (Ky. PSC Nov. 29, 2007).

Accordingly, the Commission finds that the AG's proposed adjustments to accumulated depreciation should be denied. We further find that accumulated depreciation should be adjusted to reflect the impact of slippage and the results of the revised depreciation study, which results in a net decrease to accumulated depreciation expense of $67,817.

Construction Work in Progress ("CWIP"). Kentucky-American forecasts CWIP includable in rate base as $9,463,931.[32] When adjusted for slippage, CWIP balance is $9,438,488.[33]

Arguing that CWIP should not be included in rate base unless a utility demonstrates compelling reasons for that treatment, such as a large project that cannot be financed without seriously jeopardizing the utility's financial health, and that Kentucky-American has failed to offer such reasons, the AG proposes to eliminate all CWIP balance from Kentucky-American's rate base.[34] AG witness Smith argues that CWIP does not represent facilities that are used or useful in the provision of utility service.[35] Including this plant in rate base, he argues, requires current ratepayers to pay a return on plant that is not providing them with utility service. Moreover, he further argues, it creates a mismatch in the rate-making process by permitting a return on

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[32] Application, Exhibit 37, Schedule B-1, at 2.

[33] Kentucky-American's Response to Commission Staff's Second Information Requests, Item 36, at 4.

[34] Public Direct Testimony of Ralph C. Smith at 13; AG's Brief at 25-26.

[35] Public Direct Testimony of Ralph C. Smith at 14.

investment in facilities that will not be in service until after the close of the test period and that will serve new customers without consideration of the revenues that will be generated from those new customers or the possible reduction in present expense levels due to these facilities.[36]

We have previously addressed and rejected these arguments.[37] In the current proceeding, the AG has not produced, nor have we discovered, any legal authority to require us to alter our earlier holding and to find that the use of a forecasted test period prohibits the inclusion of CWIP in a utility's rate base.

We question why the inclusion of CWIP is acceptable when a historic test period is employed, but is unacceptable when a forward-looking test period is used. KRS 278.192 makes no such distinction. "[T]he purpose of a forecasted test year is to reduce the regulatory lag experienced in historical test period rate cases by forecasting and matching revenue requirements and rates with the actual 12-month period for which the rates will first be placed into effect."[38] Aside from the test period used, all other rate-making principles and methodologies should remain unchanged. The AG has provided no argument or legal authority to support a contrary result.

We also find no support for the proposition that inclusion of CWIP in rate base is limited to instances where the utility's financial health is at issue. Historically, we have permitted rate base recovery of CWIP, in large measure, to prevent rate shock. For example, in Case No. 10069, we stated:

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[36] *Id.* at 15.

[37] Case No. 2004-00103, Order of Feb. 28, 2005, at 11-12.

[38] *Id.* at 12.

> Kentucky-American is currently operating in a construction mode, which will require large additions to capital. In these circumstances rate base recovery of the actual end-of period CWIP results in a series of smaller rate increases rather than awaiting completion of the projects to impose one large rate increase. This is one of the reasons the Commission has historically allowed Kentucky-American to earn a return on its CWIP investment.[39]

Clearly, CWIP is not tied merely to the financial health of the regulated utility.

Finally, we find no merit in the AG's contention that the Commission's treatment of CWIP places an unfair and unnecessary burden on ratepayers. Generally, regulated utilities recognize the carrying costs of construction in rates through one of two methods: inclusion of CWIP in rate base or accrual of Allowance for Funds Used During Construction ("AFUDC"). This Commission has, in previous Kentucky-American rate proceedings, applied a hybrid approach that combines these two methods. This approach allows Kentucky-American to include all CWIP in rate base while accruing AFUDC on projects taking longer than 30 days to complete. Under this approach, AFUDC revenue is reported "above the line." This approach eliminates the effects of including AFUDC bearing CWIP in rate base. It further allows Kentucky-American to accrue AFUDC as part of an asset's cost where appropriate and to earn a return on CWIP where AFUDC is not accrued.

Based upon the above, the Commission has decreased Kentucky-American's forecasted CWIP of $9,463,931 by $25,443 to recognize the effects of construction slippages.

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[39] Case No. 10069, Notice of Adjustment of the Rates of Kentucky-American Water Company, at 4-5 (Ky. PSC July 31, 1996).

Working Capital. Kentucky-American used a lead/lag study that employs the methodology approved in prior Kentucky-American rate proceedings to calculate cash working capital allowance. No party proposed adjustments to this methodology.[40]

In its application, Kentucky-American includes a cash working capital allowance of $2,634,000 in its forecasted rate base.[41] It subsequently reduced this amount by $493,000 to $2,141,000 to reflect the effect on cash working capital of its corrections to the forecasted operating expenses and to Annual Incentive Plan ("AIP") lag days.[42]

AG witness Smith recommends that Kentucky-American's working capital allowance be reduced by $980,000, to $1,654,000, to reflect the effects on working capital allowance of his other recommended adjustments.[43] He further recommends that the lead/lag study be updated to reflect the Commission's findings in this proceeding.[44]

After applying all reasonable and necessary adjustments to Kentucky-American's forecasted working capital calculation and correcting for the AIP lag days, the

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[40] AG witness Smith took exception to Kentucky-American's inclusion, with a zero-day payment lag, in the lead/lag study of non-cash items such as depreciation, amortization, deferred income taxes, and a return on equity. Recognizing that the Commission had accepted this practice in previous rate proceedings, he did not propose exclusion of these components. Public Direct Testimony of Ralph C. Smith at 17-18.

[41] Application, Exhibit 37, Schedule B, at 2.

[42] Base Period Update Filing, Exhibit 37, Schedule B, at 3 (filed July 15, 2010); Kentucky-American's Response to AG's Second Request for Information, Item 118.

[43] Public Direct Testimony of Ralph C. Smith at 19 and Exhibit RCS-1, Schedule B-3.

[44] *Id.* at 19.

Commission finds the appropriate working capital allowance to be $1,729,000, a decrease of $905,000 to Kentucky-American's forecasted level.

Contributions in Aid of Construction ("CIAC"). In its application, Kentucky-American includes CIAC of $48,865,890[45] as a reduction to rate base. We find that this amount should be increased by $916,100, to $49,781,990, to reflect the effects of construction slippage.[46]

Customer Advances. In its application, Kentucky-American identifies customer advances as $19,089,182.[47] The Commission finds that customer advances should be increased by $792,057, to $19,881,239, to reflect the effects of construction slippage.[48]

Deferred Maintenance. Kentucky-American incurs maintenance expenses (e.g., tank and hydrator painting and repairs, station cleaning) for which the Commission has historically allowed deferred accounting treatment. With such expenses, Kentucky-American is permitted annual recovery of allowed amortization expense. The unamortized balance of these expenses is generally included in rate base. All amounts allowed were based on actual costs from historical periods. In its application, Kentucky-American proposes the inclusion of $2,708,236 of deferred maintenance in its rate base.[49]

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[45] Application, Exhibit 37, Schedule B, at 2.

[46] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1, at 2.

[47] Application, Exhibit 37, Schedule B, at 2.

[48] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1, at 2.

[49] Application, Exhibit 37, Schedule B, at 2.

AG witness Smith proposes that Kentucky-American's deferred maintenance be reduced by 1.68 percent, or $45,500, to remove the internal labor costs.[50] In support of his recommendation, he notes that the Commission had held in Case No. 2000-120 that deferred labor expenses should not be included in a proposed acquisition adjustment[51] and that, in Kentucky-American's last rate proceeding, Kentucky-American had acknowledged that 1.68 percent of its 13-month average deferred maintenance cost balance represented deferred labor costs.

Opposing the proposed adjustment, Kentucky-American argues that AG witness Smith failed to make an independent calculation to determine if the 1.68 percent labor adjustment accurately reflects the portion of labor expense presently in deferred maintenance, but instead relied upon testimony and responses to discovery requests in a prior rate case.[52] In light of this failure and the lack of any other supporting evidence, Kentucky-American argues that Mr. Smith's testimony should be afforded little weight.

Kentucky-American further argues that the presence of a small labor component within deferred maintenance does not result in double recovery of labor expenses. Kentucky-American witness Michael Miller noted that Kentucky-American's forecasted test-year operation and maintenance labor is determined by applying an appropriate capitalization rate to total labor and labor-related benefit costs. Since the engineering

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[50] Public Direct Testimony of Ralph C. Smith at 19-20.

[51] Case No. 2000-00120, Order of May 9, 2001, at 8 (stating that "[t]o defer payroll expense between rate cases and then amortize those costs, in addition to the normal recurring payroll expense, would artificially inflate forecasted test year operations"); Public Direct Testimony of Ralph C. Smith at 20.

[52] Kentucky-American's Brief at 22.

costs charged to deferred maintenance, such as tank inspections, are embedded in the utility's capitalization rate, the utility is not recovering those costs as an expense in the forecasted test period, but is only recovering those costs through the amortization of the deferred maintenance over the life of the maintenance job.[53]

We find insufficient evidence to support the proposed adjustment. There is no evidence in the record to support the current level of labor costs within the deferred maintenance. Reliance upon a record developed almost two years ago is not sufficient. Moreover, we are not convinced that the presence of some labor expense in deferred maintenance will result in double recovery on the utility's part. Accordingly, we find that deferred maintenance of $2,708,236 should be allowed in rate base.

Deferred Taxes. In its application, Kentucky-American reduced rate base by accumulated deferred income tax of $40,026,731.[54] Included in deferred income taxes are items approved in prior rate cases: UPIS, deferred maintenance, and deferred debits.[55] Statement of Financial Accounting Standards 109 – Accounting for Income Taxes has been incorporated in the rate base deduction for income taxes and forecasted income tax expense.[56]

Accumulated deferred income taxes have been adjusted as shown in Table I to account for all adjustments made related to items affecting deferred taxes.

[53] Rebuttal Testimony of Michael A. Miller at 18-19.

[54] Application, Exhibit 37, Schedule B-6, at 2.

[55] *Id.*

[56] Direct Testimony of Sheila A. Miller at 14.

Table I: Accumulated Deferred Income Taxes		
13-Month Average Accumulated Def. Inc. Tax - Application	$	40,026,731
Slippage		(1,474)
Deferred Compensation - Summary of Revisions		24
Adj. Dep. Rates for KRS II - Summary of Adjustments		73,262
Adj. Tax Exempt Finance - Summary of Revisions	+	(188)
Accumulated deferred Income Tax Adj.	$	40,098,355

Major Tax Accounting Change. On December 31, 2008, Kentucky-American, as a member of a consolidated group of American Water Works Company ("AWWC") subsidiaries, requested authorization from the Internal Revenue Service ("IRS") to change its accounting method for recording repairs and maintenance. Instead of capitalizing repairs and maintenance costs, the members of the consolidated group sought to deduct these costs in the current tax year. In February 2010, the IRS approved the request and Kentucky-American recognized a tax deduction for costs that previously were capitalized for tax purposes.[57] Kentucky-American and the other members of the consolidated group take the position, however, that the IRS ruling fails to address a critical component of the deduction calculation and that this failure creates uncertainty regarding the lawfulness of the deduction. In light of the uncertainty, Kentucky-American asserts, Financial Accounting Standards Board Interpretation No. 48 ("FIN 48") requires the creation of a reserve for a portion of the capitalized repairs deduction to permit payment of any potential tax liability.

[57] Kentucky-American's Response to the AG's Second Request for Information, Item 85 at 20-21.

FIN 48 requires entities to identify their uncertain tax positions, evaluate each position on its merits, and determine if the IRS is likely to sustain the deduction.[58] Kentucky-American contends that it is complying with FIN 48 by establishing a liability account to record the amount of deferred taxes that the IRS would likely deny.

There are two possible outcomes for the FIN 48 account. First, the uncertainty is removed by a formal IRS audit or the expiration of the statute of limitations or a change in existing tax laws. The FIN 48 entries are then reversed and treated as cost-free capital. Alternatively, the IRS disallows the deduction and eliminates the benefit to Kentucky-American. In that event, the interest rate that the IRS will apply is 4 percent, a rate significantly below Kentucky-American's requested weighted cost of capital of 8.58 percent. Kentucky-American has agreed not to seek recovery from its ratepayers if the IRS ultimately requires any interest or penalties on the FIN 48 account provided the Commission, pending a final IRS determination, makes no adjustment for rate-making purposes to Kentucky-American's deferred taxes because of the FIN 48 account.[59]

The AG asserts that the change in accounting method has been made and that Kentucky-American is realizing a benefit–a zero-cost capital–without passing this

[58] Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes (June 2006), available at http://www.fasb.org/cs/BlobServer?blobcol=urldata&blobtable=MungoBlobs&blobkey=id&blobwhere=1175820931560&blobheader=application%2Fpdf. On July 1, 2009, the Financial Accounting Standards Board ("FASB") finalized its Accounting Standards Codification ("ASC"), creating a new system of reference for all past FASB pronouncements. Under the new codification system, FIN 48 will now be referred to as ASC Topic 740, but many practitioners continue to use the "FIN 48" nomenclature.

