

**BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:	)	
	)	
DOCKET TO EVALUATE	)	
CHATTANOOGA GAS COMPANY'S	)	DOCKET NO. 07-00224
GAS PURCHASES AND RELATED	)	
SHARING INCENTIVES	)	
	)	
	)	

**CONSUMER ADVOCATE'S RESPONSES TO CHATTANOOGA GAS COMPANY'S
FIRST DISCOVERY REQUESTS**

Robert E. Cooper, Jr., Attorney General and Reporter for the State of Tennessee, through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), respectfully responds to the first discovery requests of Chattanooga Gas Company ("CGC" or "the Company").

GENERAL OBJECTIONS

1. The Consumer Advocate objects to the definitions and instructions contained in the data requests to the extent that the definitions and instructions attempt to impose on the Consumer Advocate a burden or obligation greater than that required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

2. The Consumer Advocate objects to the data requests to the extent they call for information and the production of documents which are protected from disclosure by the attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's data requests to the extent they seek information relating to matters not at issue in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, The Consumer Advocate does not concede that such information is relevant, material or admissible in evidence. The Consumer Advocate reserves all rights to

object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations to supplement its responses beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's data requests to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

6. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the Company's own possession, custody or control. It is unduly burdensome and oppressive to require the Consumer Advocate to respond or produce documents that are equally available to the Company.

7. The Consumer Advocate's objections and responses to these requests are based on information now known to it. The Consumer Advocate reserves the right to amend, modify or supplement its objections and responses if it learns of new information.

8. The Consumer Advocate's responses to these requests are made with out waiving or intending to waive the right to object to the use of any information provided in response to any subsequent proceeding or trial of this or any other action. The Consumer Advocate's responses to these requests are also not a waiver of any of the foregoing objections or any objections it has made or may make with respect to any similar, related, or future data request, and the Consumer Advocate specifically reserves the right to interpose any objection to further requests notwithstanding any response or lack of objection made in this response.

9. The Consumer Advocate will supplement its responses in accordance with the requirements of state law.

10. The Consumer Advocate expressly incorporates these general objections into its responses set forth below.

Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request as follows:

Discovery Request No. 1

Identify by name all individuals, not employed by the Office of the Attorney General for the State of Tennessee, with whom an employee or employees of the Consumer Advocate and Protection Division discussed the Asset Management Agreements provided in response to Question 35, Sequent Energy Management's Chart of Accounts provide in response to Question 28, or the Chattanooga IMCR filing and the Chattanooga Book provided in response to Question 24, of the Consumer Advocate and Protection Division's first set of discovery dated March 18,

2008. For each individual identified, provide a copy of the Affidavit required by paragraphs 14 and 4 of the Agreed Protective Order issued March 4, 2008.

RESPONSE: None.

Discovery Request No. 2

- a. Identify the jurisdictions and dockets or cases in which Dr. Brown has provided testimony addressing management of natural gas supply assets (pipeline contracts, natural gas storage contracts, etc).
- b. Identify the jurisdictions and dockets or cases in which Mr. Buckner has provided testimony addressing management of natural gas supply assets (pipeline contracts, natural gas storage contracts, etc).

RESPONSE:

- a. Dr. Brown has testified in Tennessee in TRA dockets 97-01364, 06-00175, and 01-00704 / 02-00850 (Consolidated).
- b. None.

Discovery Request No. 3

Identify the jurisdictions and dockets or cases in which Dr. Brown has provided testimony addressing the amount of pipeline transportation capacity and/or the amount of storage capacity needed by a natural gas local distribution company.

RESPONSE:

Dr. Brown has testified in Tennessee in TRA dockets 97-01364, 06-00175, and 01-00704 / 02-00850 (Consolidated).

Discovery Request No. 4

Provide copies of all articles, books, reports, etc. authored by Dr. Brown that address the

management of natural gas supply assets (pipeline contracts, natural gas storage contracts or facilities), the amount of pipeline transportation capacity, or the amount of storage capacity needed by a natural gas local distribution company.

RESPONSE: See Exhibit A attached.

Discovery Request No. 5

Produce copies of all documents -- including, without limitation, workpapers, spreadsheets, summaries, charts, notes, exhibits, articles, journals, treatises, periodicals, publications, reports, records, statements, Internet web pages, or financial information -- in your possession that you contend support the factual assertions, conclusions, or opinions of any of your witnesses in this matter and also all such documents that contradict the factual assertions, conclusions, or opinions of any of your witnesses in this matter.

RESPONSE: The Consumer Advocate relies upon all documents provided with its testimony or referred to in its testimony and all documents provided in response to this set of discovery requests. The Consumer Advocate also reserves the right to rely upon any documents provided by CGC in its responses to discovery requests or to requests by the TRA staff and upon any CGC testimony and documents submitted with CGC testimony. Also, see Exhibit B attached.

Discovery Request No. 6

Produce copies of all documents -- including, without limitation, workpapers, spreadsheets, summaries, charts, notes, exhibits, articles, journals, treatises, periodicals, publications, reports, records, statements, Internet web pages, or financial information -- relied upon by any of CAPD's witnesses in evaluating, reaching conclusions, or formulating an opinion in this matter.

RESPONSE: The Consumer Advocate relies upon all documents provided with its testimony or referred to in its testimony and all documents provided in response to this set of discovery requests. The Consumer Advocate also reserves the right to rely upon any documents provided by CGC in its responses to discovery requests or to requests by the TRA staff and upon any CGC testimony and documents submitted with CGC testimony. Also, see Exhibit C attached.

Discovery Request No. 7

Identify the source and provide the complete definition of the term, "operator" as used by the CAPD in Items 70, 71, 72, and 74 of its first discovery request issued March 18, 2008.

RESPONSE: See Exhibit D attached. Dr. Brown utilized the definition of “delivery point operator.”

Discovery Request No. 8

On page 3 of his testimony Dr. Brown states:

“The need for CGC’s LNG facilities appears to be declining and potentially could be replaced by ETNG’s LNG service. CGC’s LNG facilities are in CGC’s rate base. CGC should provide the TRA with a study explaining the benefits and detriments of using ETNG’s LNG service versus maintaining CGC’s LNG facilities in the rate base, both operationally and financially. This issue could also be treated in a triennial independent review.”

- a. Provide all workpapers, studies, reports prepared by or possessed by the Consumer Advocate and Protection Division that address CGC’s use of its LNG facility.
- b. Provide all workpapers, studies, reports prepared by or possessed by the Consumer Advocate and Protection Division that identify the benefits and cost of CGC obtaining LNG service from ETNG.
- c. Provide all workpapers, studies, reports prepared by or possessed by the Consumer Advocate and Protection Division that identify benefits and cost of CGC maintaining its LNG facilities.

RESPONSE: See Exhibit E attached.

Discovery Request No. 9

Admit that the Annual Non Firm Sales volumes identified by Dr. Brown on page 13 of his testimony includes the volumes provided to customers served under the I-1,L-1, F-1, T-1, T-2, and T-3 Rate Schedules. If denied, provide full explanation.

RESPONSE: Admitted.

Discovery Request No. 10

Admit that neither Dr. Brown nor other members of the CAPD's Staff prepared an analysis of Chattanooga Gas Company's firm customer peak day demand, design day demand, or load duration curves. If denied, provide a full explanation and copies of all such analyses.

RESPONSE: Admitted.

Discovery No. 11

On page 21 of his testimony Dr. Brown states:

"For example, the table at page 13 of this testimony shows that nonfirm customers use so much capacity throughout the year that there is no reason to conclude that they avoid on-peak usage. In TRA Docket 06-00175, CGC's most recent rate case, its witnesses were silent about peak use of the pipeline capacity. They limited their testimony to a discussion of the peak use of the distribution system."

- a. Admit that pipeline capacity cost is recovered through the Purchased Gas Adjustment / Actual Cost Adjustment (PGA/ACA) mechanism and is not included in CGC's base (distribution) rates. If denied, provide a complete explanation including any supporting documents, workpapers, or analysis.
- b. Admit that the most recent rate case, TRA Docket 06-00175 addressed CGC base (distribution) rates and did not address gas costs (including commodity cost, pipeline reservation, transportation, and storage cost). If denied, provide a complete explanation including any supporting documents, workpapers, or analysis.

RESPONSE:

a. The Consumer Advocate denies that Dr. Brown's testimony says, "its witnesses were silent about peak use". The testimony actually says, "its witnesses did not address the peak use". Otherwise, admitted.

b. The Consumer Advocate denies that Dr. Brown's testimony says, "its witnesses were silent about peak use". The testimony actually says, "its witnesses did not address the peak use". Also, the Consumer Advocate denies the request for admission and relies on Dr. Brown's testimony in TRA docket 06-00175, pages 50 through 59. See Exhibit F attached.

Discovery No. 12

On page 21 of his testimony Dr. Brown states:

“As I have already discussed, a portion of CGC’s year-round firm pipeline capacity on ETNG could be replaced by seasonal pipeline capacity on ETNG, and there is a potential for CGC’s LNG plant to be replaced by ETNG’s LNG service. However, based on the data I have used regarding Issue 5, my opinion is that CGC appears not to have a planning process which joins the needs of firm customers to transportation, peaking and storage capacity.”