[59] Kentucky-American's Brief at 20.

benefit to the ratepayers.[60] He proposes two options: (1) the Commission increases Kentucky-American's accumulated deferred income taxes by the FIN 48 liability and recognizes the benefit with an interest amount for the FIN 48 reserve that is recorded above the line; or (2) Kentucky-American records the interest below the line in tandem with the creation of a regulatory asset. If the first option is employed and IRS does not disallow the deduction, Kentucky-American would make a refund to its ratepayers. If the second option is selected and the IRS disallows the deduction and assesses interest against Kentucky-American, the utility may request recovery of the interest in a future rate case proceeding.[61]

Few regulatory commissions have addressed this issue in contested proceedings. Those commissions have been reluctant to apply the rate-making treatment that the AG proposes. Finding that utilities should be encouraged to take uncertain positions with the IRS since "ratepayers and shareholders benefit when . . . [a utility] takes an uncertain tax position with the IRS, because saving money on taxes benefits the company's bottom line and reduces the amount of expense the ratepayers must pay," the Missouri Public Service Commission rejected a proposed adjustment to recognize FIN 48 liabilities as deferred income taxes.[62] The Washington Utilities and

[60] AG's Brief at 5-6.

[61] *Id.*

[62] In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service, Case No. ER-2008-0318, slip. op. at 55 (Mo. PSC Jan. 6, 2009).

Transportation Commission rejected a similar proposal and noted the risks of recognizing IRS accounting changes before all uncertainty is eliminated.[63]

We agree with the holding of those decisions and decline to adopt the AG's proposed adjustment to Kentucky-American's accumulated deferred income taxes. Kentucky-American determined that some uncertainty exists regarding the legality of the deduction related to the change in accounting methods. No party challenges the reasonableness of this determination or the appropriateness of establishing a reserve in the event of an adverse IRS ruling. Kentucky-American's action, moreover, is consistent with FIN 48. If the IRS ultimately allows the deduction or the statute of limitations expires without a challenge to the deduction, ratepayers and shareholders will benefit from the tax deferral. If the IRS disallows Kentucky-American's deduction, Kentucky-American has stated that it will not seek recovery for interest and penalties imposed by the IRS and the ratepayers will not be negatively affected.

Deferred Debits. In its application, Kentucky-American includes $1,700,474 in rate base to reflect the unamortized 13-month average of several deferred debits. Approximately $2,342 of this amount represents the unamortized acquisition adjustment related to the purchase of Boonesboro Water Association's assets. Kentucky-American has acknowledged erroneously including this unamortized acquisition adjustment twice in rate base.[64] The AG proposes to reduce deferred debits by $2,342 to correct this

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[63] Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc., Dockets UE-090704 and UG-090705, slip op. at 70 (Wash. UTC April 2, 2010).

[64] Kentucky-American's Response to Commission Staff's Second Information Request, Item 41.

error. Accordingly, the Commission finds that deferred debits should be reduced by $2,342.

Other Rate Base Elements. In its application, Kentucky-American included a reduction to rate base for "other rate base elements" in the amount of $2,349,854. Other rate base elements include contract retentions, unclaimed extension deposit refunds, accrued pensions, retirement work in progress, and deferred compensation. Kentucky-American subsequently discovered that the deferred compensation is no longer being deferred and that "other rate base elements" should be decreased by $188,379.[65] The correct amount of "other rate base elements" is $2,161,475. The Commission finds that other rate base elements should be reduced by $188,379, which results in an increase to rate base.

Based on the adjustments discussed above, the Commission has determined the company's net investment rate base to be as shown in Table II.

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[65] Rebuttal Testimony of Sheila A. Miller at 2; Kentucky-American's Response to AG's First Information Request, Item 25.

Table II: Rate Base Comparison

Rate Base Component	Kentucky-American's Proposed 13-Month Average	Commission Adjustment	Commission Approved
UPIS	$ 566,014,484	$ 3,040,339	$ 569,054,823
Utility Plant Acquisition Adj.	2,342	0	2,342
Accumulated Depreciation	(110,085,251)	67,817	(110,017,434)
Net Utility Plant in Service	$ 455,931,575	$ 3,108,156	$ 459,039,731
CWIP	9,463,931	(25,443)	9,438,488
Working Capital Allowance	2,634,000	(905,000)	1,729,000
Other Working Capital	642,421	0	642,421
CIAC	(48,865,890)	(916,100)	(49,781,990)
Customer Advances	(19,089,182)	(792,057)	(19,881,239)
Deferred Income Taxes	(40,026,731)	(71,624)	(40,098,355)
Deferred Investment Tax Cr.	(76,952)	0	(76,952)
Deferred Maintenance	2,708,236	0	2,708,236
Deferred Debits	1,700,474	(2,342)	1,698,132
Other Rate Base Elements	(2,349,854)	188,379	(2,161,475)
Net Original Cost Rate Base	$ 362,672,028	$ 583,969	$ 363,255,997

Income Statement

For the base period, Kentucky-American reports operating revenues and expenses of $67,042,231 and $53,225,929, respectively.[66] Kentucky-American proposes several adjustments to revenues and expenses to reflect the anticipated operating conditions during the forecasted period, resulting in forecasted operating revenues and expenses of $68,523,625 and $53,050,358, respectively.[67] The Commission accepts Kentucky-American's forecasted operating revenues and expenses with the following exceptions:

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[66] Application, Exhibit 37, Schedule C-2.

[67] *Id.*

AFUDC. In its application, Kentucky-American proposes to increase forecasted operating revenues by $646,180[68] to include an allowance for AFUDC. In calculating this forecast, Kentucky-American uses the weighted cost of capital requested in this proceeding of 8.58 percent.[69] To reflect the effect of slippage on CWIP, Kentucky-American adjusts AFUDC by $35,177 for an adjusted level of $629,114.[70] Kentucky-American also reduces AFUDC by $957 to reflect its correction for deferred compensation and the additional tax-exempt financing it received.

To correspond with his adjustment to eliminate CWIP from rate base, the AG proposes to reduce Kentucky-American's operating revenues by $646,180 to move AFUDC to "below-the-line" non-operating revenues. The Uniform System of Accounts for Class A and B Water Companies requires AFUDC to be recorded in non-operating revenues or "below-the-line." For rate-making purposes, the Commission allows Kentucky-American to earn a return on forecasted CWIP in rate base while offsetting the return by moving AFUDC to "above-the-line" operating revenues. This approach eliminates the effects of including the AFUDC bearing CWIP in rate base while allowing Kentucky-American to earn a return on CWIP where AFUDC is not accrued.

To be consistent with our rejection of the AG's proposal to remove CWIP from rate base, the Commission finds that operating revenues should be adjusted to reflect the inclusion of AFUDC. Using CWIP available for AFUDC and the overall rate of return of 7.74 percent, the Commission calculates a forecasted level of AFUDC of $611,003.

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[68] *Id.*, Schedule D-1, at 1.

[69] *Id.*, Schedule J-1.1/J-2.1, at 1.

[70] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, at 1.

This action, when combined with Kentucky-American's revisions, results in a decrease to Kentucky-American's forecasted operating revenues of $44,094.[71]

Labor Expense. In its application, Kentucky-American includes forecasted operations labor expense of $8,039,622. In forecasting its labor expense, Kentucky-American uses 153 full-time employees, each scheduled to work 2,088 regular hours. It also includes overtime for some employees based upon historical levels. Labor costs for the sewer operations were removed from the forecasted labor expenses.[72]

- Employee Vacancies. Kentucky-American contends that, with the use of a forecasted test period, two methods are available to address employee vacancies. First, it can project the salaries and wages based upon the assumption that all employee positions are filled. This method recognizes that, while vacancies may occur throughout the year, the job requirements associated with those vacancies continue to exist and must be met. Second, it can estimate the average number of vacancies expected to occur throughout the forecasted period and quantify the level of temporary and overtime labor that will be necessary to perform the tasks associated with the vacant position. Kentucky-American employed the first option in developing its forecasted labor expense.[73]

Proposing an adjustment to eliminate the average cost of three positions,[74] the AG takes exception to Kentucky-American's approach. He argues that some vacancies

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[71] $43,137 (Slippage) + $304 (Deferred Compensation) + $653 (Tax Exempt Financing) = $44,094.

[72] Direct Testimony of Sheila A. Miller at 6.

[73] Rebuttal Testimony of Sheila A. Miller at 6.

[74] Public Direct Testimony of Ralph C. Smith at 72-73.

should be expected at Kentucky-American throughout the year due to terminations, retirements, and changing work requirements, and affords little weight to Kentucky-American's claim that the utility has coordinated its assignment of a full-employee count with its projections of overtime and temporary employees. "[I]t does not follow," he argues, "that the items are mirror images of each other (i.e., that the dollar amounts are the same under either scenario)."[75] AG witness Smith proposed the adjustment based upon his review of Kentucky-American's historic employee vacancy rate.

The AG's proposed adjustment is similar to those that we have rejected in prior Kentucky-American rate proceedings because of its failure to "consider the vacancies' effect on Kentucky-American's overtime and temporary/contract forecasts."[76] We continue to adhere to this position. If vacant employee positions exist, work will either be shifted to other employees and thus result in an increase in overtime costs or Kentucky-American will hire additional temporary/contract labor. Kentucky-American has shown that its forecasts for overtime and temporary/contract labor have been reduced to reflect a full workforce. The vacant employee positions to which the AG refers will result in decreased direct labor costs, but that decrease will be offset by increases in overtime or temporary labor costs. Therefore, the overall impact of these vacancies on Kentucky-American's operating expenses and ultimately its revenue requirement is unknown. Accordingly, we deny the AG's proposed adjustment.

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[75] AG's Brief at 27-28.

[76] Case No. 2004-00103, Order of Feb. 28, 2005, at 44. *See also* Case No. 95-554, Order of Sep. 11, 1996, at 32 ("The AG's proposed adjustment is flawed because it did not take into consideration the total 1995 labor costs.").

• Projected Pay Increases. AG witness Smith proposes a 0.4 percent reduction in the forecasted payroll expense to compensate for the utility's alleged historic over-projection of such expenses. He contends that Kentucky-American over-projected pay increases by 0.5 percent for union employees and 0.3 percent for non-bargaining unit employees for the years 2007-2009.[77] The AG argues that the variances are significant enough to warrant some adjustment in the rate-making process, at least in regard to those employees who are not under a collective bargaining agreement.[78] Although the AG states that Kentucky-American has shown in its rebuttal evidence that the contractual increases are known and certain and that they are reliable in setting rates, he nonetheless contends that the historical evidence of over-projection warrants an adjustment to the remaining non-contractual increases.

Opposing the proposed adjustment, Kentucky-American notes that pay increases for the union employees are pursuant to an existing union contract and are therefore certain and fixed. Its current contract with union employees requires a 3 percent increase for such employees. It further notes that its forecasted payroll expense for non-union employees is based upon quantifiable salary and wage increases.[79]

Having reviewed the record, we find insufficient evidence to support the forecasted payroll expense. The existing contract between Kentucky-American and Local Union 320 of the National Conference of Firemen and Oilers ended on

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[77] Public Direct Testimony of Ralph C. Smith at 74.

[78] AG's Brief at 28.

[79] Rebuttal Testimony Sheila A. Miller at 7.

October 31, 2010.[80] The record contains no evidence that a new contract has been negotiated or the current contract extended. As Kentucky-American has asserted that projected pay increases for its salaried employees are intended to equal the projected increases to its union employees, its failure to adequately demonstrate that its contract with its union employees requires such increases casts doubt on the reasonableness of its projected increases for salaried employees. Given the lack of evidence on the certainty and reliability of the projected wage and salary increases, we find that the proposed increases should be removed from the forecasted test-period expenses. Elimination of the forecasted wage increases for all Kentucky-American employees, excluding three employees transferred to American Water Works Service Company ("Service Company"), results in a decrease to forecasted labor expense of $186,828.[81]

- Capitalization Rate. In its application, Kentucky-American uses a capitalization rate of 17.34 percent to apportion the forecasted payroll between the operation and maintenance expense account and the capital accounts. It subsequently revised this rate to 17.8 percent to reflect the transfer of three employee positions from Kentucky-American to the Service Company.[82]

Witnesses for the AG and LFUCG dispute the proposed capitalization rate. AG witness Smith proposes a capitalization rate of 19.472 percent. He contends that

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[80] Kentucky-American's Response to Commission Staff's First Request for Information, Item 20, at 2-26.

[81] Assuming arguendo that Kentucky-American had provided sufficient evidence to demonstrate the certainty of the proposed increases, the Commission has concerns regarding the reasonableness of the magnitude of the proposed increase in labor expense in light of present economic conditions, both locally and nationally.

[82] Rebuttal Testimony of Sheila A. Miller at 9.

Kentucky-American's capitalization rate has fluctuated significantly in the last five years and that Kentucky-American's budgeted capitalization rates have been below actual rates for the three-year, four-year, and five-year averages through 2009.[83] In lieu of the forecasted rate of 17.8 percent, Mr. Smith proposes the use of a capitalization rate based upon a five-year average. LFUCG witness Baudino expresses similar concerns and recommends the same adjustment.[84]

Responding to these arguments, Kentucky-American notes that the capitalization rate depends on several factors, including the construction budget, the number of water main breaks that are expensed in capital accounts, and the number of water main extensions that developers fund.[85] While conceding that the capitalization rate for the forecasted period is lower than the rate presented in its last rate case proceeding, it asserts that this change is attributable to the addition of seven new employees who will be responsible for KRS II's operation.[86] If these seven new employees devote their total time to operation and maintenance functions, Kentucky-American asserts, the percentage of operation and maintenance expense must increase and the capitalization rate correspondingly decrease.

The Commission finds that Kentucky-American's explanation is reasonable and consistent with the evidence of record and the expected operation of KRS II. While the

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[83] Public Direct Testimony of Ralph C. Smithat 69.

[84] Direct Testimony of Richard A. Baudino at 48-50.

[85] Kentucky-American Brief at 26-28.

[86] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 13(b).

use of averages may be appropriate to identify an area for further review, it is not sufficient to justify the proposed adjustment. Given the wide array of factors that affect the capitalization rate and the failure of the AG and LFUCG to provide any evidence on those factors, we find insufficient evidence to support the proposed increase in the forecasted capitalization rate and deny the proposed adjustment.

- Employee Transfer. Since the filing of Kentucky-American's application, three positions on Kentucky-American's payroll have been transferred to the Service Company's payroll.[87] These transfers reduce Kentucky-American's forecasted payroll expense by $240,001.[88] The Commission finds that an adjustment to reflect the employee transfer should be made to Kentucky-American's forecasted labor expense and, therefore, accepts Kentucky-American's proposed reduction of $240,001 to reflect the transfer of the three Kentucky-American employees to the Service Company.

- Incentive Compensation Plan ("ICP"). In its forecasted labor expense, Kentucky-American includes an expense of $349,529 related to incentive compensation.[89] The AG proposes the removal of this expense from forecasted labor expense. Noting that funding for any AIP award is based upon the utility meeting threshold targets tied to the utility's Diluted Earnings Per Share, the AG contends that the AIP's sole purpose is enhancing shareholder value and return. To the extent that the program primarily benefits shareholders, the AG argues, shareholders should bear

[87] Rebuttal Testimony of Sheila A. Miller at 4-5.

[88] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[89] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-2, at 2.

the burden of funding the program.[90] The AG further argues that Kentucky-American has failed to offer any quantitative support for its claims that AIP benefits ratepayers and, therefore, has failed to meet its burden to demonstrate the reasonableness of the expense.

Kentucky-American takes strong exception to the AG's contentions. It argues that the AIP is part of Kentucky-American's overall compensation package for its employees. AIP is intended, it asserts, to benefit customers through better service and more efficient costs. The program's incentives are directly tied to an employee's performance above the standard duties in his job description. The AIP and other incentive programs, Kentucky-American further argues, are necessary because the utility must compete for qualified employees in the markets in which it operates. The lack of such programs would limit its ability to attract and retain strongly performing employees when other surrounding businesses offer more competitive compensation packages.[91]

Kentucky-American argues that the AG has incorrectly concluded from the use of financial targets in the AIP program that the program's sole purpose is increasing stockholder value. While acknowledging that incentives are awarded only if the company meets certain financial targets, Kentucky-American asserts that targets are present only to ensure that the utility is fiscally able to award the incentive

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[90] AG's Brief at 12-13.

[91] Kentucky-American's Response to Commission Staff's Second Information Request, Item 4.

compensation.[92] To do otherwise, it argues, would be financially irresponsible. Furthermore, Kentucky-American argues, several non-financial factors, such as safety, environmental goals, customer satisfaction, business transformation, and diversity, also determine the size of the incentive compensation pool.[93] Once financial targets are met and the utility is thus deemed to be financially fit to award incentives, the incentives are awarded solely on an employee satisfying or exceeding individual performance goals pertaining to specific areas of responsibility for the employee.[94]

In prior proceedings, the Commission has refused to permit Kentucky-American's recovery of AIP costs through rates and has placed the utility on notice that "[t]he mere existence of such [incentive compensation] plans is insufficient to demonstrate that they benefit ratepayers and that their costs should be recovered through rates" and that the utility must demonstrate why shareholders should not bear the costs associated with such plans.[95]

To meet this burden, Kentucky-American produced a study that allegedly "identified and quantified the benefits that inure to ratepayers pursuant to the incentive compensation plan."[96] This study compares the cumulative increase in Kentucky-

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[92] Rebuttal Testimony of Michael A. Miller at 29-30.

[93] *Id.*

[94] *Id.* at 27.

[95] Case No. 2004-00103, Order of Feb. 28, 2005 at 49; *see also* Case No. 2000-120, Order of Nov. 27, 2000, at 44 (placing Kentucky-American "on notice that, in future rate proceedings, it must demonstrate fully why shareholders should not bear a portion of these costs").

[96] Kentucky-American's Brief at 52; Rebuttal Testimony of Michael A. Miller, Exhibit MAM-6.

American's operation and maintenance expense per customer to the cumulative increase in the Consumer Price Index ("CPI") for the five-year period from 2004 through 2009. Kentucky-American claims that its study demonstrates that, since 2005, Kentucky-American's increases in operation and maintenance costs per customer have consistently been below those of the CPI and that the utility has "successfully been able to resist cost increases more successfully than others."[97]

The study's results are inconclusive at best. For three years of the five-year period that the study considered, Kentucky-American's operations and maintenance expense on a per-customer basis increased at an annual rate that exceeded the annual increase in CPI. Kentucky-American's cumulative increase in operation and maintenance expense for the five-year period exceeded the cumulative increase in the CPI. Furthermore, the study fails to demonstrate any correlation between the rate of increase in its operation and maintenance expense per customer and its use of incentive compensation plans. It provides no comparison between its performance during the study period and that of firms that offer no incentive compensation plan to their employees. It makes no effort to eliminate or isolate the effects of other factors, such as AWWC's reorganization efforts, on Kentucky-American's operation and maintenance costs per customer.

We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders. If these goals are not met, the

[97] Kentucky-American's Brief at 52.

program is unfunded and no Kentucky-American employee receives an incentive award regardless of how well he or she meets the customer satisfaction or service quality goals. Accordingly, we find that forecasted labor expense should be decreased by an additional $349,529 to eliminate the ICP.

- Stock-Based Compensation. Kentucky-American includes stock-based compensation of $27,228 in forecasted labor expense. This compensation involves stock-based awards and grants of stock options to employees based upon the attainment of performance goals or other conditions. The purpose of Kentucky-American's stock-based compensation plan is to "encourage the participants to contribute materially to the growth of the Company, thereby benefiting the Company's stockholders, and will align the economic interest of the participant with those stockholders."[98]

Arguing that this program primarily benefits shareholders, the AG proposes the removal of this program's costs from forecasted labor expense.[99] Opposing the proposed adjustment, Kentucky-American contends that the program benefits ratepayers by increasing management personnel's investment in the company. If management views itself as a stakeholder in the company, Kentucky-American argues, it will perform to maximize the company's success by increasing efficiency, productivity, and cost containment actions that also benefit ratepayers.

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[98] Kentucky-American's Response to AG's First Request for Information, Item 15, at 25.

[99] Public Direct Testimony of Ralph C. Smith at 46-47.

The Commission finds that, based upon the stated purpose of the program, the program primarily benefits shareholders. In the absence of clear and definitive quantitative evidence demonstrating a benefit to the utility's ratepayers, the ratepayers should not be required to bear the program's costs. Accordingly, we find that forecasted labor expense should be decreased by $27,288 to eliminate the stock-based compensation plan.

Fuel and Power. In its forecasted operations, Kentucky-American includes fuel and power expense of $4,375,584. It used an unaccounted-for water loss percentage of 14 percent to forecast pumpage.[100] Kentucky-American's present unaccounted-for water loss is 11.8 percent.[101] Using this percentage, Kentucky-American calculated a revised fuel and power expense of $4,297,587, which is $77,997 below its original forecast.[102] Accordingly, the Commission finds that Kentucky-American's forecasted fuel and power expense should be decreased by $77,997.

Chemicals. In its forecasted operations, Kentucky-American included chemical expense of $1,772,730. As with its forecasted fuel and power expense, Kentucky-American used an unaccounted-for water loss of 14 percent to forecast chemical

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[100] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-2, at 18.

[101] VR: 8/10/10; 15:45:45 -15:46:05. The present level represents a significant achievement for Kentucky-American. For the three-year period from January 1, 2006 through December 31, 2008, Kentucky-American's average line loss was 13.51 percent. For the year ending December 31, 2006, Kentucky-American experienced a line loss of approximately 14.94 percent. The Commission applauds Kentucky-American's efforts in this area.

[102] Kentucky-American's Response to Hearing Data Requests, Item 7, at 1.

expense.[103] Using the current water-loss percentage of 11.8 percent, Kentucky-American calculated a revised chemical expense of $1,729,077, which is $43,653 below its original estimate.[104] Accordingly, the Commission finds that Kentucky-American's forecasted chemical expense should be decreased by $43,653.

Waste Disposal. In its forecasted operations, Kentucky-American includes waste disposal expense of $340,226. This expense includes the amortization of the forecasted cost of $245,000 over a 24-month period, or $122,500, for the cleaning of Kentucky River Station I's lagoon in June 2011.[105] Kentucky-American developed its forecasted cost by averaging the three lowest bids received for lagoon cleaning in 2009.[106]

The AG offers two alternative methods to the forecasted expense. AG witness Smith argues that the most appropriate means to forecast the expense is to average the actual costs of the four lagoon cleanings that have occurred since 2001. He proposes an annual cost of $90,000, which is the average cost of the last four lagoon cleanings, amortized over 24 months.[107] The AG also suggests that this expense be based upon the lowest bid that Kentucky-American received for lagoon cleaning conducted in

[103] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-3.

[104] Kentucky-American's Response to Hearing Data Requests, Item 7, at 1.

[105] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-4.

[106] Rebuttal Testimony of Keith Cartier at 2.

[107] Public Direct Testimony of Ralph C. Smith at 76-77.

2009.[108] This methodology produces the same result as AG witness Smith recommends.

Noting that AG witness Smith's methodology requires the use of dated and potentially inaccurate information, Kentucky-American opposes the proposed adjustment. Kentucky-American witness Cartier testified that lagoon cleaning occurs approximately every three years. Relying on the average cost of the four prior lagoon cleanings as the AG recommends requires reliance on some cost information that is at least twelve years old and that does not consider the effects of inflation or changing market conditions.[109]

The Commission finds that Kentucky-American's methodology for forecasting lagoon cleaning expense is reasonable and further finds that the AG's proposed methodology, as it fails to consider the effects of inflation and relies upon dated information, is inappropriate. Accordingly, we decline to accept the AG's proposed adjustment to Kentucky-American's forecasted waste disposal expense.

Management Fees. Kentucky-American has included management fee expense of $9,028,121 in its forecasted operations.

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[108] AG's Brief at 28.

[109] Rebuttal Testimony of Keith Cartier at 1-2.

• Revised Service Company Budget. The AG proposes to decrease forecasted management fees by $133,865 to reflect adjustments in the Service Company's budget.[110] Kentucky-American does not contest the proposed adjustment.[111] Kentucky-American informed the Commission that its forecasted management fee should be reduced by $133,865 to reflect a revision to the Service Company budget that had been finalized after the application in this proceeding had been filed. Accordingly, the Commission has decreased Kentucky-American's forecasted management fee by $133,865 to reflect the updated actuarial information.

• ICP and Stock-based Compensation. Included in Kentucky-American's management fee forecast is incentive compensation of $436,987 and stock-based compensation of $179,208. For reasons previously stated,[112] the Commission finds that Kentucky-American's forecasted management fee should be decreased by $616,195 to eliminate the ICP and stock-based compensation plan.

• Donations and Miscellaneous Expenses. The AG proposes a reduction of $65,793 in management fees to eliminate charitable contributions, advertising, dues and other miscellaneous expenses.[113]

Kentucky-American opposes the proposed adjustment as it relates to advertising expenses, membership dues, and employee meals. As to the proposed removal of

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[110] Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-6.

[111] Rebuttal Testimony of Michael A. Miller at 47-48.

[112] *See supra* text accompanying notes 89-99.

[113] Public Direct Testimony of Ralph C. Smith at 56-58; Exhibit RCS-1, Schedule C-8.

advertising expenses of $11,909, Kentucky-American witness Michael Miller testified that these expenses consisted primarily of job placement ads and are related to recruitment and hiring efforts to maintain adequate personnel staffing.[114] As to the membership fees of $23,961,[115] which include memberships for Service Company employees in the American Bar Association, American Water Works Association, Kentucky Bar Association, and American Institute of Certified Public Accountants, Kentucky-American asserts that the memberships are necessary to ensure professional certification for the Service Company employees and to ensure these employees have access to valuable and pertinent information in their respective fields and the water industry and, therefore, benefit ratepayers.[116] Finally, Kentucky-American notes that it and the Service Company have policies prohibiting reimbursement for any meals except those having a legitimate business purpose and the meals in question complied with those policies.

The Commission finds that the expenses at issue that are related to advertising expenses, membership dues, and employee meals should not be disallowed or excluded. The record contains substantial evidence that each is for legitimate purposes. The AG has presented no evidence to support a contrary finding. We find the advertising expenses in question relate to a legitimate business function and provide a material benefit to Kentucky-American customers. We further find that recovery of

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[114] Rebuttal Testimony of Michael A. Miller at 53.

[115] For a list of these organizations, see Kentucky-American's Response to AG's First Request for Information, Item 1a.

[116] *Id.*

fees related to an employee's membership in a professional organization is generally appropriate and beneficial to ratepayers in those instances in which the employee's membership is required to comply with professional licensing requirements or provides the employee access to technical training and assistance in specialized areas involving utility management or operations.

As to the other items that the AG has identified, the Commission finds those expenses are not appropriately borne by ratepayers and that Kentucky-American's forecasted management fee should be decreased by $9,735[117] to reflect their removal.

- Business Development. In its forecasted management fee, Kentucky-American includes business development costs of $223,380 that the Service Company has allocated to Kentucky-American. Of this amount, the Commission has deducted $23,834 to reflect the elimination of costs related to AIP or stock-based compensation.[118]

AG witness Smith proposes a further reduction of business development costs of $198,342. He contends that these expenses are "unnecessary for the provision of safe, reliable and reasonably priced water and wastewater utility service in Kentucky."[119] In his brief, the AG argues that business development advances the interest of shareholders and that such activity contains no assurance or certainty of benefits for Kentucky-American ratepayers. Until Kentucky-American has demonstrated a clear

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[117] $4,728 (Charitable Contributions) + $3,499 (Community Relations) + $1,427 (Company Dues Membership) + $81 (Penalties) = $9,735.