- a. Provide copies of all analysis or studies prepared by Dr. Brown or other employees of the CAPD that quantify or otherwise address of the amount of :
 1. firm Tennessee Gas Pipeline capacity needed by CGC,
 2. firm ETNG capacity needed by CGC;
 3. firm SONAT pipeline capacity needed by CGC;
 4. firm pipeline capacity needed by CGC in total;
 5. peaking capacity needed by CGC;
 6. storage capacity needed by CGC.
- b. Identify all data used by Dr. Brown in forming his opinion regarding Issue 5.
- c. Provide copies and identify the source of all data identified in (b) above that is not included in Dr. Brown’s testimony or exhibits.

RESPONSE:

- a. See Dr. Brown’s testimony in this case and see Exhibits B and F attached.
- b. Dr. Brown used all sources of data cited in his testimony and the documents produced in response to this set of discovery requests.
- c. Dr. Brown used the documents produced in response to this set of discovery requests.

Discovery No. 13

On page 23 of his testimony Dr. Brown states:

“However, the lack of connection between Mr. Buchanan’s peak use on a distribution system and peak use of pipeline capacity is shown in Mr. Heintz’s testimony. At page 9, lines 11-12 Mr. Heintz says “a complete listing of the external and internal allocation factors used in the COSS is shown in Exhibit DAH-3.”

- a. Admit that Mr. Heintz did not include pipeline capacity cost in the class cost of service study filed in Docket 06-00175. If denied, provide complete explanation and supporting documentation.
- b. Admit that Mr. Heintz did not address peak use of pipeline capacity in his testimony or exhibits filed in Docket 06-00175. If denied, provide a complete explanation including supporting documentation.
- c. Admit that the volumes and allocation factors shown on page 24 of Dr. Brown’s testimony as taken from Exhibit DAH-3 in Docket 06-000175 were not proposed for or used in the allocation of pipeline capacity, but were the DDDCs for the different rate classes used in the class cost of service study to allocate the distribution system and reflect the demand put on the distribution system on the design day by the different customer rate classes. If denied, provide a complete explanation including supporting documentation.

RESPONSE: Admitted.

Discovery No. 14

On page 75 of his testimony Dr. Brown states:

“CAPD raised that issue in CAPD discovery request 30, which is provided below. For the period January 1, 2004 through March 31, 2007 SEM’s transactions had a value of \$708 million, about 100 times larger than the revenues credited to CGC’s ratepayers. However, the wording of CGC’s reply may suggest that “Sales Volume Dth” may include the throughput volumes displayed at page 10 of this testimony, which are CGC’s overall sales. If this were the case, then the ratio of 100, which I noted above, would decline to 50.”

- a. Admit that the CAPD discovery request 30 asked for Sequent’s **total** dollar amount and volumes of sales related to asset management contracts between Sequent and CGC. If denied, provide a complete explanation.

- b. Admit that 50% of the gross margin is to be credited to CGC's rate payers. If denied, provide a complete explanation.
- c. Admit that gross margin is total sales revenue less the cost of gas and is not the same as total dollar amount of sales. If denied, provide a complete explanation.
- d. Admit that in discovery request 30 the CAPD did not request that the gross margin related to asset management contracts be identified. If denied, provide a complete explanation.
- e. Admit that the \$708 million identified in response to CAPD discovery request 30 is the **total** dollar amount of sales as requested and not gross margin related to the asset management contracts between Sequent and CGC. If denied, provide a complete explanation.

RESPONSE: Admitted.

Discovery Request No. 15

On page 11 of his testimony, Mr. Buckner includes the following question and answer:

- “Q. How does CGC's ratepayer compensation compare to the ratepayer compensation provided nationally by other LDCs?
- A. When compared to ratepayer compensation in state jurisdictions other than AGL, the ratepayer compensation is too low.”
- a. Provide copies of the analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that compare the ratepayers' compensation in each of the remaining 44 states in which AGLR distribution companies do not operate with CGC's ratepayer compensation. If the analysis or study does not address the ratepayer compensation in each of the remaining 44 states, identify each state that is not included. Identify all assumptions used and the source of all data used in the analysis.
 - b. Provide copies of the analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that compare the ratepayer compensation for non-AGLR distribution utilities in the 6 states in which AGLR distribution utilities operate with CGC's ratepayer

compensation. Identify the source of all data used in the analysis. Identify all assumptions used and the source of all data used in the analysis.

- c. Provide a copy of each Asset Management Agreement reviewed by Mr. Buckner when comparing CGC ratepayer compensation with the ratepayer compensation for other local distribution companies.
- d. Provide a copy of each regulatory commission order addressing asset management that Mr. Buckner reviewed when comparing CGC ratepayer compensation with the ratepayer compensation for other local distribution companies.

RESPONSE:

a. Mr. Buckner's testimony is the only written form of his analysis. Mr. Buckner's testimony relies on sharing arrangements in Tennessee, Indiana, Delaware, New York, Ohio, Connecticut, Massachusetts, Maryland, and Pennsylvania. Mr. Buckner also reviewed the sharing arrangements submitted by CGC in response to the Consumer Advocate's discovery requests. Mr. Buckner's testimony was not intended to be and was not represented to be a 50-state survey. The states not included in the testimony can be determined by deduction, but the lack of inclusion of any particular state does not imply that such state treats consumers the same as or less generously than CGC's 50/50 arrangement, which CGC can change at any time to 50/25/25. The sources of data used are referenced in the testimony. The assumption in Mr. Buckner's analysis is that Tennessee consumers should be treated fairly.

b. Mr. Buckner's testimony is the only written form of his analysis. The sources of data used are referenced in the testimony. The assumption in Mr. Buckner's analysis is that Tennessee consumers should be treated fairly.

c. Mr. Buckner reviewed the asset management agreements provided by CGC in response to the Consumer Advocate's discovery requests, the settlement agreement in Cause No. 42973, Indiana Utility Regulatory Commission, and the Commission or Authority orders on sharing arrangements cited in the testimony. Copies were provided with the testimony.

d. Copies were provided with the testimony.

Discovery Request No. 16

On page 11 of his testimony, Mr. Buckner states:

"The Indiana Utility Regulatory Commission, in Cause No. 42973, approved an asset management arrangement in which consumers receive the bulk of the

benefits. Part 3-e of the order, starting on page 7, discusses the “Profit Sharing.” The order divides the capacity assets into two equal parts that are treated differently in the method of deriving benefits from them. One half of the capacity is devoted to “a pre-arranged sales process that will solicit bids.” Consumers receive 85% of the value derived from that process. The other half of the capacity is retained by the utility, and the utility markets that half of the capacity itself. Customers receive 75% of the value derived from that process. Obviously, there are differences between this example and the asset management contract at issue in the present docket, but the point is that it is possible and practical for a state regulatory authority to establish a system of marketing capacity assets that is designated primarily to benefit the consumers who have paid 100% of the costs for those assets.”

- a. Provide a copy of the asset management agreement subject to approval in Cause No. 42973 referenced by Mr. Buckner.
- b. Identify and explain the differences in the example and the asset management contract at issue in the present docket that Mr. Buckner recognizes in his testimony.

RESPONSE:

- a. The Consumer Advocate does not possess a copy of the asset management agreement.
- b. The obvious differences that Mr. Buckner referenced are that the Indiana sharing arrangement divides the assets at issue into two parts and provides for different methods of obtaining value for those assets with sharing for the method used for half of the assets set at 85/15 and with sharing for the method used for the other half of the assets set at 75/25. The sharing in the case at bar is 50/50 with CGC having the option to reduce the consumers’ share to 25% at any time, despite the fact that Tennessee consumers must pay for 100% of the costs of the assets.

Discovery Request No. 17

Page 15 of Mr. Buckner’s testimony includes the following question and answer:

“Q. If the sharing between CGC and the asset manager is changed to 85% for CGC and 15% for the asset manager, would you expect the potential asset managers would bid smaller amounts for the annual guaranteed minimum than they would under 50%/50% sharing.

A. Most likely, yes.”

Provide all analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that identifies the potential impact on the guaranteed minimum payment, if the sharing percentage were changed from 50%/50%. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner’s testimony is the only written form of his analysis. Mr. Buckner’s answer to the question is not essential to his opinions regarding the appropriate sharing in the case at bar. If the bids for the annual guaranteed minimum were to remain the same or increase as a result of the proposed sharing arrangement, Mr. Buckner’s opinions regarding the appropriate sharing in this case would remain the same. The sources of the data used are cited in the testimony. The assumption in Mr. Buckner’s analysis is that Tennessee consumers should be treated fairly.

Discovery Request No. 18

On page 16 Mr. Buckner states:

“. . . but consumers could be better off over the long term with a higher guaranteed percentage of the sharing rather than with a higher annual guaranteed minimum payment.”

- a. Provide all analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that identifies the potential impact on ratepayers of a higher percentage of sharing rather than a higher annual guaranteed minimum. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner’s testimony is the only written form of his analysis. The sources of the data used are cited in the testimony. The assumption in Mr. Buckner’s analysis is that Tennessee consumers should be treated fairly.

Discovery Request No. 19

On page 23 Mr. Buckner states:

“Therefore, the amount paid by Sequent for the right to utilize or market assets is not representative of the fair market value of such assets.”

- a. Provide all analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that identifies the “fair market value of such assets” referenced by Mr. Buckner on page 23 of his testimony. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner’s testimony is the only written form of his analysis. The sources of the data used are cited in the testimony. The assumption in Mr. Buckner’s analysis is that Tennessee consumers should be treated fairly.

Discovery Request No. 20

On page 27 Mr. Buckner states:

“If CGC were to engage in asset management itself, then all of the earning from this activity would inure to the ratepayers.”