[118] *See supra* text accompanying notes 86-96; Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-7.

[119] Public Direct Testimony of Ralph C. Smith at 56.

benefit to ratepayers, he further argues, these costs should not be assigned to ratepayers.

Opposing the proposed adjustment, Kentucky-American contends the proposal is unsupported and contrary to the existing evidence. It notes that AG witness Smith made no effort to determine what comprises business developments costs and has not performed an independent analysis to determine if the ratepayers benefited from those activities.[120] It further contends that Kentucky-American's existing customers benefit from the revenue growth produced from development activities and from efficiency gains, cost-saving measures and growth that acquisitions spur. It noted that Kentucky-American's recent contract to perform billing services for LFUCG will provide $364,000 in annual revenues and will benefit ratepayers by reducing Kentucky-American's revenue requirement.[121]

The Commission has previously placed Kentucky-American on notice that business development expenses allocated to the utility from the Service Company would be considered reasonable and appropriate for rate recovery only in those instances in which the utility was able to "appropriately document and separate forecasted management fees between those that are directly assignable and those that are allocated."[122] In the present proceeding, the Commission sought a detailed listing and description of business development costs included in forecasted management

[120] Rebuttal Testimony of Michael A. Miller at 51.

[121] *Id.* at 51-52.

[122] Case No. 2004-00103, Order of Feb. 28, 2005, at 53. Placing this burden upon Kentucky-American is consistent with Kentucky-American's statutory duty as an applicant to demonstrate that its proposed rates are reasonable. *See* KRS 278.190(2).

fees. Kentucky-American provided a breakdown of the business development costs by object account but could not describe the business development services that would be provided for each identified cost.[123]

In light of its failure to identify or describe the business development services that the Service Company provides, we find that Kentucky-American has failed to meet its burden to demonstrate the reasonableness of the business development expenses and that the AG's proposed adjustment to reduce forecasted management fees by $198,342 should be accepted.

- Employee Transfer. To reflect the transfer of three employees from Kentucky-American to the Service Company, Kentucky-American proposes to increase management fees by $370,765.[124] The Commission finds that Kentucky-American's forecasted management fee should be increased by $370,765 to reflect the transfer of three Kentucky-American employees to the Service Company.

- Labor Costs. LFUCG witness Baudino proposes a reduction of $2,146,000 in management fee expense to eliminate the labor allocations that Kentucky-American has failed to show were prudently incurred. He testified that Kentucky-American's application indicates that the Service Company labor costs are greater than if no reorganization or restructuring of Kentucky-American and the Service

[123] Kentucky-American's Response to Commission Staff's Second Information Request, Item 20(c).

[124] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

Company had occurred and that none of the stated benefits of the restructuring justify the greater level of costs.[125]

The Commission finds that LFUCG has not provided sufficient evidence to support the proposed adjustment. In his testimony, Mr. Baudino provides little justification or factual evidence to support his position. Moreover, he ignores the previously filed testimony of Kentucky-American witness Baryenbruch, who testified extensively on the benefits that the Service Company provides to Kentucky-American and who concluded that Kentucky-American's arrangement with the Service Company resulted in a savings of $1.5 million to Kentucky-American and its ratepayers. In light of the absence of any attempt to contradict or rebut Mr. Baryenbruch's findings, we afford little weight to Mr. Baudino's testimony on this issue and decline to make the proposed adjustment.

Group Insurance. Kentucky-American included in its forecasted operations group insurance expense of $2,313,543.[126] The forecasted expense is comprised of group insurance costs for the current associates and post-retirement employee benefit costs ("OPEB") for Kentucky-American's current and retired employees. Kentucky-American based OPEB expense upon the projections of the actuarial firm of Towers Watson. The current group insurance costs reflect the use of Kentucky-American's current group insurance premium statement rates in effect as of January 1, 2010.[127] After filing its application, Kentucky-American proposed to decrease forecasted group

[125] Direct Testimony of Richard A. Baudino at 44-46.

[126] Application, Exhibit 37, Schedule C-2.

[127] Direct Testimony of Sheila A. Miller at 5-6.

insurance by $52,206[128] to reflect the latest Towers Watson actuarial projections for the forecasted test year[129] and by an additional $47,202[130] to reflect the transfer of three employees to the Service Company.[131] Group insurance expense has been decreased by an additional $65,247 to reflect the elimination of projected employee wage increases. The Commission finds that these proposed adjustments are reasonable and that Kentucky-American's forecasted group insurance expense should be decreased by $164,835.

Pension. Kentucky-American includes pension expense of $1,267,732 in its forecasted operations.[132] Towers Watson's projected pension costs are allocated to each of AWWC's subsidiaries based upon the ratio of valuation earnings for that company to total valuation earnings for AWWC.[133] After filing its application, Kentucky-American proposed to decrease forecasted pension expense by $253,262 to reflect

[128] Kentucky-American's Response to Commission Staff's Second Information Request, Item 23.

[129] Rebuttal Testimony of Michael A. Miller at 38; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 23; Kentucky-American's Response to AG's Second Request for Information, Item 67(e).

[130] $42,300 (Group Insurance) + $3,995 (401(k) + $846 (DCP) + $61 (Retiree Medical) = $47,202.

[131] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[132] Direct Testimony of Michael A. Miller at 28.

[133] KAWC's Response to Commission Staff's First Information Request, Item 1(a) Workpaper WP3-7, at 3.

Towers Watson's most recent projections[134] and by an additional $56,027 to reflect the transfer of the three employees to the Service Company.[135] Pension expense has been decreased by an additional $29,407 to reflect the elimination of the employee wage increases. The Commission finds that these proposed adjustments are reasonable and that Kentucky-American's forecasted pension expense should be decreased by $340,751.

Regulatory Expense. Kentucky-American includes regulatory expense of $366,462 in its forecasted operations.[136] This forecasted expense includes the cost of its depreciation study, amortized over a five-year period; the preparation and litigation costs of the present case,[137] amortized over a three-year period; and the amortized rate case expenses associated with its previous two rate cases. Since filing its application, Kentucky-American has proposed to adjust the forecasted level to $391,328 to correct its failure to include the final two months of amortization of rate case expenses for Case No. 2007-00143.[138] Following the evidentiary hearing in this matter, Kentucky-American

[134] Rebuttal Testimony of Michael A. Miller at 38; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 23.

[135] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[136] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 3-8, at 1; Rebuttal Testimony of Michael A. Miller at 38-39.

[137] Kentucky-American originally projected the level of this expense at $590,000. Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 3-8, at 2.

[138] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT); Kentucky-American's Response to AG's Second Request for Information, Item 69(e).

revised its forecast of preparation and litigation costs of the present case to $553,121, which is $36,879 below its original projection.[139]

The AG objects to the inclusion of all rate case expenses associated with Cases No. 2007-00143 and No. 2008-00426. He notes that in neither proceeding did the Commission make a finding regarding the reasonableness of these expenses, expressly authorize their recovery through general rates, or authorize Kentucky-American to record the costs as regulatory assets. Furthermore, the AG contends, as both cases involved settlement agreements which were silent on the recovery of rate case expenses, Kentucky-American's current efforts to recover the rate case expenses constitute an attempt to unilaterally amend the settlement agreements in those proceedings.[140]

Responding to the AG's objection, Kentucky-American argues that longstanding Commission precedent supports the practice of amortizing over a three-year period reasonably incurred rate case expenses.[141] It has provided evidence that the expenses in question were incurred in the course of preparing for and litigating rate case proceedings. It further notes that the AG has presented no evidence in this proceeding to suggest that the expenses in question were not incurred or were unreasonable. While the issues in Cases No. 2007-00147 and No. 2008-00426 were resolved by settlement agreements that were silent on the issue of rate case expenses, Kentucky-American notes, no party in those proceedings contested Kentucky-American's

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[139] Kentucky-American's Response to Hearing Data Requests, Item 20.

[140] AG's Brief at 15-16; Public Direct Testimony of Ralph C. Smith at 60-61.

[141] Kentucky-American's Brief at 36 & n.49.

recovery of rate case expenses through general rates. It is unreasonable, Kentucky-American asserts, that shareholders should bear the full cost of these rate cases because those cases ended in agreement.[142]

It is a well-settled principle of utility law that rate case expenses "must be included among the costs of operation in the computation of a fair return."[143] Kentucky-American, however, has presented no evidence to demonstrate that the rates agreed to and approved in Cases No. 2007-00147 and No. 2008-00426 failed to include rate case expense. As the settlement agreement in each proceeding is silent on this issue, we cannot assume that parties agreed to the amortization of rate case expense any more than we can assume that parties did not establish rates providing for the immediate expensing of the full rate case expense. Accordingly, we find that the AG's proposed adjustment should be accepted.

Any utility that enters a settlement agreement in a rate case proceeding and wishes to amortize the rate case expense incurred in that proceeding should ensure that the settlement agreement specifically addresses the issue of rate case expenses <u>or</u> request the creation of a regulatory asset for its rate case expenses for accounting purposes. Such practice is consistent with our prior holdings that the establishment of a regulatory asset for accounting purposes is a pre-condition for rate recovery in a later

[142] Rebuttal Testimony of Michael A. Miller at 43.

[143] *West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63, 74 (1935).

rate case proceeding and that the Commission's prior approval is necessary before the establishment of a regulatory asset.[144]

The AG further proposes a 30.4 percent reduction of Kentucky-American's forecasted rate case expense amortization amount for the current case. He asserts that Kentucky-American has consistently overstated its forecasted rate case expenses. He proposes to normalize the current estimated rate case expense using the ratio of actual costs to projected costs from Kentucky-American's last two general rate case proceedings.[145]

For several reasons, we find no merit in this proposal. First, the Commission has historically used actual costs to determine rate case expense, even in proceedings in which a forward-looking test period is used. This practice ensures greater accuracy than the normalization method that the AG proposes. Second, the rate case proceedings which the AG uses to develop his normalization ratio ended with settlement agreements and truncated hearings. Those proceedings generally do not require extensive hearing preparation or the preparation of written briefs and hence the level of expense incurred in them is generally much less than fully contested rate case proceedings. Third, normalization implicitly assumes that all rate cases are roughly equivalent. In practice, the number and complexity of issues, the intensity of discovery, and the number of parties in a proceeding, all factors affecting rate case expense, may significantly vary. Fourth, as normalization generally involves an average of historical

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[144] *See, e.g.*, Case No. 2003-00426, Application of Louisville Gas and Electric Company for an Order Approving an Accounting Adjustment to Be Included in Earnings Sharing Mechanism Calculations for 2003, at 4 (Ky. PSC Dec. 23, 2003).

[145] Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-11.

costs, it will not reflect inflationary increases in the legal, accounting and other costs that are incurred in preparing and litigating a rate case proceeding.

The AG has further proposed that we abandon our long-standing practice of amortizing rate case expense and, instead, normalize that expense. Through normalization, Kentucky-American would be entitled to recover not the historical amount of the expenditure but a future amount that the Commission deems reasonable. Much like amortized historical amounts, the normalized costs would be divided by their estimated useful lives to determine the annual expense to be recovered through rates.

The AG asserts that the normalization approach would eliminate the unamortized account balances since those accounts would no longer be recorded on Kentucky-American's books. He asserts that "the purpose of the rate case allowance should be to include in rates a representative and normal annual level of reasonably and prudently incurred regulatory expense, rather than to provide the utility with a single-issue focus and what could otherwise become a guaranteed dollar-for-dollar recovery for this cost."[146]

The AG's arguments closely resemble those that he presented in Case No. 2004-00103. For the same reasons set forth in our decision in that proceeding, we decline to follow the AG's suggested course of action.[147] Based upon our review of the record, we find that forecasted regulatory expense should be decreased by $148,128, from $391,328 to $243,200, to reflect the elimination of amortized rate case expense

[146] *Id.* at 66.

[147] Case No. 2004-00103, Order of Feb. 28, 2005, at 20.

from Cases No. 2007-00143[148] and No. 2008-00426, and the reduction of $12,293 of amortized rate case expense related to the current proceeding.[149]

Insurance Other Than Group. Kentucky-American includes in its forecasted operations insurance other than group expense of $742,262.[150] This forecast reflects the current annual premiums for the following insurance coverages: general liability; property liability; fiduciary liability; commercial crime coverage; flood liability; and worker's compensation. Kentucky-American proposed to reduce its forecast by $47,931 to reflect the 2010 insurance premiums and by an additional $804 to reflect the transfer of three Kentucky-American employees to the Service Company.[151] The Commission finds that the proposed adjustments are reasonable and that forecasted insurance other than group expense should be decreased by $48,735.

Customer Accounting. Kentucky-American includes customer accounting expense of $1,712,517 in its forecasted operations.[152] This expense includes, but is not

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[148] The only cost included from Case No. 2007-00143 is $6,000 for the 2007 depreciation study.

[149] $590,000 (original forecast) - $553,121 (revised forecast) = $36,879.
$36,879 ÷ 3-years = $12,293 (reduction in amortized rate case expenses).

[150] Application, Exhibit 37, Schedule C-2; Direct Testimony of Sheila A. Miller at 7.

[151] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT); Rebuttal Testimony of Sheila A. Miller at 4; Base Period Update Filing, Exhibit 37, Schedule D-2.3 (filed July 15, 2010).

[152] Direct Testimony of Sheila A. Miller at 7; Application, Exhibit 37, Schedule C-2.

limited to the following: postage; telephone; forms for customer service and billing; uncollectible accounts; and collection agencies.[153]

The AG proposes to reduce uncollectible accounts by $27,580.[154] He notes that Kentucky-American did not use budget information to develop its forecasted uncollectible expense, but instead developed an "Uncollectibles Factor" based upon the ratio of its 2009 uncollectible expense to its billed revenue and then applied this factor to pro forma revenues for the forecasted test year.[155] This factor is significantly higher than the Uncollectible Factor for most recent years. As the "Uncollectibles Factor" fluctuates, AG witness Smith argues, it is more appropriate to use a three-year average rather than place undue reliance upon any one year.[156]

Kentucky-American did not directly respond to AG witness Smith's proposed adjustment. In a response to a discovery request, however, it stated that its "experience for 2009 was the best indicator of the uncollectible expense likely to be present in the forecasted test-year in this case, given the current and expected economic conditions during the forecasted test-year."[157] In his rebuttal testimony, Kentucky-American

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[153] Direct Testimony of Sheila A. Miller at 7.

[154] Direct Testimony of Ralph C. Smith at 80.

[155] *Id.* at 78-79.

[156] *Id.*

[157] Kentucky-American's Response to Commission Staff's Third Request for Information, Item 7.

witness Michael Miller noted that the AG's proposal was an acceptable method of rate-making.[158]

Based upon our review of the evidence, we find that Kentucky-American has failed to demonstrate that its proposed method of forecasting uncollectible accounts is reasonable and that the AG's proposed methodology is reasonable and more appropriate in this case. Accordingly, we accept the AG's adjustment to reduce Kentucky-American's forecasted customer accounting expense by $27,589 to reflect the average uncollectible rate of 0.741 percent.

Miscellaneous Expense. Kentucky-American includes general office expense of $3,440,139 in forecasted operations.[159] This expense includes, but is not limited to the following: dues and memberships; employee travel and meal expenses; office supplies; and general office utility costs.[160] Kentucky-American includes the following in this expense: $14,420 for an employee recognition banquet; $5,150 for a United Way rally; and $5,500 for a holiday event.[161]

The AG proposes to reduce miscellaneous expense by $25,070 to remove the three specific expenses listed above.[162] He contends that none of the expenses are

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158 Rebuttal Testimony of Michael A. Miller at 33 ("As Mr. Smith suggests regarding uncollectible expense, you can use an average, or adjust based on historical actual to budget much like the Commission historically treats forecasted test-year capital spending.").

159 Application, Exhibit 37, Schedule C-2; Direct Testimony of Sheila A. Miller at 8.

160 Direct Testimony of Sheila A. Miller at 8.

161 Application, Exhibit 37, Schedule F-2.3.

162 Public Direct Testimony of Ralph C. Smith at 71.

necessary to provide safe, adequate and proper utility service and are more properly borne by utility shareholders.

Contending that the expenses are appropriate and benefit utility customers, Kentucky-American opposes the proposed reduction. It asserts that its employee recognition banquet is an appropriate means of recognizing employees' contributions and enhances customer service and satisfaction by promoting a cohesive and motivated work force. The United Way, it argues, promotes employee participation and contribution in an important community program that directly benefits many of the company's customers.[163]

In prior rate case proceedings, the Commission has found that the costs related to employee recognition banquets and gifts should not be borne by utility ratepayers.[164] As to the United Way function, while the community and thus Kentucky-American's customers indirectly receive some benefit from the function, the expense is a form of charitable contribution which the Commission has generally found should be borne by utility shareholders.[165] Accordingly, we accept the AG's proposed adjustment.

Depreciation. Kentucky-American includes depreciation expense of $11,086,076 in its forecasted operations.[166] Based on the Commission's treatment of forecasted rate base with regard to slippage and the effect of revisions to Kentucky-American's

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[163] Rebuttal Testimony of Michael A. Miller at 72.

[164] *See, e.g.*, Case No. 97-034, Order of Sep. 30, 1997, at 40; Case No. 95-554, Order of Sep. 11, 1996, at 43.

[165] *See, e.g.*, Case No. 95-554, Order of Sep. 11, 1996, at 43.

[166] Application, Exhibit 37, Schedule I-1; Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 4-1, at 9.

depreciation study, an adjustment has been made to decrease forecasted depreciation expense by $201,593.[167]

General Taxes. Kentucky-American includes a forecast of general tax expense of $5,160,307, which includes property taxes and payroll taxes of $4,419,174 and $621,307. Based on our treatment of forecasted rate base with regard to slippage, we have increased forecasted property taxes expense by $15,539. We have also reduced payroll taxes by $63,473 to reflect the effects of our removal of the costs of incentive pay plans, the elimination of the employee wage increases, and the transfer of three Kentucky-American employees to the Service Company.

Income Taxes. Kentucky-American includes a forecast of current income tax expense of $1,066,982 in test-period operations. Adjusting Kentucky-American's income tax forecast, the Commission arrives at its current income tax expense of $23,182 as shown in Table III.

[167] $60,553 (Slippage Adjustment) + ($262,146) (Depreciation Study Revision) = ($201,593).

Table III: Current Income Tax				
	Adjustments	Income Taxes		
	Revenue/ Expense	State 6.0000%	Federal 35.0000%	Total
KAWC's Forecasted Taxes		$ (164,573)	$ (902,409)	$(1,066,982)
AFUDC	$ (44,094)	(2,646)	(14,507)	(17,153)
Labor	$ (803,586)	48,215	264,380	312,595
Fuel & Power - 11.8% Line Loss	$ (77,997)	4,680	25,661	30,341
Chemicals - 11.8% Line Loss	$ (43,653)	2,619	14,362	16,981
Management Fees	$ (587,372)	35,242	193,246	228,488
Group Insurance	$ (164,835)	9,890	54,231	64,121
Pensions	$ (340,751)	20,445	112,107	132,552
Regulatory Expense	$ (160,421)	9,625	52,779	62,404
Insurance Other than Group	$ (48,735)	2,924	16,034	18,958
Customer Accounting	$ (27,589)	1,655	9,077	10,732
Miscellaneous	$ (25,070)	1,504	8,248	9,752
Depreciation - Slippage	$ (201,593)	12,096	66,324	78,420
Property & Capital Stock	$ 15,539	(932)	(5,112)	(6,044)
Payroll	$ (63,473)	3,808	20,883	24,691
Interest Synchronization	$ (89,181)	5,351	29,341	34,692
Book Depreciation	$ (60,553)	3,633	19,922	23,555
Tax Depreciation	$ 138,010	(8,281)	(45,405)	(53,686)
Taxable Customer Advances & CIAC	$ (263,660)	15,820	86,744	102,564
Tax AFUDC	$ (41,651)	2,499	13,703	16,202
		$ 3,574	$ 19,609	$ 23,183

Consolidated Income Tax Adjustment. The AG proposes that Kentucky-American's forecasted current and deferred income tax expenses be adjusted to reflect the use of a consolidated tax return. He notes that Kentucky-American calculates federal income taxes on a stand-alone basis.[168] Kentucky-American, however, is part of a consolidated group, which AWWC owns, that files a combined federal income tax return to take advantage of the tax losses experienced by some of the group's members.[169] The use of a consolidated tax filing, the AG states, permits the tax loss benefits generated by one group of subsidiaries to be shared by the other consolidated

[168] AG's Brief at 7; Public Direct Testimony of Ralph C. Smith at 29.

[169] Public Direct Testimony of Ralph C. Smith at 29-30.

group members, thus resulting in a reduced effective federal income tax rate. The AG proposes that these tax benefits should be flowed to Kentucky-American's ratepayers to reflect the actual taxes paid rather than calculate the amount of taxes based upon stand-alone methodology. To do otherwise, he argues, would overstate Kentucky-American's federal income tax. Regulatory commissions in three other jurisdictions in which AWWC affiliates are located have adopted consolidated tax adjustments for rate-making purposes.[170] Use of the AG's consolidated tax adjustment results in a decrease of $1,361,624 to Kentucky-American's forecasted income tax expense.[171]

The AG's proposed adjustment relies heavily upon our decision in Case No. 2004-00103 in which we found the use of a consolidated tax adjustment was warranted and appropriate in view of representations that Kentucky-American, AWWC and RWE Aktiengesellschaft ("RWE") had made in an earlier proceeding[172] to secure Commission approval of RWE's acquisition of control of Kentucky-American and the conditions that we had imposed as part of our approval. We stated in that decision:

> In that proceeding [Case No. 2002-00317], Kentucky-American and others sought approval of the transaction that enabled RWE's acquisition of control of Kentucky-American. One feature of this transaction was the creation of TWUS [Thames Water Aqua US Holdings, Inc.], an intermediate holding company that would hold the stock of American

[170] These jurisdictions are Pennsylvania, New Jersey, and West Virginia. Oregon and Texas also impose a consolidated tax adjustment. Rebuttal Testimony of James I. Warren at 24.

[171] Public Direct Testimony of Ralph C. Smith, Schedule C-2.

[172] Case No. 2002-00317, The Joint Petition of Kentucky-American Water Company, Thames Water Aqua Holdings GmbH, RWE Aktiensgeselschaft, Thames Water Aqua US Holdings, Inc., Apollo Acquisition Company and American Water Works Company, Inc. for Approval of a Change of Control of Kentucky-American Water Company (Ky. PSC Dec. 20, 2002).

> Water and all of Thames Water Aqua Holdings GmbH's other U.S. affiliates. Kentucky-American asserted the creation of TWUS would permit the filing of consolidated U.S. tax returns. The ability to file such a tax return, Kentucky-American argued, benefited the public because it would reduce administrative expenses by eliminating the need to file multiple tax returns and permit some tax savings by allowing payment of taxes calculated on the net profits of all entities within the consolidated group.
>
> We note that when approving the proposed transaction, we rejected specific proposals to condition our approval on the Joint Petitioners treating any tax savings achieved through the write-off of losses incurred in unregulated U.S. operations against regulated U.S. earnings as a benefit of the transaction and sharing that benefit with Kentucky-American ratepayers. We took that action, not because the proposals were without merit, but because we had previously directed that a portion of any merger savings be allocated to Kentucky-American ratepayers and that additional conditions were unnecessary. Kentucky-American did not take exception to or protest our reasoning.
>
> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation.[173]

RWE's recent divestiture of AWWC, however, significantly limits the application of the holding in Case No. 2004-00103. In approving the proposed divestiture, the Commission expressly declared that all terms and conditions imposed as part of our

[173] Case No. 2004-00103, Order of Feb. 28, 2005, at 64-66. In the current proceeding, Kentucky-American argues that the Commission misunderstood and misinterpreted RWE and AWWC's representations regarding potential tax savings related to the transaction before us in Case No. 2002-00317. Our review of the record of Case No. 2002-00317 indicates considerable merit to Kentucky-American's position.

approval of RWE's acquisition of control of Kentucky-American would terminate upon RWE's complete divestiture of its interests in AWWC.[174] That divestiture occurred on November 30, 2009.[175] To the extent that the Commission has based the use of a consolidated tax adjustment on the premise that any savings resulting from the TWUS's use of a consolidated tax return was a benefit of the RWE acquisition and should be shared with ratepayers, the RWE divestiture renders that premise invalid.

Except for Case No. 2004-00103, which involves unique circumstances, the Commission has consistently rejected proposals to apply a consolidated tax adjustment and treated utilities on a stand-alone basis.[176] We have found that use of such an adjustment would result in the subsidization of ratepayers by the utility's non-regulated operations. Moreover, many utility regulatory commissions appear to disfavor

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[174] Case No. 2006-00197, The Joint Petition of Kentucky-American Water Company, Thames Water Aqua Holdings GmbH, RWE Aktiengesellschaft, Thames Water Aqua U.S. Holdings, Inc., and American Water Works Company, Inc. for Approval of a Change In Control of Kentucky-American Water Company, at 36 (Ky. PSC April 16, 2007).

[175] *See* Case No. 2009-00359, Kentucky-American Water Company's Application for Approval of Payment of Dividend for Third Quarter of Calendar Year 2008 (Ky. PSC Dec. 28, 2009).

[176] *See, e.g.*, Case No. 2009-00549, Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Rates (Ky. PSC July 30, 2010); Case No. 2009-00548, Application of Kentucky Utilities Company for an Adjustment of Electric Rates (Ky. PSC July 30, 2010); Case No. 2003-00434, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company (Ky. PSC June 30, 2004); Case No. 2009-00548, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Kentucky Utilities Company (Ky. PSC June 30, 2004).

the use of consolidated tax adjustments.[177] In light of the RWE divestiture and the absence of any compelling argument to jettison the "stand-alone" rate-making principle, we find that the AG's proposed income tax consolidation adjustment should be denied.

Deferred Income Taxes. Kentucky-American includes a forecast of deferred income tax expense of $2,177,869 in test-period operations. Adjusting Kentucky-American's income tax forecast for slippage, the tax-exempt financing, and the revision of the depreciation study, the Commission arrives at a deferred income tax expense of $2,328,717.

Based on the accepted adjustments to forecasted revenues and expenses, the Commission finds Kentucky-American's forecasted net operating income at present rates to be $16,441,382 as shown in Table IV.