Provide all analysis or studies prepared by Mr. Buckner or other member s of the CAPD Staff that identifies the additional investment in facilities, the additional costs that CGC would incur, and the potential earnings that would inure to the ratepayers if CGC were to engage in asset management itself. Identify all assumptions used and the source of all data used in the analysis or study.

Provide all analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that compares the earnings that would inure to the ratepayers if CGC were to engage in asset management itself with the amount provided to the ratepayers under the current asset management agreements. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner’s testimony is the only written form of his analysis. The sources of the data used are cited in the testimony. The assumption in Mr. Buckner’s analysis is that Tennessee consumers should be treated fairly.

Discovery Request No. 21

Beginning on page 27 Mr. Buckner states:

“The TRA currently conducts audits of natural gas costs. If CGC were to independently manage their assets, then those management activities could not be immune to audits by the TRA or its audit representatives.”

Admit or deny that provision 7 of CGC’s RFP Procedures for selection of Asset Manager and/or Gas included in the Tariff approved by the TRA provides:

“The Company shall retain all RFP documents and records for at least four (4) years and such documents and records shall be subject to the review and examination of the TRA Staff. The Asset Manager shall maintain documents and records of all transactions that utilize the Company’s gas supply assets. All documents and records of such transactions shall be retained for two years after termination of the agreement and shall be subject to review and examination by the Company and the TRA Staff.”

If denied, provide complete explanation and supporting documentation.

Admit or deny that paragraphs 21.3 and 21.4 of the Asset Management Agreement effective April 1, 2008 provides:

“21.3 The Parties expressly recognize that both the Company and the TRA have audit rights with respect to any and all financial and/or physical transactions undertaken in connection with this Agreement. As such the Asset Manager must provide work space for said audit(s) and appropriate personnel at it own expense.

21.4 Asset Manager shall provide the Company and/or TRA the opportunity for periodic local reviews of Asset Management operations and systems, as may be required by the Company and/or the TRA.”

If denied, provide complete explanation and supporting documentation.

Admit or deny that provision 7 of CGC's RFP Procedures for selection of Asset Manager and/or Gas as stated in CGC's Tariff, and paragraphs 21.3 and 21.4 of the Asset Management Agreement effective April 1, 2008 provide that the TRA can examine and review (audit) the asset management activities related to the gas supply assets included in the agreement the same as it does gas costs, and that such asset management activities are not immune from audit by the TRA.

If denied, provide complete explanation and supporting documentation.

RESPONSE: The Consumer Advocate denies that paragraph 21.4 of the asset management contract mentions “Asset Management operations and systems”. The actual quote is “Asset Managers operations and systems”. The Consumer Advocate also denies that the underlining is an accurate part of the quotation both for the tariff provision and for the provisions of the asset management contract. The requests for admission fail to note that the Company underlined parts of the quotations for emphasis and that such emphasis is not in the original documents. Otherwise, the Consumer Advocate admits the allegations. The requests for admission indicate that CGC does not understand this portion of Mr. Buckner’s testimony. The portion of Mr. Buckner’s testimony quoted by CGC addresses the specific hypothetical situation in which CGC independently manages its assets. The Company’s quotations of tariff provisions regarding the asset management contract and quotations of provisions within the asset management contract are irrelevant in this context.

Discovery Request No. 22

In footnote 9 on page 14 of his testimony Mr. Buckner identifies several regulatory dockets that he alleges support his position. Provide a copy of each asset management agreement related to these dockets that Mr. Buckner reviewed during his investigation related to this docket. If Mr. Buckner did not review the related asset management agreements, so state.

RESPONSE: Mr. Buckner reviewed the asset management agreements that CGC provided in response to the Consumer Advocate's discovery requests and the settlement agreement in Cause No. 42973, Indiana Utilities Regulatory Commission, a copy of which was provided with the testimony. Mr. Buckner reviewed the Commission or Authority orders establishing the sharing arrangements that are cited in the testimony but did not review the asset management contracts that followed those Commission or Authority orders. Copies of the Commission or Authority orders were provided with the testimony.

Discovery Request No. 23

Page 22 of Mr. Buckner's testimony includes the following question and answer:

"Q. Do you recommend any other changes that the TRA should make to the contract that is put out for bid when the current three-year contract approaches expiration?

A. Yes. The CAPD argued for specific changes to the contract in TRA Docket #08-00012. There was some concern expressed at the hearing on those issues that the bidders relied on the form contract in making their bids. If the TRA orders the changes prior to the RFP going out, that concern would not exist the next time bidders analyze the contract. The CAPD's arguments on those issues are included in its brief and reply brief in TRA Docket # 08-00012."

For each change to the contract recommended by Mr. Buckner and the CAPD, addressed here, provide copies of the analysis or studies that Mr. Buckner or other employees of the CAPD prepared that support his opinion that the changes in the contract are needed. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner's testimony is the only written form of his analysis. The sources of data are cited in the testimony. The assumption is that Tennessee consumers should be treated fairly. The Consumer Advocate's Brief and the Consumer Advocate's Reply Brief in TRA docket 08-00012 support this part of Mr. Buckner's testimony, and the asset management agreement is an integral part of this analysis. CGC already possesses copies of these documents, and copies are available on the TRA's website at the link for docket 08-00012.

Discovery Request No. 24

On page 15 of his testimony, Dr. Brown states:

“The major difference between CGC’s use of its SONAT and ETNG capacity suggest CGC may be able to reduce and to convert much of its year round capacity from ETNG to seasonal capacity covering the winter months of November through March.”

Provide copies of all documents or information in the possession of the CAPD related to the availability of seasonal firm transportation capacity on ETNG.

RESPONSE: See Exhibit G attached.

Discovery Request No. 25

On page 16 of his testimony, Dr. Brown states:

“Both Atmos Energy Corporation and the Knoxville Utilities Board have seasonal contract with ETNG.”

Provide copies, in the possession of the CAPD, of the contracts between Atmos Energy Corporation and ETNG and the Knoxville Utilities Board and ETNG that provide for seasonal firm transportation, and any other documents that supports Dr. Brown’s statement.

RESPONSE: See Exhibit G attached.

Discovery Request No. 26

On page 16 of his testimony, Dr. Brown provides an illustration of how a utility could reduce cost by replacing 41,500 Dth/d year-round capacity with 10,000 Dt/d year-round capacity and 20,000 Dt/d seasonal capacity.

Provide copies of the analysis or studies that Dr. Brown or other employees of the CAPD prepared that supports the reduction of the deliverability capacity from 41,500 Dt/d to 30,000 Dt/d. Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: See Dr. Brown’s testimony in this case and Exhibit H attached. The sources used are cited. The assumption is that Tennessee consumers should be treated fairly.

Discovery Request No. 27

On page 21 of his testimony Mr. Buckner states:

“While the RFP procedures for selection of an asset manager and /or gas provider allow for the receipt of competitive bids, the criteria for choosing the winning bid proposal is ambiguous.”

Identify the specific provision(s) of the criteria for choosing the winning bid proposal that Mr. Buckner allege are ambiguous and provide copies of any documents in the possession of the CAPD that supports for his opinion.

RESPONSE: The ambiguities in the selection criteria are that the appropriate weighting of the four enumerated criteria is unexplained in the provision and that the language “at a minimum” preceding the enumeration of the criteria indicates that there could be unknown criteria. The Consumer Advocate’s concerns about these ambiguities are greatest in the context of an affiliate bidder, because such ambiguities could be used by CGC to the unfair disadvantage of non-affiliated bidders.

Discovery Request No. 28

On page 4 of his testimony Mr. Buckner states:

“As previously mentioned, CGC has contracts with the pipeline companies for transportation and storage. The contractual assets along with CGC’s physical assets are managed by Sequent to meet the firm full gas supply requirements of CGC.”

Identify CGC’s physical assets that Mr. Buckner alleges are managed by Sequent.

Provide copies of all documents in Mr. Buckner’s or the CAPD’s possession that supports Mr. Buckner’s position that Sequent manages the physical assets identified in (a) above.

RESPONSE: The asset management contract in effect between CGC and its affiliate Sequent supports Mr. Buckner’s statement, and CGC already has a copy of the asset management contract. The physical assets that Mr. Buckner alleges are managed by Sequent are all assets included in the asset management contract between CGC and its affiliate Sequent.

Discovery Request No. 29

On page 27 of his testimony Mr. Buckner states:

“Ultimately, the TRA should exercise its duty to balance the needs of the ratepayer with just and reasonable rates for the shareholder for every activity of CGC’s provision of natural gas service.”

Provide all analysis or studies prepared by Mr. Buckner or other members of the CAPD Staff that quantifies the “reasonable rates for shareholders.” Identify all assumptions used and the source of all data used in the analysis.

RESPONSE: Mr. Buckner's testimony is the only written form of his analysis. The sources of data are cited in the testimony. The assumption is that Tennessee consumers should be treated fairly.

Discovery Request No. 30

Beginning on page 12 of his testimony Mr. Buckner states:

"It is limited in that the CAPD cannot discuss in an open proceeding before the TRA other AGL's asset management agreements with CGC's sister LDCs."

Provide copies of all documents in the position of the CAPD that support the statement that AGL is an asset manager for any CGC's sister LDCs or any other LDC.

RESPONSE: The statement is an inadvertent error. Mr. Buckner meant to say "Sequent" rather than "AGL".

Discovery Request No. 31

On page 40 of his testimony, Dr. Brown states:

"On its face CGC's decision to terminate contract 33653 six months ahead of term, and to reduce its receipt capacity at Ridgetop without seeking compensation appears as a capital contribution by CGC to SEM and an abandonment of the true value of such capacity would have been assigned in a market transaction.

Provide all analysis or studies prepared by Dr. Brown or other members of the CAPD Staff that quantifies the "true value of such capacity" as referred to by Dr. Brown. Identify all assumptions used and the source of all data used in the analysis or study.

RESPONSE: See Dr. Brown's testimony. The sources of data are cited.

Establishing the true, market-base value of the Ridgetop receipt capacity requires the following assumptions:

There is a buyer, and there is a seller.

There is free choice for the buyer and free choice for the seller.

The buyer and the seller are motivated by self-interest.

CGC has a self-interest independent of Sequent's self-interest.

Neither party can induce the other to accept terms that harm their respective self-interests.

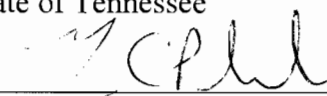
CGC's selection and provision of pipeline receipt points and delivery points is not an activity governed by a regulatory agency's tariff.

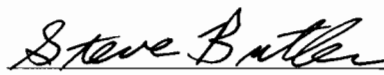
Sequent makes offers to CGC, and CGC makes counteroffers to Sequent.

Ridgetop is essential for Sequent to make profit from its deliveries to Transco.

RESPECTFULLY SUBMITTED,

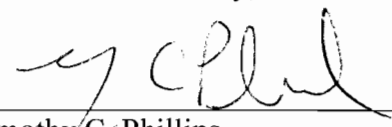
ROBERT E. COOPER, JR., B.P.R. #10934
Attorney General and Reporter
State of Tennessee


TIMOTHY C. PHILLIPS, B.P.R. #12751
Senior Counsel


STEPHEN R. BUTLER, B.P.R. #14772
Assistant Attorney General
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202
(615) 741-8722
FAX: (615) 532-2910

Certificate of Service

I hereby certify that a true and correct copy of the foregoing was served via first-class U.S. Mail, postage prepaid, hand delivery, commercial delivery, or electronic mail upon the parties of record on June 20, 2008.


Timothy C. Phillips

120821

TRA DOCKET NUMBER 07-00224

EXHIBIT A

The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Stephen N. Brown

The FERC completed a remarkable turnaround in regulatory philosophy in its gas pipeline restructuring order.

Competition for natural gas supply will promote the nation's economic growth. That idea describes the essence of Federal Energy Regulatory Commission (FERC) Order No. 636 and provides the driving force behind the commission's effort to restructure the natural gas industry. But the FERC's eventual success ultimately depends on the spirit of "cooperative competition": The willingness of individual players to share information about day-to-day pipeline operations and the vital conditions that determine rate design and prices.

The FERC itself is acutely aware of this vulnerability. That is why the commission framed Order 636 with language that simultaneously coaxes, cajoles, and urges the industry to do its patriotic duty (see box).

This language makes FERC's order 636 truly remarkable. It tells the pipelines that their traditional way of doing business blocks the spread of competition within the natural gas industry. This finding was unthinkable twenty years ago. The natural gas industry was built on the principle of bundled, city-gate, firm sales service. During the industry's early years, certificates of convenience and necessity were issued to pipelines only if they offered such service to distribution companies. The industry's building block is now an unlawful restraint of trade.

The pipelines' old virtue is now a vice because the merchant function is gradually fading away. In the first quarter of 1984 pipeline sales made up 94 percent of throughput. By the second quarter of 1991 pipeline sales totaled only 12 percent of throughput. Nevertheless, in 1991 pipeline sales consumed over 60 percent of peak-day capacity. This surprising mismatch between throughput and capacity told the FERC that pipeline sales enjoy a clear

advantage over the open-access firm transportation of nonpipeline natural gas:

Free-flowing Information

The FERC intends to solve the fairness problem by establishing equivalency between bundled, city-gate firm sales by the pipeline and open-access firm transportation of nonpipeline natural gas. The solution lies with the idea of "No-Notice Transportation Service." Success will depend on cooperation between the various segments of the industry, as the FERC is quite aware:

[We] expect the pipelines and all interested participants to craft . . . the operating conditions needed to

The Spirit of 636

Drawing on Patriotism:

"[We] . . . remind the industry that it is in the nation's best interest and the industry's interest . . . to keep gas flowing and deliverable when and where needed and . . . not unreasonably inhibit the meeting of gas purchasers and gas sellers in a competitive market." [Order No. 636, p. 96.]

From Virtue to Vice:

"[The] pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry . . . this harm has an unreasonable impact on gas sellers and is an unlawful restraint of trade." [Order No. 636, p. 39.]

To Level the Field:

"Pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors." [Order No. 636, p. 32.]

An Open Book, But Who Will Read It?

Pipelines in a Fishbowl:

Pipelines will retain operational control, but will perform in a fishbowl, since all buyers and sellers must now constantly monitor pipeline operations.

Second-guessing by Customers:

Buyers and sellers are likely to develop "shadow" operations groups that not only will monitor operating conditions, but are also likely to second-guess the pipelines from time to time.

Information Overload:

A tremendous need will arise for accurate, speedy, and voluminous information on storage facilities, receipt and delivery points, pressure, pumping stations, capacity reallocations, and anything else that might be viewed as relevant.

ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlement on a daily basis without incurring daily balancing and scheduling penalties.

To its lasting credit, the FERC recognizes that "no-notice" markets will not be fully competitive without another simultaneous development — the rapid and free flow of information. The FERC clearly says "that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations." This policy will work only if all players cooperate. Any effort to tilt the scales by withholding or disguising relevant information may easily subvert the FERC's goal of uniting gas purchasers and gas sellers in a competitive market place. The importance of good and timely information cannot be overestimated for a competitive market, whether it's the New York Stock Exchange, the Chicago Board of Trade, or the natural gas industry.

The FERC's policy on information flow has major implications. The pipelines may not yet have realized that the order lays out their operations for all to see. It's just like letting one person cut the cake while others choose which piece they want. For example, the pipelines must make electronic bulletin boards accessible to all users and no one will be granted preferential access to the boards:

The pipelines must keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records . . . pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information.

The FERC is right to be cautious, considering the im-

pending modernization of the nation's telecommunications infrastructure and uncertain behavior of the players in the natural gas industry. How will the new infrastructure affect the competitiveness of the natural gas industry? Will the pipelines really want to give up their advantage of occupying 60 percent of the peak-day capacity, particularly when their sales are less than 20 percent of annual throughput? Do local distribution companies (LDCs) really want to jump into a competitive market with complexities that rival those of a major stock exchange? Will the upstream and downstream pipelines really cooperate with one another?

Rate Design

The restructuring hearings will not deal with the single biggest rate design issue for pipelines: transportation cost recovery through the "straight fixed-variable method" (SFM). This rate design definitely affects the central feature of the FERC's restructuring proposal: The presumed willingness of gas buyers to participate in "no-notice transportation service."

The SFM method removes all fixed costs from the pipeline's commodity charge for transporting gas. For years the FERC allowed significant amounts of fixed costs in the pipeline's commodity charge. The commission now believes such practice inhibits competition by preventing gas purchasers from making accurate comparisons of prices, terms, and conditions offered by various gas sellers. The SFM method corrects this mistake and promotes "head-to-head, gas-on-gas competition."

The FERC prefers the SFM rate design but suggests that it may be avoided by any particular pipeline if the parties agree on an alternative costing method. If the parties can't persuade the FERC to deviate from its preference, or if they lack a consensus on rate design, the SFM method will prevail. The odds favor SFM, since rate design is rarely characterized by harmony. It's an impossible goal because the customers' load factors are too diverse. In fact, the SFM method reduces costs for customers with high annual load factors, and increases costs for customers with poor load factors. This explains both the support and the opposition to SFM — with a rate design consensus unlikely, there will be no viable alternative.

The SFM method will increase costs for some customer groups. The FERC has agreed to limit such increases to 10 percent and to phase in the increase over a four-period after the pipeline's initial compliance filing. But after four years, the phase-in terminates and the limitations expire for SFM-related cost increases. After that customers are on their own; they must adapt to changed circumstances. The burden cannot be laid at the door of producers or pipelines. It falls exclusively on gas consumers and perhaps their agents acting as gas purchasers.

What does this mean for hot new designer rates? It means that "no-notice" transportation rates must strongly

reflect the prevailing operating conditions on the pipeline.

I'm not advocating a different price for every hour of the year on every different section of the line. But I am advocating that the industry get far away from the idea that "one rate fits all." The nature of a competitive market place allows for some tailoring and customizing of individual prices and contract terms. Indeed, if the market doesn't exhibit these characteristics at all, then it's not really a competitive market. Customizing may be one way to develop a "no-notice" competitive transportation market. There's certainly room for this market considering that interruptible transportation now accounts for 51 percent of pipeline deliveries to market.

Tailored rate designs ought to reflect a match between the customers needs, the producer's supply, and the pipeline's operating conditions. This brings me back to my emphasis on the need for good information. More than ever before, there will be an emphasis on the optimal scheduling of pipeline flows, storage, maintenance, controlling, and shifting consumer demand. In this situation command and control of information is paramount because a competitive market inevitably reduces profit margins for the poorly organized and inefficient party. To be effective negotiators, gas purchasers and sellers must have the ability to recognize and act on the opportunities offered by the ebb and flow of a pipeline's operating conditions. FERC clearly understands this and accordingly has decided to make pipeline operations an open book for both gas buyers and sellers.