Table IV: Income Statement Comparison

Account Titles	Kentucky-American Forecasted Revenues & Expenses	Recommended Adjustments	Forecasted Revenues & Expenses
OPERATING REVENUES			
Water Sales	$ 64,753,488	$ -	$ 64,753,488
Other Operating Revenues	3,770,137	(44,094)	3,726,043
Operating Revenues	$ 68,523,625	$ (44,094)	$ 68,479,531
OPERATING EXPENSES			
Operation & Maintenance Exp.	$ 35,459,367	$ (2,280,009)	$ 33,179,358
Depreciation & Amortization	11,319,797	(201,593)	11,118,204
General Taxes	5,160,307	(47,934)	5,112,373
Income Tax Expense	1,110,887	1,241,012	2,351,899
Total Operating Expenses	$ 53,050,358	$ (1,288,524)	$ 51,761,834
Net Operating Income	$ 15,473,267	$ 1,244,430	$ 16,717,697

[177] *See, e.g., Re SourceGas Distribution LLC*, 280 PUR 4th 226 (Neb. PSC Mar. 9, 2010); *Re Delmarva Power and Light Company*, 278 PUR4th 419 (Md. PSC Dec. 30, 2009); *Washington Utilities and Transportation Commission v. PacifiCorp dba Pacific Power & Light Co.*, 257 PUR4th 380 (Wash. UTC June 21, 2007); *Northern States Power Company dba Xcel Energy*, 253 PUR4th 40 (Minn. PUC Sep. 1, 2006); *Re Ohio Bell Telephone Company*, 8 PUR3d 136 (Ohio PUC Dec. 30, 1954).

Rate of Return

Capital Structure. Kentucky-American's proposed capital structure based on the projected 13-month average balances for the forecasted test period and the costs assigned to each capital component is shown in Table V.

TABLE V		
Components	Kentucky-American's Capitalization	Assigned Costs
Short-Term Debt	2.315%	2.085%
Long-Term Debt	52.060%	6.410%
Preferred Stock	1.652%	7.750%
Common Equity	+ 43.973%	11.500%
Total Capitalization	100.000%	

Although the AG states that he is employing Kentucky-American's proposed capital structure in developing his recommended weighted cost-of-capital,[178] the actual capital structure that he uses is shown in Table VI.

TABLE VI		
Components	AG's Capitalization	Assigned Costs
Short-Term Debt	2.32%	0.63%
Long-Term Debt	52.06%	6.32%
Preferred Stock	1.65%	7.75%
Common Equity	+ 43.97%	9.25%
Total Capitalization	100.000%	

The Commission is adjusting Kentucky-American's capital structure as shown in Table VII.

[178] Direct Testimony of J. Randall Woolridge at 13.

TABLE VII

	Short-Term Debt	Long-Term Debt	Preferred Stock	Common Equity	Total Capital
Proposed Capital Structure	$ 8,319,538	$187,073,668	$ 5,935,810	$158,013,385	$359,342,401
Slippage Adjustment	1,249,182	(1,448)	(52)	(1,315)	1,246,367
Working Capital AIP Days	(458,956)	571	18	484	(457,883)
Deferred Compensation	185,788	(234)	0	(190)	185,364
Tax Exempt Financing	(11,214)	9	9	9	(11,187)
Capital Structure	$ 9,284,338	$187,072,566	$ 5,935,785	$158,012,373	$360,305,062
Capital Rates	2.577%	51.921	1.647%	43.855%	100.000%

Short-Term and Long-Term Debt. Kentucky-American originally projected short-term and long-term interest rates of 2.085 percent and 6.41 percent, respectively.[179] It subsequently revised its original projections to reflect the current financial market conditions, which results in short-term and long-term interest rates of 1.90 percent and 6.38 percent, respectively.[180] Using its analysis of the current federal funds rate, the AG proposed short-term and long-term interest rates of 0.63 percent and 6.32 percent, respectively.[181] Upon review of the supporting calculations, the Commission finds that Kentucky-American's revised projections result in a more current projection of the forecasted debt rates. For this reason, we find the proposed cost of debt is reasonable and should be accepted.

[179] Direct Testimony of Michael A. Miller, Exhibit MAM-3.

[180] Rebuttal Testimony of Michael A. Miller at 6 and Rebuttal Exhibit MAM-1; Base Period Update Filing, Exhibit 37, Schedule J-3 (filed July 15, 2010).

[181] Direct Testimony of J. Randall Woolridge at 14.

Preferred Stock. Kentucky-American proposed an embedded cost of preferred stock of 7.75 percent.[182] No party objected to this forecasted cost rate. We find that the proposed embedded cost of preferred stock is reasonable and should be accepted.

Return on Equity. Kentucky-American recommends a return on equity ("ROE") ranging from 10.8 percent to 12.1 percent and specifically requests an ROE of 11.5 percent based on its discounted cash flow model ("DCF"), the ex ante risk premium method, the ex post risk premium method, and Capital Asset Pricing Model ("CAPM").[183]

To perform its analysis, Kentucky-American witness Vander Weide employed two comparable risk proxy groups in its analysis. The first proxy group consists of eleven water companies included in the *Value Line Investment Survey* ("*Value Line*") that: pay dividends; did not decrease during any quarter for the past two years; have at least one analyst's long-term growth forecast; and are not part of an ongoing merger. All of these water companies have a *Value Line* Safety Rank of at least 3, which is the average of all *Value Line* companies.[184]

Dr. Vander Weide's second proxy group consisted of twelve natural gas local distribution companies. Each company was in the natural gas distribution business; paid quarterly dividends over the last two years; had not decreased dividends over the last two years; was not involved in an ongoing merger, and had at least two analysts'

[182] Application, Exhibit 37, Schedule J-1.

[183] Direct Testimony of Michael A. Miller at 15; Direct Testimony of James H. Vander Weide at 3-4.

[184] *Id.* at 22-23.

estimates of long-term growth included in the I/B/E/S consensus growth forecast.[185] Each also had a *Value Line* Safety Rank of 1, 2 or 3 and an investment grade bond rating.[186]

Dr. Vander Weide applied a quarterly DCF model to the water company and gas proxy groups. He relied upon the gas company proxy group solely for the ex ante risk premium ROE estimation. He relied upon Standard & Poor's ("S&P") 500 stock portfolio and the S&P Public Utility Index to derive the ex post risk premium ROE estimation. Though Dr. Vander Weide performed CAPM analyses using both proxy groups, he did not rely upon the CAPM estimations in reaching his recommended ROE. He rejected the CAPM analyses because the average beta coefficient for the proxy companies was significantly below a value of 1 and because several of the water companies have relatively low market capitalization.[187] As part of his ROE recommendations, Dr. Vander Weide also made adjustments for flotation costs.

AG witness Woolridge takes issue with several aspects of the methodology that Kentucky-American used to develop its proposed ROE. First, he argues that Dr. Vander Weide has made an inappropriate adjustment to the spot dividend yield. Second, he asserts that the Kentucky-American study relies exclusively on the

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[185] *Id.* at 27. I/B/E/S is a division of Thomson Reuters that reports analysts' earnings per share ("EPS") growth forecasts for a broad group of companies. The I/B/E/S growth rates are widely circulated in the financial community, include the projections of reputable financial analysts who develop estimates of future EPS growth, are reported on a timely basis to investors, and are widely used by institutional and other investors.

[186] *Id.* at 27.

[187] *Id.* at 3.

forecasted growth rates of Wall Street analysts and *Value Line* to compute the equity cost rate, that the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased, and that the estimated long-term EPS growth rates of *Value Line* are overstated. Third, Dr. Woolridge contends that the risk premium and CAPM approaches require an estimate of the base interest rate and the equity risk premium. In both approaches, he asserts, Dr. Vander Weide's base interest rate is above current market rates.[188]

Dr. Woolridge also takes strong exception to Dr. Vander Weide's position in measuring the equity risk premium, as well as the magnitude of equity risk premium. He contends that Dr. Vander Weide has used excessive equity risk premiums that do not reflect current market fundamentals. Dr. Vander Weide uses a historical equity risk premium which is based on historic stock and bond returns and calculates an expected risk premium in which he applies the DCF approach to the S&P 500 and public utility stock. Risk premiums based on historic stock and bond returns, Dr. Woolridge asserts, are subject to empirical errors which result in upwardly biased measures of expected equity risk premiums. Dr. Woolridge further asserts that Dr. Vander Weide's projected equity risk premiums, which use analysts' EPS growth rate projections, include unrealistic assumptions regarding future economic and earnings growth and stock returns.[189]

Contending that the utility has failed to identify any actual flotation costs and questioning whether the necessary conditions that support the use of a flotation cost

[188] Direct Testimony of J. Randall Woodridge at 3-4.

[189] *Id.* at 73-75.

adjustment are present in the current case, Dr. Woolridge challenges the appropriateness of Dr. Vander Weide's use of flotation cost adjustment in his DCF analysis.[190]

Finally, Dr. Woolridge takes issue with Kentucky-American's proxy group. He notes that Dr. Vander Weide's proxy group of water companies includes a water company with less than two years of dividend payments and another which has agreed to be sold to an investor group.[191] Six of the twelve members of the gas proxy group, he further notes, have a low percentage of revenues derived from the regulated gas distribution business or are engaged in riskier business ventures. As Dr. Vander Weide's gas proxy group has a number of companies with significant non-regulated gas activities and is riskier than regulated water and gas companies, the AG argues, the results for that group should be ignored.[192]

Dr. Woolridge conducted his own analysis, applying the DCF model and the CAPM methods to a water proxy group and a gas proxy group and affording primary weight to the results of the DCF analysis. Based upon that analysis, he proposes an ROE range from 7.3 percent to 9.3 percent and recommends an awarded ROE of 9.25.[193]

To perform his analysis, Dr. Woolridge uses a proxy group of nine publicly-held water utility companies covered by *AUS Utility Reports* and a second proxy group of

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[190] *Id.* at 71-73.

[191] *Id.* at 53.

[192] *Id.* at 53-54.

[193] *Id.* at 2.

nine natural gas distribution companies covered by the Standard Edition of *Value Line*. The water proxy group received 92 percent of its revenues from regulated water operations and had a common equity ratio of 49.0 percent. The gas proxy group received 63 percent of revenues from regulated gas operations and had a common equity ratio of 52 percent.[194]

Dr. Woolridge argues that the use of natural gas distribution companies as a proxy for Kentucky-American is appropriate since the financial data necessary to perform a DCF analysis on the members of the water proxy group, as well as analysts' coverage of water utilities, is limited. He also argues that the return requirements of gas companies and water companies should be similar as both industries are capital intensive, heavily regulated, and provide essential services with rates set by state regulatory commissions.[195]

Dr. Woolridge places significant emphasis on current economic conditions and concluded that short- and long-term credit markets have "loosened" considerably and that the stock market has rebounded significantly from 2009's lows.[196] He further states that the investment risk of utilities is currently very low and that the cost of equity for utilities is among the lowest of all industries in the U.S. as measured by their betas.[197]

LFUCG witness Baudino also takes exception to several aspects of Kentucky-American's ROE analyses. First, he notes the presence of highly diversified gas

[194] *Id.* at 11-12.

[195] *Id.* at 10-11.

[196] *Id.* at 10.

[197] *Id.* at 20-21.

companies in Kentucky-American's gas proxy group whose businesses are more diverse, unregulated and tend to have great risk. As such, he argues, they are "poor proxies for . . . [Kentucky-American's] low-risk water distribution operation" and tend to inflate Kentucky-American's DCF analysis.[198]

Mr. Baudino contends that Dr. Vander Weide erred by failing to include forecasted dividend growth in his DCF analyses. With respect to regulated utility companies, he argues, dividend growth provides the primary source of cash flow to the investor. While earnings growth fuels dividend growth, *Value Line*'s dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. *Value Line*'s dividend growth forecasts, Mr. Baudino states, suggest that near-term dividend growth will be less than forecasted earnings growth. Dr. Vander Weide's failure to include this information, Mr. Baudino concludes, led to a significant overstatement of all of his DCF results.[199]

Mr. Baudino further contends that Dr. Vander Weide's use of a quarterly DCF model is unnecessary and overcompensates investors. This model, he argues, compensates investors twice for the reinvestment effect associated with the quarterly payment of dividend. Moreover, he states, quarterly compounding is likely already accounted for in a company's stock price since investors know that dividends are paid quarterly and that they may reinvest those cash flows.[200]

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[198] Direct Testimony of Richard A. Baudino at 15.

[199] *Id.* at 33, 37-38.

[200] *Id.* at 38-39.

Mr. Baudino also argues that the use of a flotation adjustment is unnecessary. To the extent that investors even account for such costs, he states, current stock prices already account for flotation costs. The adjustment, he states, essentially assumes that the current stock price is wrong and must be adjusted downward to increase the dividend yield and the resulting cost of equity.[201]

Mr. Baudino also alleges several problems with Dr. Vander Weide's risk premium approach. He argues that Dr. Vander Weide's assumption that investors require an unchanging risk premium based on historic returns of stocks over bonds fails to take into account that changing economic conditions will affect investors' risk premium requirements. Under current economic conditions, Mr. Baudino asserts, investors' requirements may differ significantly from a long-term historical risk premium.[202]

Mr. Baudino next argues that Dr. Vander Weide failed to adjust his historical risk premium, which uses the S&P 500 stock portfolio, for the risk premium expectations for utility companies. Investor-expected risk premiums for water utility stocks over bonds, Mr. Baudino states, are likely much lower than the expected risk premium for unregulated companies in the S&P 500. Using the S&P 500 risk premium, Mr. Baudino argues, overstates the risk premium ROE for a low-risk water company such as Kentucky-American.[203]

Mr. Baudino also contends that Dr. Vander Weide's use of S&P utilities to calculate the expected risk premium ROE for Kentucky-American is inappropriate. Low-

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[201] *Id.* at 39-40.