I hope LDCs and their customers are ready for the responsibilities of a competitive natural gas market. The LDCs fit the national pattern already noted by the FERC: Buying a lot of gas on the spot market, using interruptible transportation, and relying on pipeline sales for peak-day purchases, while keeping overall bills below the potential cost of exclusive reliance on pipeline gas. The LDCs have had an extended learning opportunity. It's up to them to take this experience and skillfully apply it the emerging market that the FERC is now creating.

The competitive market certainly raises uncertainties at the federal and state levels. How will the FERC draw the boundary between proprietary information and information required to make the market competitive? How does state regulation establish risk-sharing between the core customers and an LDC making a gas purchase on their behalf? Will a purchased gas adjustment (PGA) clause continue to serve a useful purpose once pipelines comply with Order 636?

These questions don't exhaust the possibilities, but sooner or later, perhaps in a rate case setting or in a notice of inquiry, the LDCs will have to show their state regulatory body that they've read the open book on pipeline operations and made good use of it. This would serve everyone's interest, and the LDCs should avoid putting truth to old sayings: "You can lead a horse to water but you can't make it drink," or, in the case of pipeline operations, "seeing a book open does not

Order 636-A: A Short-term Solution?

On July 30 the FERC met and voted to approve Order No. 636-A, in which it slightly relaxed its effort to push the natural gas industry into the information age. Pipeline capacity released for less than one calendar month will now require neither advanced posting on electronic bulletin boards nor bidding.

But the practicality of omitting short-term transactions from posting and bidding requirements will diminish as the industry learns better how to handle transactions of various sizes and duration. These short-term events cause a nuisance only when the players in the market are not ready to use or interpret the information that they provide. Any competitive market features short-term, low-volume transactions, and there is no inherent reason why such transactions should hinder a competitive market in its allocative efficiency. Thus, we can likely expect that the FERC will eventually withdraw Order 636-A and replace it in a subsequent rule making.

make its reader think."

Competition Versus Reliability

The importance of pipeline operations cannot be overstated because major changes in public policy towards regulated industry are constrained by technical considerations. The FERC's restructuring efforts are no exception. At the inception of the "Mega-NOPR," pipeline system reliability was incompatible with competition — one condition precluded the other. With the industry's help, the FERC resolved this apparent contradiction and found that system reliability and competition coexist. Neither one preempts the other.

With a little imagination, the FERC might apply this reasoning to the issue of transmission access in the electric power industry. All that's needed is to substitute "electric utility" for "pipeline" and "no-notice transmission" for "no-notice transportation". Can the FERC make competition in the electric industry compatible with system reliability? Perhaps not, but the electric industry may soon be hard pressed to explain why system reliability and competition cannot coexist in the power industry.

The FERC has offered a number of individual steps that, if taken quickly and cooperatively, will speed the gas industry's adoption of competitive market practices. But I emphasize the *fragility* of the FERC's proposal and the need for cooperation to make the system work. Hot new designer rates won't sell in the market place if the players torpedo the restructuring. I agree with the unspoken sentiment expressed by the FERC: Restructuring the industry will work only if the players adopt the spirit of "cooperative competition." That should characterize all bargaining between sellers, buyers, and pipelines.

Stephen N. Brown is chief of the Bureau of Energy Efficiency, Auditing and Research, Utilities Division, of the Iowa Utilities Board.

The opinions expressed here do not necessarily represent those of the Iowa Utilities Board.

STATE OF TENNESSEE

Office of the Attorney General



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LUCY HONEY HAYNES
ASSOCIATE CHIEF DEPUTY
ATTORNEY GENERAL

MAILING ADDRESS

P O BOX 20207
NASHVILLE, TN 37202
July 30, 2004

MICHAEL E. MOORE
SOLICITOR GENERAL

CORDELL HULL AND JOHN SEVIER
STATE OFFICE BUILDINGS

TELEPHONE 615-741-3491
FACSIMILE 615-741-2009

Honorable Pat Miller
Chairman
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243

**RE: UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY
CORPORATION, INCENTIVE PLAN ACCOUNT AUDIT
Docket 01-000704**

Dear Chairman Miller:

Enclosed is an original and thirteen copies of the Direct Testimony of Steve Brown of the Consumer Advocate and Protection Division of the Office of the Attorney General. Kindly file the attached in this docket. By copy of this letter, we are serving all parties of record. If you have any questions, please feel free to contact me. Thank you

Sincerely,

A handwritten signature in dark ink, appearing to read "T. Phillips", written over a horizontal line.

Timothy C. Phillips
Senior Attorney General
(615) 741-8700

Enclosures

cc: All Parties of Record

77487

LATE FILED

CERTIFICATE OF SERVICE

I hereby certify that on July 30, 2004, a true and exact copy of the foregoing document has been sent to the following via method indicated below:

Via First class U.S. mail and facsimile

Joe A. Conner

Baker, Donelson, Bearman & Caldwell, P.C.

1800 Republic Centre

633 Chestnut Street

Chattanooga, Tennessee 37450-1800

Via Hand Delivery

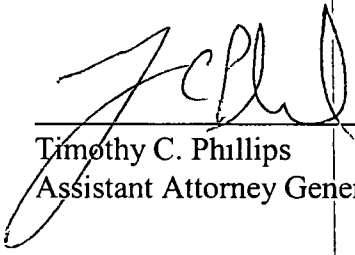
Randal Gilliam

Office of Legal Counsel

Tennessee Regulatory Authority

460 James Robertson Parkway

Nashville, Tennessee 37243-0505



Timothy C. Phillips
Assistant Attorney General

Before the

TENNESSEE REGULATORY AUTHORITY

**IN RE: UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY
CORPORATION COMPANY, INCENTIVE PLAN ACCOUNT (IPA) AUDIT**

DOCKET NO. 01-00704

**DIRECT TESTIMONY
OF
STEVE BROWN**

July 30, 2004

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

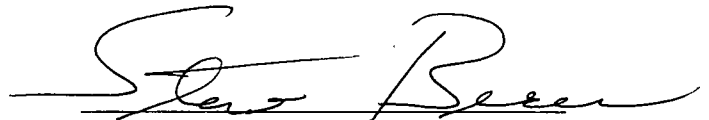
IN RE:

UNITED CITIES GAS COMPANY, a
Division of ATMOS ENERGY
CORPORATION COMPANY,
INCENTIVE PLAN ACCOUNT (IPA)
AUDIT

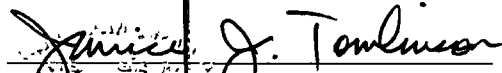
DOCKET NO. 01-00704

AFFIDAVIT

I, Steve Brown, for the Consumer Advocate and Protection Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate and Protection Division.


STEVE BROWN
Economist

Sworn to and subscribed before me
this 29th day of July, 2004.


NOTARY PUBLIC

My commission expires:

7/21/2007

I. Introduction

Q_1. Please state your name.

A_1. Steve Brown.

Q_2. Where do you work and what is your job title?

A_2. I am an Economist in the Consumer Advocate and Protection Division, Office of the Attorney General.

Q_3. What are your responsibilities as an Economist?

A_3. I review companies' petitions for rate changes and follow the economic conditions that affect the companies.

Q_4. What experience do you have regarding utilities?

A_4. In 1995 I began work as an economist in the Consumer Advocate and Protection Division (CAPD) of the Attorney General's Office. I have also appeared as a witness for CAPD in several cases before the Tennessee Regulatory Authority (TRA). From 1986 to 1995 I was employed by the Iowa Utilities Board as Chief of the Bureau of Energy Efficiency, Auditing and Research,

and Utility Specialist and State Liaison Officer to the U.S. Nuclear Regulatory Commission. From 1984 to 1986 I worked for Houston Lighting & Power as Supervisor of Rate Design. From 1982 to 1984 I worked for Arizona Electric Power Cooperative as a Rate Analyst. From 1979 to 1982 I worked for Tri-State Generation and Transmission Association as Power Requirements Supervisor and Rate Specialist. Since 1979 my work spanned many issues including cost of service studies, rate design issues, telecommunications issues and matters related to the disposal of nuclear waste.

Q_5. What is your educational background?

A_5. I have an M.S. in Regulatory Economics from the University of Wyoming, an M.A. and Ph.D. in International Relations with a specialty in International Economics from the University of Denver, and a B.A. from Colorado State University.

Q_6. Dr. Brown, have you authored any articles relating to your profession?

A_6. Yes, my articles have appeared in Public Utilities Fortnightly.

Q_7. Are you and have you been a member of any professional organizations, Dr. Brown?

1 A_7.

Yes, I am a past member of the NARUC Staff Committee on Management Analysis, a past trustee of and a member of the Board for the Automatic Meter Reading Association, and a current member of the National Association of Business Economists.

8 Q_8.

Have you studied mathematics and statistics as part of your education?

11 A_8.

Yes.

13 Q_9.

Dr. Brown, do you use mathematics and statistics in combination with economics as part of your profession?

17 A_9.

Yes.

19 Q_10.

What were you asked to do in this case?

21 A_10.

I was asked to form opinions on two issues relating to the Performance Based Ratemaking (PBR) program of Atmos (the Company):

1) Whether the TRA's final order of August 16, 1999 in TRA Docket No. 97-01364, "Application Of United Cities Gas To Establish An Experimental Performance-Based Ratemaking Mechanism," directly or implicitly recognized and approved the so-called "FERC Maximum Rate" as a means for calculating the income Atmos receives through the PBR;

2) Whether the PBR should be amended to recognize and approve the so-called "FERC Maximum Rate" as a means for calculating the income Atmos should receive through the PBR.

II. The "Maximum FERC Rate" Is Not A Part Of The PBR And Should Not Be A Part Of The PBR

Q_11. Are you knowledgeable regarding the PBR?

A_11. Yes.

Q_12. What is the basis of your knowledge?

A_12. My knowledge is based on my work with the CAPD. As staff of CAPD I have followed and analyzed the PBR since its inception in March 1995. From that time until now I have testified in every contested case the TRA convened to determine the merit of the PBR and its implementation.

The PBR is prospective by definition in the sense that "performance based ratemaking" operates through carefully determined formulas which are benchmarks representing the current and future state of the market, not the market's historical condition. The TRA determined that such

1 formulas gave the PBR an "automatic"
2 quality to penalize and reward the
3 Company:

4
5 *"The Tennessee Regulatory Authority has the statutory power to*
6 *approve a performance-based incentive mechanism which*
7 *automatically penalizes or rewards the public utility for its*
8 *performance in procuring natural gas that it sells to its*
9 *customers"* [Phase Two Order, page 6]

10
11 *"The proposal was designed to create an incentive to perform*
12 *better than... the market and to penalize the Company [for] ... a*
13 *price of gas above the pre-defined benchmarks."* [Phase Two
14 *Order, page 2]*

15
16
17 Therefore, the risk of penalty or loss is
18 fundamental to the PBR. Nothing in the PBR
19 allows the Company to change, add to, or
20 withdraw the pre-defined benchmarks,
21 otherwise the Company changes the risk-
22 measures in the PBR. The Company cannot
23 unilaterally modify or amend the PBR:

24
25 *"United Cities Gas Company is authorized to operate under the*
26 *[PBR] ... until the mechanism is either (a) terminated at the end of*
27 *Plan year by not less than ninety (90) days notice by United Cities*
28 *to the Authority, or (b) the PBR mechanism is modified, amended,*
29 *or terminated by the Authority."* [Phase Two Order, page 26]
30

Q_13.

In your opinion does the TRA's final order of August 16, 1999 in TRA Docket No. 97-01364 directly or implicitly allow Atmos to use "FERC Maximum Rate" to calculate the income Atmos receives through the PBR?

A_13.

No. In my opinion the final order neither directly nor implicitly allows the Company to use the "FERC Maximum Rate" to calculate the PBR's payments to Atmos. Nowhere in the entire record is there mention of the "FERC Maximum Rate."

Based on the record, my opinion is that the PBR is a substitute for the TRA's enforcement of the requirements of Section 1220-4-7.05 of the TRA's Purchased Gas Adjustment Rules titled "Audit of Prudence of Gas Purchases." My professional opinion as an economist is that the PBR is a "ratemaking." My professional opinion is that the TRA intended to assure that the PBR provides just and reasonable rates by strictly defining the PBR's implementation according to an index where the index is between the minimum and maximum prices of the market, and where the index is the PBR's tool to separate gain from loss. The PBR does not allow the "FERC maximum price" or any maximum price to be a basis for the calculation of the PBR's payments to Atmos.

Therefore, the Company errs when it claims that the "FERC maximum price" is included in the PBR. The "FERC Maximum Rate" has no risk-taking element for Atmos because there is no such thing as a price higher than the maximum price. Use of the "FERC Maximum Rate" contradicts the Authority's clear policy that the incentive program be conditioned by the Company's gains and losses, rather than being conditioned solely by gains.

Q_14.

What evidence in the record indicates the PBR is a ratemaking?

A_14.

The record shows the TRA applying the "just and reasonable" ratemaking standard to the PBR and determining that the prudence reviews should be waived. Chairman Greer cross-examined Atmos witness James Harrington:

"Q. If this plan is denied, how would you suggest that the TRA determine the company's purchasing gas at just and reasonable rates?"

A. Let me just make sure I understand the hypothetical. You're saying there's no incentive plan?"

Q. Yeah.

A. But the Woodward contract exists or doesn't exist?"

1 *Q. Well, if United Cities' plan is denied, how would the TRA*
2 *determine if the company is purchasing gas at just and reasonable*
3 *rates?*

4
5 *A. If you don't employ an incentive program, the other existing*
6 *mechanism is through a prudence review process " [Transcript,*
7 *Friday, March 27, 1998 Volume II, page 517, lines 10-25]*

8
9 Thus, the Authority's Phase Two Order waived
10 prudence reviews of Atmos:

11
12 *"For each plan year in which this Performance-Based*
13 *Ratemaking Mechanism is in effect, the requirements of Section*
14 *1220-4-7.05 of the Purchased Gas Adjustment Rules of*
15 *the Authority entitled 'Audit of Prudence of Gas Purchases are*
16 *hereby waived.' " [Phase Two Order, page 27]*

17
18 In addition, the TRA found in its Phase
19 One Order:

20
21 *"United Cities has the burden to prove that any and all changes in*
22 *rates are just and reasonable under Tenn Code Ann. §65-5-*
23 *203(a) " [Phase One Order, page 29]*

24
25 The testimony of Mr. Frank Creamer, a witness
26 in Docket 97-01364, confirms that the Company's
27 understanding of the PBR is that its terms had
28 to be established before the PBR could be
29 implemented:
30

1 *"But that's the point of the PBR It's to establish a target against*
2 *which the company will be judged next year, the year after, and the*
3 *year after that. So it makes it clear for everybody to understand*
4 *and see how rewards are being earned, how penalties are being*
5 *absorbed, and the standards against which gas purchase*
6 *prudencies will be measured against "* [Transcript, Friday, March
7 *27, 1998 Volume II, page 477, lines 7-14]*

8
9 However, the Company has never established
10 that the "FERC Maximum Rate" is a TRA-
11 approved standard or TRA-measure of "gas
12 purchase prudencies" or that the "FERC
13 Maximum Rate" embodies or facilitates the
14 PBR's establishment of just and reasonable
15 rates.

16
17 Q_15. **In your opinion would the "FERC Maximum**
18 **Rate" provide just and reasonable rates**
19 **through the PBR?**

20
21 A_15. No. In my opinion the "FERC Maximum Rate" would
22 not provide just and reasonable rates through
23 the PBR and therefore be properly included in
24 the PBR. "Just and reasonable rates" are
25 achieved in the PBR through risk-taking by the
26 Company, where risk is defined by a market
27 index between the market's maximum and minimum
28 prices, exactly as the TRA staff judged in
29 Docket 97-01364:
30

1 *"A. I see your question. United Cities, prior to the adoption of the*
2 *incentive plan, was actually able to, quote, beat the market,*
3 *unquote. For every winner in the market there must be a loser.*
4 *That's the whole idea of the market index, that it comes back to an*
5 *average price that everyone is paying." [Deposition of William H.*
6 *Novak, Monday, March 23, 1998, page 91 lines 12-13]*

7
8 Staff's opinion on this point is similar to the
9 opinion of the Company's witness, Mr. James
10 Harrington:

11
12 *"For an index price to be an accurate measure of the market*
13 *price, some purchases will be above the index and some will be*
14 *below." [Direct Testimony of James Harrington, page 24 lines 1-2,*
15 *Docket 97-01364]*

16
17
18 The "FERC Maximum Rate" does not expose Atmos
19 to penalty, risk, and the "potential-of-loss"
20 because Atmos can never make purchases above
21 the maximum rate. Therefore, no maximum rate
22 can be a part of the PBR, which can be properly
23 implemented only through an index, as Mr.
24 Harrington describes, or an average, as Mr.
25 Novak describes.

26
27 Q_16.

28 **In your opinion, is the "potential-for-**
29 **loss" or penalty a core principle of the**
30 **PBR?**

31 A_16.

32 Yes. In my opinion, penalty or the
33 "potential-for-loss," is a core principle
34 of the PBR because the Authority's clear
 policy is that the incentive program be

1 measured by the Company's gains and
2 losses, rather than being measured solely
3 by the Company's gains.
4

5 Consider the Authority's orders in Docket 97-
6 01364:
7

8 *"The proposal [PBR] was designed to create an incentive for*
9 *United Cities to perform better than the market and to penalize the*
10 *Company if its acquisition of gas supplies resulted in a price of gas*
11 *above the pre-defined benchmarks " [Phase Two Order, pages 1-*
12 *2]*
13

14 *"The Tennessee Regulatory Authority has the statutory power to*
15 *approve a performance-based incentive mechanism which*
16 *automatically penalizes or rewards the public utility for its*
17 *performance in procuring natural gas that it sells to its*
18 *customers "[Phase Two Order, page 6]*
19

20 *"The gains and losses under the plan should be calculated on a*
21 *monthly basis rather than on a transaction basis "[Phase One*
22 *Order, page 29]*
23

24 *". the gains and losses to be derived from the mechanism are to*
25 *be accounted for " [Phase Two Order, page 28].*
26

27 Mr. Harrington testified that the PBR:
28

29 *"will provide United Cities with an incentive to buy below*
30 *prevailing market price and will penalize if its purchases exceed*
31 *the market price " [Direct Testimony of James Harrington, page*
32 *20 lines 3-8, Docket 97-01364]*
33

1 Mr. Harrington's emphasis on penalty was echoed
2 by the opinion of Mr. Senter, the Company's
3 policy witness. He testified that penalties
4 were necessarily an integral part of the PBR:
5

6 *"If we can save our customers money on the cost of gas, we will*
7 *be rewarded; if we fail, we will be penalized. Either way, the*
8 *company should be rewarded or penalized based upon its*
9 *performance "* [Transcript, Tuesday, March 31, 1998 Volume III,
10 *page 574, lines 2 -6]*
11