[202] *Id.* at 41.

[203] *Id.* at 41-42.

risk water companies, he contends, are likely to have a lower expected ROE than the S&P Utilities and thus a risk premium using the S&P Utilities will overstate the risk premium ROE for regulated water companies.

Mr. Baudino also disputes Dr. Vander Weide's decision to disregard his CAPM results because CAPM underestimates required returns for securities with betas of less than one. Mr. Baudino argues that there is little evidence that the CAPM bias has any applicability to regulated utilities. Regulated water utilities, he asserts, have low betas because they are low in risk.[204]

Mr. Baudino performed several DCF analyses for two comparison groups of utilities, one composed of regulated water utilities and one composed of regulated natural gas distribution utilities.[205] He also performed two CAPM analyses. Based upon the results of these analyses, he recommended a ROE range from 9.0 percent to 10.0 percent and a ROE of 9.50 percent.[206]

In his rebuttal testimony, Dr. Vander Weide addresses the criticism of his analysis and critiques the analyses of Intervenor witnesses. Countering criticism of his proxy group selections, he notes that his proxy group of natural gas utilities has a higher *Value Line* safety rating and higher average bond rating than AWWC and his proxy group of water utilities has a higher S&P bond rating than AWWC and the same *Value Line* safety ranking.[207]

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[204] *Id.* at 42-43.

[205] *Id.* at 13-16.

[206] *Id.* at 31.

[207] Rebuttal Testimony of James Vander Weide at 5.

As to his use of EPS growth rates in his DCF analysis, Dr. Vander Weide argues that differences in EPS growth rates and historical growth rates for water utilities do not reduce the reliability of his analysis. He contends that differences in historical and projected growth rates for the water utilities indicate that water utilities are likely to grow more rapidly in the future than they have in the past. His DCF model, he asserts, is intended to capture investors' expectations about the future. Moreover, he argues, historical growth rates are inherently inferior to analysts' forecasts because analysts' forecasts already incorporate all relevant information regarding historical growth rates and also incorporate the analysts' knowledge about current conditions and expectations regarding the future. He refers to several studies that "demonstrate that stock prices are more highly correlated with analysts' growth rates than with either historical growth rates or the internal growth rates."[208]

Dr. Vander Weide rejected criticism of his use of a quarterly DCF model. He testified that all of the companies within his proxy groups paid quarterly dividends and noted that the same applied for those companies in Dr. Woolridge's proxy group. He further testified that, as the DCF model is based on the assumption that a company's stock price is equal to the expected future dividends associated with investing in the company's stock, an annual DCF model cannot be based upon this assumption when dividends are paid quarterly.[209]

Dr. Vander Weide takes exception to Dr. Woolridge's internal growth method. He argues that this method underestimates the expected growth of his proxy companies

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[208] *Id.* at 13-25.

[209] *Id.* at 62.

by neglecting the possibility that such companies can grow by issuing new equity at prices above book value. He notes that many of the proxy companies are currently engaging in this practice or are expected to do so in the future. This possibility is noteworthy, he asserts, because the water industry is expected to undertake substantial infrastructure investments in the near future and to finance those investments in part through this practice.[210]

Dr. Vander Weide also expresses concerns about aspects of Mr. Baudino's analysis. He contends that the use of DPS growth forecasts to estimate the growth component of Baudino's DCF model understates long-run future growth and that such forecasts are less accurate indicators of long-run future growth than earnings growth forecasts.[211]

Based upon our review of the record, we find that Kentucky-American's proposed ROE should be denied. We find Kentucky-American's use of natural gas distribution companies as proxies for water utilities to be inappropriate. While natural gas distribution companies and water utilities have similar types of fixed investments, the nature of the risks that each industry faces is sufficiently different to prevent the use of natural gas companies as a proxy. While both industries deliver a commodity through underground pipes, several of the companies within the natural gas proxy group that Kentucky-American has used engage in exploration, production, transmission, and other non-regulated and non-distribution activities. These activities extend well beyond a distribution function and have greater risk.

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[210] *Id.* at 12.

[211] *Id.* at 55-59.

We find that an ROE of 9.7 percent provides Kentucky-American with a fair and reasonable rate of return. In reaching our finding, we have focused upon the water utilities within the proposed proxy group. This group consists of large and small publicly traded water utilities. While Kentucky-American is a relatively small water utility, it is part of a large, multi-state operation that has access to investment capital under conditions that few small water utilities could obtain. Accordingly, we are of the opinion that this group is a more accurate indicator of risk and market expectations.

This finding also reflects Kentucky-American's recent regulatory history. Kentucky-American's frequency of rate case applications since 1992 clearly demonstrates management's focused efforts to minimize regulatory risk and the risk associated with the recovery of capital investments. Kentucky-American has applied for rate adjustments on a more frequent basis than other water utilities within the proxy group. Furthermore, Kentucky-American has used a forecasted test period with each rate application–a mechanism that also tends to reduce the risk associated with the recovery of capital investments.

In reaching our finding, we have also excluded any flotation cost adjustment from our analysis and have placed much greater emphasis on the DCF and the CAPM model results of the water utility proxy groups. While recognizing the value of historic data for use in obtaining estimates, we have also considered analysts' projections regarding future growth. Finally, in assessing market expectations, we have given considerable weight to present economic conditions.

Weighted Cost of Capital. Applying the rates of 6.38 percent for long-term debt, 7.75 percent for preferred stock, 1.90 percent for short-term debt, and 9.70 percent for common equity to the adjusted capital structure produces an overall cost of capital of 7.74 percent. We find this cost to be reasonable.

Authorized Increase

The Commission finds that Kentucky-American's net operating income for rate-making purposes is $28,116,014. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $18,825,137.[212]

Cost-of-Service Study

Kentucky-American included with its application a cost-of-service allocation study[213] that is based upon the base-extra capacity method. This methodology is widely recognized within the water industry as an acceptable methodology for allocating costs.[214] This Commission has also accepted the use of this methodology for cost allocation and development of water service rates. No party has objected to the findings of the cost-of-service study. We accept the study's findings.

General Water Rates

The rates and charges contained in the Appendix to this Order are based on findings contained in the cost-of-service study, as adjusted by our findings regarding the

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Net Investment Rate Base	$ 363,255,997
Multiplied by: Rate of Return	x 7.7400%
Operating Income Requirement	$ 28,116,014
Less: Forecasted Net Operating Income	- 16,717,697
Operating Income Deficiency	$ 11,398,317
Multiplied by: Revenue Conversion Factor	x 1.651571600
Increase in Revenue Requirement	$ 18,825,137

[213] Application, Exhibit 36.

[214] American Water Works Association, *Principles of Water Rates, Fees and Charges* 50 (5th Ed. 2000).

reasonableness of the costs in the proposed test period. Those rates and charges will produce the required revenue requirement based upon the forecasted sales. For a residential customer who uses an average of 5,000 gallons per month, these rates will increase his or her monthly bill from $27.46 to $35.40, or approximately 28.9 percent.

Service to Low-Income Customers

The Commission recognizes that a significant portion of Kentucky-American's customers have annual incomes that are at or below the Federal Poverty Guideline.[215] We further recognize that the approved rate adjustment will more adversely affect these customers than those with higher annual incomes. CAC has presented several proposals to provide some relief to the customers. Having carefully considered each of these proposals, we find that each should be implemented or given further study and consideration.

CAC has proposed that Kentucky-American be required to maintain more complete records regarding customer payment and termination of service for non-payment in a manner that permits systematic analysis. It notes that Kentucky-American presently cannot ascertain the number of customers who make late payments, a customer's frequency of late payments, the number of terminations for late payments, or

[215] In 2008, approximately 15.4 percent of Fayette County residents were living at or below the Federal Poverty Guideline. Of the remaining eight counties in which Kentucky-American provides water service, the percentage of persons living at or below the poverty line in 2008 ranged from 9.7 percent to 17.0 percent. It is estimated that 15.4 percent of Fayette County residents were at or below the Federal Poverty Guideline in 2008. Of the remaining eight counties in which Kentucky-American has operations, the percentage of individuals at or below the poverty line ranged from 9.7 percent to 17.0 percent. *See* U.S. Census Bureau Small Area Income and Poverty Estimates, *available at* http://www.census.gov/did/www/saipe/data/index.html (last visited Nov. 2, 2010).

the specific service (e.g., water, sewer, water quality) for which non-payment has occurred and serves as the basis for termination.[216] CAC witness Burch testified this information would provide a better means of assessing the affordability of Kentucky-American's rates and developing policies to assist low income customers.[217] Kentucky-American confirms that its present records system will not allow quick and cost-effective analysis on these subjects.[218]

If the Commission is to properly review and assess the affordability of Kentucky-American's rates, we must have accurate and reliable information regarding customer payment. Given the limitations of Kentucky-American's record systems, that information is presently unavailable. Accordingly, we find that Kentucky-American should develop and implement as soon as possible a plan to accurately record and determine the number of customers making payments after the due date, the frequency of late payments by each customer, the number of service terminations for nonpayment for each customer account and company-wide, and the specific services that were not paid when water service is terminated for non-payment.

CAC urges the Commission to restructure Kentucky-American's proposed rate design to create a graduated, tiered rate structure. It asserts that an inclining block structure that provides for a minimum quantity of water at an inexpensive level and increasing rates based upon increased usage would benefit all customers. Such a rate

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[216] CAC's Brief at 6-7.

[217] VR: 8/11/10; 15:41:45-15:43:20.

[218] Kentucky-American's Response to CAC's Second Request for Information, Item 1.

structure, CAC argues, would make a minimum quantity of water affordable to low-income customers and would promote conservation. As an alternative to immediately implementing such rate design, CAC requests that Kentucky-American be directed to "work with the Attorney General, low income advocates, and other interested parties to design a rate system on this concept."[219] It further proposes that the Commission establish a collaborative effort that includes all interested parties and Commission Staff to address affordability issues. All other parties appear in agreement with the proposal to create a working group to study rate design issues.

We find insufficient evidence in the record to support CAC's rate design proposal or to clearly demonstrate that the implementation of such proposal will benefit low-income customers or create appropriate pricing signals. Accordingly, we have not incorporated CAC's rate design proposal into Kentucky-American's rates. We find, however, that CAC's proposal should be further studied and additional customer data gathered to permit a thorough assessment of the proposal's potential effects.

Recognizing that the affordability of water service is a complex and multi-faceted subject that must be approached on several levels, the Commission finds considerable merit to CAC's proposal to undertake a collaborative effort to study this subject. Such an effort, however, should not be limited to examining potential rate design options to enhance the affordability of water service, but should consider all potential regulatory and legislative solutions to this perplexing issue. We find that Kentucky-American should initiate this collaborative effort by arranging, within 60 days of the date of this Order, a meeting of all interested parties to discuss and study potential regulatory and

[219] CAC's Brief at 8.

legislative solutions to the increasing lack of affordability of water service for low income customers. Moreover, Kentucky-American should file with the Commission periodic written reports on the status of these meetings and submit a final written report on the collaborative group's efforts no later than November 1, 2011. We direct Commission Staff to assist the collaborative group's efforts to the fullest extent that its limited resources permit and encourage all interested parties, including those groups that did not intervene in this proceeding, to actively participate.

Other Issues

Tap-On Fees. Kentucky-American proposes to increase its tap-on fees from 13 percent to 22 percent to reflect the five-year average cost of a service connection. Kentucky-American's tap fees are currently based upon an average of actual costs of connections from 2005 to 2007. Kentucky-American witness Bridwell testified that significant increases in connection costs have occurred since that time. Raw material costs increased dramatically in 2008 and have not yet returned to pre-2008 levels. Additionally, the number of new service connections significantly decreased in 2008 and 2009 due to a reduction in economic activity. As a result, there were fewer installations over which to spread the fixed costs related to such installations.[220]

Kentucky-American has historically used a three-year average of connection costs to establish its tap-on fees. In the present case, it proposes to base these fees on a five-year average to reduce the effect of increasing costs and current economic conditions. The Commission acknowledges and supports Kentucky-American in its

[220] Direct Testimony of Linda C. Bridwell at 2-3.

efforts to lessen the increase in tap-on fees for its customers and accepts the change in the calculation of the average costs over a five-year period.

Based upon our review of the record, we find that the proposed revisions to tap-on fees will not result in fees that exceed the cost of the service connection, are reasonable, comply with 807 KAR 5:011, Section 10, and should be approved.

Reduced Rate/Free Service for Public Fire Hydrants.[221] Kentucky-American currently provides water service to approximately 7,388 public fire hydrants.[222] LFUCG owns approximately 6,811 of these hydrants.[223] Approximately 6,920 of these hydrants are located in Fayette County. Under the terms of Kentucky-American's present rate schedules, governmental bodies pay a monthly or annual charge for each hydrant.

LFUCG argues that a reasonable portion of the public fire hydrant costs should be assigned to other customer classes to reflect the benefits that other users of the water distribution system receive from the existence of public fire protection service (for example, lower insurance rates and enhanced public safety) and the existence of hydrants (for example, improved water quality due to greater line-flushing capability). It

[221] Under the terms of Kentucky-American's tariff, a public fire hydrant is a fire hydrant contracted for or ordered by Urban County, County, State or Federal Governmental agencies or institutions and connected to a municipal or private fire connection used solely for fire protection purposes. Tariff of Kentucky-American Water Company, P.S.C. Ky. No. 6, Twenty-Third Revised Sheet No. 53.

[222] Kentucky-American's Response to LFUCG's First Request for Information, Item 9.