12
13 Mr. Creamer further confirms that risk-taking
14 is a central feature of the incentive plan. In
15 cross-examination by the Consumer Advocate Mr.
16 Creamer testified:
17

18 *"The intent of the incentive program is to provide rewards to*
19 *encourage the company to take greater risk in purchasing gas*
20 *leading to benefits "* [Transcript, Thursday, March 26, 1998
21 *Volume I, page 76, lines 3-6].*
22

23 And
24

25 *"So what I observed in interviewing United Cities Gas is, tell me*
26 *what you're doing differently in terms of behaviors, not process,*
27 *but in terms of behaviors in how you're looking at buying gas. Are*
28 *you taking more risk? Are you looking to, in one case, incur a*
29 *higher-than-index price for gas in order to earn a benefit in a*
30 *lower-than-index purchase of gas a week later or two weeks later?*
31 *That's what we're trying to get at in terms of an incentive*
32 *program "*
33

34 *"Q And so, you say they're taking more risks?*

1
2 *A Yes." [Transcript, Thursday, March 26, 1998 Volume I, page*
3 *77, lines 16-25 and page 78, lines 8-9].*
4

5 In redirect examination by Atmos Mr. Creamer
6 was asked and testified about the built-in
7 penalty aspect of the PBR:
8

9 *"Q. Mr. Williams also asked you some questions about basis*
10 *points and rate of return on equity and what the staff*
11 *recommended in that case. You understand that the way this plan*
12 *works is if United Cities does not do a very good job of purchasing*
13 *gas that it can incur a penalty and the result of that penalty would*
14 *essence be a lowering of their authorized rate of return?"*
15

16 *"A The penalty would be a lowering of their rate of return?"*
17

18 *"Q. Yes Based upon the answer that you gave to Mr. Williams*
19 *about the fact that if they were awarded, that, in essence, would*
20 *increase their rate of return?"*
21

22 *"A. Would increase their overall return -- or decrease their*
23 *overall return, what you said. But there would be no Commission*
24 *action that would penalize them. The plan itself would take care of*
25 *that.*
26

27 *"Q It's an automatic penalty?"*
28

29 *"A Yes " [Transcript, Thursday, March 26, 1998 Volume I, page*
30 *285, lines 6-25 and page 286, line 1]"*
31

1 However, there is no possibility of the TRA
2 automatically penalizing Atmos with a lower
3 rate of return if the "FERC Maximum Rate" were
4 incorporated into the PBR.

5
6 Q_17.

**In its proposed Transportation Index
Factor (TIF), how is the Company using and
justifying the "FERC Maximum Rate" to
calculate the PBR's payments to Atmos?**

7
8
9
10
11 A_17.

The Company's method of calculation and
the justification for the method are
clearly stated in Mr. Mark Thessin's
affidavit of October 21, 2002. According
to Mr. Thessin, the PBR defined
transportation-contract-savings as the
difference between the "FERC Maximum Rate"
for transportation and the actual
transportation rate the Company pays.

12
13
14
15
16
17
18
19
20
21 For example, in his affidavit at paragraph
22 10 Mr. Thessin says:

23
24 " UCG had successfully negotiated discounted rates for a
25 substantial portion of its transportation contracts. In prior years
26 UCG's transportation contracts were priced at the maximum rate
27 permitted by [the FERC]. . the savings from those discounted
28 transportation contracts . totaled \$1,160,050 ."
29

1 The Company's claim that it should be
2 rewarded solely on the basis of past
3 performance in comparison to current
4 performance completely contradicts the
5 testimony of its witness, Mr. Harrington,
6 who rejected past performance as measure:
7

8 *"But UCG's past performance was not the market price then and is*
9 *not the market price now "* [Transcript, Friday, March 27, 1998
10 *Volume II, page 512, lines 6-7]*
11

12 At Paragraph 13 Mr. Thessin says further:
13

14 *"UCG explained that the transportation discounts would be*
15 *considered 'avoided transportation costs' under the PBR UCG*
16 *would be entitled to share in those savings "*
17

18 However, the Company has misinterpreted
19 the PBR's meaning of "avoided
20 transportation costs." The PBR's intent is
21 to remove the effects of the
22 transportation price from the gas
23 commodity price, so that gas commodity
24 prices from different parts of the country
25 can be compared to the commodity market
26 indices. The PBR was never intended to be
27 implemented as the Company has done so.
28

29 For example, the TRA staff in its "Compliance
30 Audit Report of United Cities Gas Company's
31 Incentive Plan Account" of April 10, 2002,
32 rejects the Company's use of the "FERC Maximum
33 Rate" in the PBR. The Company's response shows
34 it abandoning the PBR's market indices:

1
2
3 *"The absence of published benchmarks providing comparative*
4 *analysis on discounted transportation rates should not preclude*
5 *the Staff from including transportation discounts in the PBR*
6 *mechanism "* [Compliance Audit Report of United Cities Gas
7 *Company's Incentive Plan Account, Docket No. 01-00704, April*
8 *10, 2002, page 13-14]*

9 Thus the Company is evading the risk-taking
10 measurement embodied in the PBR's use of the
11 widely published market indices. They provide a
12 measure of purchasing activity in comparison to
13 a real market. The "FERC Maximum Rate" bypasses
14 the essential measures described by Mr.
15 Harrington:

16
17 *"Inside F.E.R.C.'s Gas Market reports has been reporting in the*
18 *same format since March 1986. The survey sample comprises more*
19 *than 350 sources [CAPD Emphasis] The sample is composed*
20 *almost entirely of large and small gas producers, pipeline-*
21 *affiliated and non-affiliated marketers, distributors and end-users.*
22 *Prices are reported for actual spot-gas sales agreements, not*
23 *offers or bids "*

24
25 *"Intelligence Press, Inc , publishers of Natural Gas Intelligence*
26 *("NGI") gathers the data used in settling prices via a daily*
27 *telephone survey of industry representatives. The source base*
28 *consists of over three hundred participants [CAPD Emphasis]from*
29 *all sectors of the natural gas industry and its customers. By*
30 *obtaining quotes from a large sampling of producers, marketers,*
31 *intrastate pipelines, industrial end-users, and utilities, NGI*
32 *increases the likelihood that the prices appearing in the newsletter*
33 *more closely approach the true population average in an objective*
34 *manner "*

1
2 *"The NYMEX gas futures index is a major source for discovering*
3 *the US gas reference price. Market participation by a broad*
4 *spectrum of the energy industry [CAPD emphasis] helps ensure*
5 *that all available information on supply and demand is*
6 *incorporated in the price determination process. Gas futures*
7 *prices are determined by free competition among traders who*
8 *announce, by open outcry, their desire to buy or sell a certain*
9 *number of contracts at a certain price The forces of many pricing*
10 *factors ensure that futures prices reflect the true market value of*
11 *the underlying gas commodity and are transparent to the*
12 *marketplace at large."*

13
14 *"Pasha Publications, Inc. publishers of Gas Daily surveys scores*
15 *of respondents per day and a few hundred during bid week*
16 *[CAPD emphasis] to produce ranges and indices. Gas Daily*
17 *surveys the complete spectrum of the industry, from wellhead to*
18 *burnertip, to acquire data. The Gas Daily price team talks to*
19 *major producers and all sizes of independents and marketers from*
20 *the largest national players to the smallest niche players and local*
21 *distribution companies, regardless of size, power companies,*
22 *congenerators and end-users " [Direct Testimony of James*
23 *Harrington, pages 21-22]*

24
25
26 That the Company wants to jettison these
27 indices and be judged by its own historical
28 performance is a sure sign that the "FERC
29 Maximum Rate" is not a part of the PBR and that
30 such a rate should not be a part of the PBR.
31 This concludes my testimony at this time.
32
33

1 BEFORE THE TENNESSEE REGULATORY AUTHORITY

2

3

4 IN RE:

5 APPLICATION OF UNITED CITIES GAS)
6 TO ESTABLISH AN EXPERIMENTAL) Docket No.
7 PERFORMANCE-BASED RATEMAKING) 97-01364
 MECHANISM)

8

9

10 TRANSCRIPT OF PROCEEDINGS

11 Tuesday, March 31, 1998

12 VOLUME III

13

14

15 APPEARANCES:

16

17 For United Cities Gas: Mr. James G. Flaherty
 Mr. John L. Baugh

18

19 For Consumer Advocate Mr. L. Vincent Williams
20 Division: Mr. Vance L. Broemel

21

22

23

24

25

Reported By:
Susan D. Delac, CCR

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16 MR. FLAHERTY: Well, Your Honor,
 17 Mr. McDowell was up here twice; they could have asked
 18 him those questions at that time. I don't know why
 19 they didn't ask those questions. If they thought it
 20 was a relevant issue, they should have asked those
 21 questions at that point.

22 DIRECTOR KYLE: I would like you to
 23 answer why you didn't pursue this line of questioning
 24 when he was available for cross.

25 MR. WILLIAMS: This line of

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1 questioning came up during the Chairman's questioning
 2 of Mr. McCormac, so it was after Mr. McDowell. And so
 3 it didn't --

4 DIRECTOR KYLE: Has he left? Has
 5 Mr. McDowell left?

6 MR. WILLIAMS: -- the answer was not
 7 relevant until it was made relevant by the course of
 8 the questioning.

9 DIRECTOR KYLE: Has he left?

10 MR. FLAHERTY: Director Kyle, I
 11 specifically made a request at the break if
 12 Mr. McDowell could be excused.

13 CHAIRMAN GREER: He asked for
 14 Mr. McDowell and Mr. Woodward both.

15 MR. FLAHERTY: Yes.

16 DIRECTOR MALONE: According to
 17 General Williams, that was before the Chairman made

18 his question. Mr. Flaherty, are you stating a
19 specific objection to the request of the Consumer
20 Advocate regarding this deposition?