[223] *Id.*

requests that the Commission order or otherwise encourage Kentucky-American to develop a free or reduced public fire hydrant rate for use in a future rate proceeding.[224]

While KRS 278.170(3) permits a utility to provide free or reduced-rate service for fire protection purposes, LFUCG's proposal raises a number of difficult policy issues. Free or reduced-rate fire hydrant service effectively shifts the fire protection service costs from governmental bodies to other users and thus requires a corresponding increase in the rates for general water service customers. Because Kentucky-American has a unified tariff and serves areas outside of Fayette County for which no fire protection service is provided, the potential exists that Kentucky-American customers who reside outside of Fayette County will be subsidizing through their rates fire protection services for Fayette County residents.[225]

LFUCG's proposal will produce an income transfer from Kentucky-American customers to local, state, and federal government entities. The public, which includes Kentucky-American ratepayers, currently pays indirectly for public fire hydrant service through local, state and federal taxes. Government agencies use collected tax revenues to pay Kentucky-American directly for public fire hydrant service. Allocating the costs of providing public fire hydrant service to general service customers will reduce or eliminate the charges that government entities must pay and effectively provide those agencies with additional funds for other uses. It will also require general

[224] LFUCG's Brief at 8.

[225] To the extent that public fire hydrant service benefits non-customers who own property in Kentucky-American's service area, the effect of allocating the costs of public fire hydrant service to general service customers is to provide a subsidy to those non-customers.

service customers to pay higher rates for water service. Unless a reduction occurs in these customers' taxes to offset the increased amount for water service, these customers will be paying a larger portion of their income for the same level of services.

Allocating public fire hydrant service costs to general service rates also increases the likelihood that pricing signals will be distorted and public accountability will be lessened. Under the current pricing scheme, the cost of public fire hydrant service is clearly known to the public. Kentucky-American bills the governmental entity for that service. The governmental entity must allocate and pay those bills from its available funds. Its records and budgeting process are subject to public review and inspection. The decisions regarding the availability of public fire hydrant service and amount of public funds (and assessed private funds) to be devoted to such service are made in full public view and with the opportunity for public comment. Allocating public fire hydrant service costs to general service users effectively hides these costs from public view and discussion and renders informed public decisions on the availability and appropriateness of such service more difficult.

In light of these concerns and as LFUCG will be the primary beneficiary of any free or reduced public fire hydrant rate, the Commission finds that LFUCG, not Kentucky-American, is the most appropriate party to develop a proposal for such rate. We respectfully decline LFUCG's request to order or otherwise encourage Kentucky-American to develop a free or reduced public fire hydrant rate for future use without adequate evidence. By this Order, however, we direct that Kentucky-American make its records available to LFUCG and respond to all reasonable inquires from LFUCG regarding public fire hydrant service to enable LFUCG to develop its own proposal.

Should Kentucky-American fail to comply with this directive, LFUCG should inform the Commission of this failure and request our assistance in obtaining the required information.

Tariff Revisions Related to Fire Protection Mains. Kentucky-American currently does not meter water usage provided through fire service connections. Despite restrictions in Kentucky-American's tariff that require that water from these connections be used solely for fire protection purposes,[226] Kentucky-American employees have observed water withdrawals from some fire service connections for other purposes.[227] As a result, Kentucky-American proposes revisions to its present tariff to permit the installation of meters on fire service connections and the assessment of usage charge on all non-fire related flows when a reasonable belief exists that water is being used for non-fire protection purposes.

The Commission finds that the proposed revisions are reasonable and should be approved. They are consistent with the findings and recommendations of a recently completed report on Kentucky-American's non-revenue water.[228] Enforcement of Kentucky-American's proposed tariff language will likely reduce the level of non-revenue water by permitting Kentucky-American to track and charge usage on these previously unmetered service connections. It will also provide a means through which Kentucky-American can enforce its prohibition against non-fire protection usage on such connections.

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[226] Kentucky-American Water Company Tariff No. 6, Sheet 10 (Feb. 17, 1983).

[227] Direct Testimony of Linda C. Bridwell at 7.

[228] Gannett Fleming, Analysis of Non-Revenue Water, Task 5 (Sep. 2009).

Demand Management Plan. In its brief, LFUCG requests that the Commission order Kentucky-American to develop a new demand management plan. In support of its request, it notes that Kentucky-American's existing plan was developed in 2001 and that significant changes to Kentucky-American's operations have occurred since then. It further asserts that a new plan is essential to determining whether Kentucky-American has sufficient water to provide wholesale service to other water utilities within the central Kentucky area and the direction of Kentucky-American's planning. The Commission agrees and by this Order directs Kentucky-American to file such plan no later than the filing of its next application for general rate adjustment.

Termination of Water Service for Debts Owed to LFUCG. Pursuant to an agreement with LFUCG, Kentucky-American bills and collects from its Fayette County customers LFUCG Water Quality Management Fee, LFUCG Landfill Charges, and LFUCG Sewer charges. This agreement provides that monies received from its customers will be applied to unpaid charges in the following priority: (1) water service charges; (2) LFUCG Water Quality Charges, (3) LFUCG Landfill Charges, and (4) LFUCG Sewer charges.[229] The agreement provides that water service will be terminated for failure to pay LFUCG sewer charges. Given the agreement's priority provisions which effectively allocate a customer's payment of LFUCG sewer charges to LFUCG Water Quality Charges and Landfill Charges, Kentucky-American has agreed to terminate a customer's water service for a customer's failure to pay LFUCG Water Quality Charges or LFUCG Landfill Charges.[230]

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[229] Kentucky-American's Response to Hearing Data Request, Item 13.

[230] *Id.*, Item 14.

In Case No. 95-238,[231] Kentucky-American applied for approval of its initial agreement with LFUCG and for a deviation from 807 KAR 5:006, Section 14, to permit the discontinuance of water service to any customer who failed to pay sanitary sewer charges owed to LFUCG. While noting that that 807 KAR 5:006, Section 14, "permits a utility to discontinue service only for nonpayment of charges for services which it provides," we found that KRS Chapter 96 expressly authorized such agreements[232] and required a water supplier to discontinue water service to premises for a customer's failure to pay sewer service charges when the governing body of the municipal sewer facilities identifies the delinquent customer and notifies the water supplier to discontinue service.[233] We further found that, as the provisions of KRS Chapter 96 and 807 KAR 5:006, Section 14, were in conflict and that KRS Chapter 96 was more specific, those provisions controlled.[234] Hence, we reasoned, no deviation from 807 KAR 5:006, Section 14, was required and no Commission approval of the Agreement between Kentucky-American and LFUCG was required.

[231] Case No. 95-238, An Agreement Between Lexington-Fayette Urban County Government and Kentucky-American Water Company for the Billing, Accounting and Collection of Sanitary Sewer Charges, at 3 (Ky. PSC June 30, 1995). The agreement addressed only billing and collection of sanitary sewer charges and did not address either water quality fees or landfill fees.

[232] *See* KRS 96.940.

[233] *See* KRS 96.934.

[234] Case No. 95-238, Order of June 30, 1995, at 3-4. The conflict existed between provisions of KRS Chapter 96 and KRS 278.280(2), which provides the Commission "shall prescribe rules for the performance of any service or the furnishing of any commodity of the character furnished or supplied by" a utility.

Kentucky-American's present practice of discontinuing service for failure to pay landfill fees and water quality management fees, however, has no statutory basis. KRS Chapter 96 requires a water supplier to discontinue water service only to a premise that fails to pay municipal sanitary sewer charges. It makes no reference to landfill fees or water quality or storm drainage charges. Consequently, there is no conflict between KRS Chapter 96 and 807 KAR 5:006, Section 14, nor are there any restrictions on that regulation's application to the water utility's practice of discontinuing water service for failure to pay a landfill fee or water quality management fee.

As a general rule, a public utility "cannot refuse to render the service which it is authorized to furnish, because of some collateral matter not related to that service."[235] The purpose of the water quality management fee is to fund LFUCG's storm water management program and surface water runoff facilities.[236] The fee is based upon the size and the condition of a real estate tract. Similarly, LFUCG's landfill fee is intended to fund "the operational and capital costs of solid waste disposal" and is based on the

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[235] Maurice T. Brunner, Annotation, *Right of Municipality to Refuse Services Provided By It to Resident for Failure of Resident to Pay for Other Unrelated Services*, 60 A.L.R. 3d 760 (1974). *See also* 64 Am. Jur. 2d *Public Utilities* § 23 (2010); OAG 79-417 (July 17, 1979). *But see Cassidy v. City of Bowling Green, Ky.*, 368 S.W.2d 318 (Ky. 1963).

[236] LFUCG Ordinance No. 73-2009.

number and type of waste disposal containers.[237] We can find no relationship between storm water management or garbage collection and water service.[238]

Absent express statutory authorization or a deviation from 807 KAR 5:006, Section 14, Kentucky-American may not terminate water service because of a customer's failure to pay charges related to storm water service or garbage service. Kentucky-American, however, has effectively engaged in this practice by applying any amounts billed and collected for LFUCG to landfill disposal and water quality management fees before sanitary sewer charges. The Commission finds that Kentucky-American should cease this practice immediately and should instead apply any monies collected for LFUCG first to LFUCG sanitary sewer charges and then to landfill disposal and water quality management fees.[239]

SUMMARY

After consideration of the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. Kentucky-American's proposed rates would produce revenues in excess of those found reasonable herein and should be denied.

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[237] LFUCG Code, Section 16-16.

[238] In contrast, Kentucky courts have found the use of water service and sanitary sewer service to be "interdependent." *See, e.g., Rash v. Louisville and Jefferson County Metropolitan Sewer Dist.*, 217 S.W.2d 232, 239 (Ky. 1949).

[239] 807 KAR 5:006, Section 27, authorizes deviations from the Commission's General Rules for good cause. Kentucky-American may apply to the Commission for a deviation from 807 KAR 5:006, Section 14, to continue its current practice. Our action should not be construed as expressing a position on the merits of such application.

2. Kentucky-American's proposed tap-on fees are reasonable and should be approved.

3. Kentucky-American's proposed rules related to fire protection mains are reasonable and should be approved.

4. The rates in the Appendix to this Order are fair, just, and reasonable and should be charged by Kentucky-American for service rendered on and after September 28, 2010.

5. Kentucky-American should, within 60 days of the date of this Order, refund to its customers with interest all amounts collected from September 28, 2010 through the date of this Order that are in excess of the rates that are set forth in the Appendix to this Order. Interest should be based upon the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order.

IT IS THEREFORE ORDERED that:

1. Kentucky-American's proposed rates are denied.

2. The rates set forth in the Appendix to this Order are approved for service rendered on and after September 28, 2010.

3. Within 60 days of the date of this Order, Kentucky-American shall refund to its customers with interest all amounts collected for service rendered from September 28, 2010 through the date of this Order that are in excess of the rates set forth in the Appendix to this Order.

4. Kentucky-American shall pay interest on the refunded amounts at the average of the Three-Month Commercial Paper Rate as reported in the Federal

Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order. Refunds shall be based on each customer's usage while the proposed rates were in effect and shall be made as a one-time credit to the bills of current customers and by check to customers that have discontinued service since September 28, 2010.

5. Within 75 days of the date of this Order, Kentucky-American shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in the Appendix to this Order.

6. Within 20 days of the date of this Order, Kentucky-American shall file its revised tariff sheets containing the rates approved herein and signed by an officer of the utility authorized to issue tariffs.

7. Kentucky-American's proposed revisions to Tariff Sheets No. 52, No. 53, and No. 53.1 are approved.

8. LFUCG's request that Kentucky-American develop a free or reduced public fire hydrant rate for use in a future rate proceeding is denied.

9. Kentucky-American shall make all records related to fire protection service and public fire hydrant service available for LFUCG's inspection and review and shall respond to all reasonable inquiries from LFUCG regarding public fire hydrant service within a reasonable time.

10. Within 60 days of the date of this Order, Kentucky-American shall develop and file with the Commission a plan to accurately record and determine the number of customers making payments after the due date, the frequency of late payments by each customer, the number of service terminations for non-payment for each customer account and company-wide, and the specific service(s) that are not paid when water

service is terminated for non-payment. This plan shall further identify the cost of implementing such plan and the time necessary for implementation.

11. Unless the Commission otherwise directs, Kentucky-American shall implement the plan submitted in accordance with ordering paragraph 10 within 120 days of the date of this Order.

12. No later than the filing of its next application for general rate adjustment Kentucky-American shall file a revised demand management plan with the Commission.

13. a. Within 60 days of the date of this Order, Kentucky-American shall initiate the collaborative effort described in this Order by convening a meeting of all interested parties, to include all parties of record in this case, to identify and study potential regulatory and legislative solutions to enhance and improve the affordability of water service for low-income customers.

b. No later than January 31, 2011, and every month thereafter, Kentucky-American shall file with the Commission a written report on the efforts of the collaborative group to develop potential regulatory and legislative solutions to enhance and improve the affordability of water service for low-income customers.

c. No later than November 1, 2011, Kentucky-American shall file with the Commission a final written report on the collaborative group's efforts.

14. Until granted a deviation from 807 KAR 5:006, Section 14, authorizing such practice, Kentucky-American shall refrain from its practice of applying monies collected from a customer for LFUCG to landfill disposal and water quality management fees before applying those monies to LFUCG sanitary sewer charges and from terminating water service to a customer who has failed to pay fully all LFUCG fees and

charges where the amount paid is equal to or exceeds all outstanding charges for LFUCG sanitary sewer service.

15. Any documents filed with the Commission pursuant to ordering paragraphs 5, 6, 10, 12, and 13 shall reference this case number and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED
DEC 14 2010
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director