21 MR. FLAHERTY: Yes.

22 DIRECTOR MALONE: Well, I have a
23 suggestion. My suggestion is twofold; one, to remind
24 the parties that generally depositions are for the
25 purpose that depositions are generally used. I mean,

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1 if you walked in here today, Consumer Advocate, with a
2 box full of 2,000 pages of depositions, and you did
3 not use those depositions to impeach, that imposes
4 quite a burden on the Authority.

5 Having said that for future
6 reference, since they have stated that this was in
7 response to questioning of Mr. McCormac after
8 Mr. McDowell has departed, I would ask Mr. Flaherty if
9 he would consider withdrawing his objection.

10 MR. FLAHERTY: Maybe as a compromise,
11 if there's specific pages within the deposition that
12 answer the question that was raised by Chairman Greer.

13 DIRECTOR MALONE: Perhaps,
14 General Williams, either you or Mr. Broemel can peruse
15 the deposition while Dr. Brown is summarizing, and
16 give us those pages later.

17 MR. BROEMEL: We can do that. In
18 fact, he's already written them out, so we're fine.

19 CHAIRMAN GREER: Dr. Brown, I swore
20 you in in the first phase, so please consider yourself
21 still under oath. You're still sworn.

22 DR. BROWN: Thank you.

23 ///

24 ///

25 ///

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1 STEPHEN N. BROWN,
2 was called as a witness, and having been previously
3 sworn, was examined and testified as follows:
4

5 DIRECT EXAMINATION

6 BY MR. BROEMEL:

7 Q. Would you state your name for the record.

8 A. Stephen N. Brown.

9 Q. And by whom are you employed?

10 A. The Consumer Advocate Division of the
11 Attorney General's office.

12 Q. Now, it's my understanding you've already
13 given testimony in Phase I of this proceeding?

14 A. Yes.

15 Q. Now, for Phase II, you've prepared, I
16 believe, direct testimony and supplemental testimony?

17 A. Yes.

18 Q. And I've already given those to the court
19 reporter. Do you adopt both the direct and
20 supplemental testimony?

21 A. I do.
22 Q. And do you have any corrections?
23 A. Yes. I have one correction in my direct
24 testimony on page 17 of 23. The second question, I
25 refer to Mr. Harrison, it should be Mr. Harrington.

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1 And that's my only change.
2 Q. Do you adopt the testimony with those
3 corrections?
4 A. Yes.
5 Q. And I am referring to both the direct and
6 the supplemental.
7 A. Yes.
8 MR. BROEMEL: I'd like to move that
9 they be entered into the record at this time.
10 CHAIRMAN GREER: Without objection,
11 so ordered.
12
13 (Prefiled testimony of Dr. Stephen N. Brown is
14 inserted into transcript as if read.)
15
16 (Balance of this page is left blank intentionally.)
17
18
19
20
21

22

23

24

25

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1 BY MR. BROEMEL:

2 Q. Would you please give us a summary of your
3 testimony. And by that, I use both direct and
4 supplemental.

5 A. All right. The first major point of my
6 direct testimony is that the Woodward Marketing
7 contract appears to have resulted in United Cities'
8 purchasing higher cost gas than otherwise would be the
9 case.

10 It appears that there is a, quote, a
11 conceptual hole in the index and in this proposition.
12 For example, eight cents below the index on one
13 pipeline may be higher than eight cents below the
14 index on another pipeline.

15 My findings show that there's a
16 considerable shift from year one to year two in the
17 source of United Cities' gas purchases. That shift
18 went from Tennessee Pipeline, which is a comparatively
19 lower cost pipeline, to Columbia Gulf
20 Gas which is a higher cost gas pipeline. Even though
21 the shift occurred, the idea of eight cents below the
22 index would not capture that shift.

23 I've also found that based on the data we
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24 were provided by Woodward, that the published indices
25 tend to overstate the cost of gas. Schedule 3, which

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1 is attached to my testimony, shows that in February of
2 1997, 41 percent of the purchases that Woodward made
3 on the Tennessee Gas Pipeline were below the minimum
4 published price for Tennessee Pipeline, minimum FERC
5 index price for Tennessee Pipeline.

6 My other finding based on the evidence is
7 that Woodward Marketing appeared to be losing money on
8 the sales to United Cities, but those losses did not
9 mean that the consumers were receiving the lowest
10 prices.

11 I further concluded that there was a
12 probability that Woodward Marketing has, can, or will,
13 earmark low cost gas for customers other than United
14 Cities. I further concluded that Woodward Marketing
15 is profitable in its overall operations based upon its
16 FCC filing. And, finally, I conclude that because of
17 the profitability showing the FCC report, that the
18 data supplied by the company to us is erroneous.

19 The heart of my findings lie in
20 Schedules 1 and 2. Schedule 1 shows United Cities'
21 purchases by pipeline for the first 12 months of this
22 period, which would be from April 1995 through March
23 1996. And it also shows comparison with the second
24 year. That's where the shift from Tennessee Gas

25 Pipeline as the source to Columbia Gulf Pipeline is

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1 shown.

2 And then in Schedule 2, based upon
3 Woodward's information, I found that, according to the
4 information, Woodward was selling more gas on Columbia
5 Gulf Pipeline to United Cities than, in fact, Woodward
6 had purchased. And I further concluded that based
7 upon the information given to us, that the Woodward
8 contract predated the PBR, and that the PBR gave the
9 appearance of being a response to the contract and to
10 the formation of the merged company rather than the
11 other way around.

12 And then my conclusion with regard to NORA
13 is very similar to my conclusions in Phase I, that in
14 16 out of 24 months from April 1995 through March
15 1997, the NORA price was lower than any of the -- than
16 the minimum published price on the Tennessee Gas
17 Pipeline. And, in addition, because the contract
18 predates the PBR, I recommend that NORA be excluded
19 from the PBR as well. That concludes my summary.

20 MR. BROEMEL: The witness is
21 available for cross-examination.

22 CHAIRMAN GREER: Mr. Flaherty.

23 ///

24 ///

25 ///

1 CROSS-EXAMINATION

2 BY MR. FLAHERTY:

3 Q. Dr. Brown, good afternoon.

4 A. Good afternoon.

5 Q. Let me start by asking a question about
6 your Schedule 7 to your direct testimony.

7 A. Yes. I have it.

8 Q. That's the October 19th, 1994, agreement
9 between Woodward Marketing Inc. and UCG Energy to form
10 the L.L.C.; is that correct?

11 A. Yes.

12 Q. And let me direct your attention to page 2
13 of your schedule, and paragraph 2 which is entitled
14 "Formation of L.L.C. and Transfer of Assets." Do you
15 see that?

16 A. Yes.

17 Q. It is your understanding that under your
18 review of that paragraph that UCG Energy was to
19 contribute certain gas contracts relating to its gas
20 marketing business known as United Cities Energy
21 Marketing to the formation of this L.L.C.?

22 A. Yes, that's my understanding.

23 Q. Did the Consumer Advocate ever ask the
24 president of Woodward Marketing L.L.C. what gas
25 contracts UCG Energy contributed to the L.L.C.?

- 1 A. I don't recall.
- 2 Q. Do you know which gas contracts United
- 3 Cities Energy Marketing contributed to the L.L.C.?
- 4 A. It's my understanding that all of the
- 5 contracts were transferred.
- 6 Q. And what's the basis for your
- 7 understanding of that?
- 8 A. Prior conversations that might have come
- 9 up in a deposition, that might have come up in
- 10 response to data requests or might have come up in the
- 11 conference meetings -- if that's the right word for
- 12 it -- that were held here with regard to various data
- 13 requests and so forth.
- 14 Q. Can you point to any evidence that's been
- 15 included in the record that would suggest that all gas
- 16 contracts were transferred to L.L.C.?
- 17 A. I have nothing specific.
- 18 Q. Let me direct your attention to the top of
- 19 page 3 of your direct testimony. And the answer to
- 20 that, at the top of that page you state that you were
- 21 asked to form an opinion with regards to United Cities
- 22 Gas purchasing practices from April of 1996 through
- 23 March of 1997; is that correct?
- 24 A. Yes.
- 25 Q. In forming that opinion, did you have any

1 discussions with Mr. McDowell or his gas supply staff
2 about United Cities' transportation contracts with its
3 interstate pipelines?

4 A. No.

5 Q. Do you understand that as a result of
6 Order 636, United Cities was assigned a capacity on
7 the various interstate pipelines which requires United
8 Cities to pay reservation or demand charges for that
9 capacity?

10 A. Yes.

11 Q. And that some of those capacity contracts
12 run through the year 2000?

13 A. No. I don't know what the term is.

14 Q. Did you ask to review those gas
15 transportation contracts that United Cities has with
16 these interstate pipelines?

17 A. No.

18 Q. Could you have?

19 A. I could have. However -- the answer is,
20 yes, I could have. However, the data that was
21 provided to me enabled me to make an evaluation of the
22 gas purchasing practices of United Cities from
23 April 1996 through March 1997.

24 Q. And would you agree with Mr. McCormac,
25 though, that part of that gas purchasing analysis

1 would include the cost that United Cities pays for
2 transportation capacity?

3 A. What did Mr. McCormac -- I don't -- I'd
4 say -- I have to say no because I don't recall that
5 Mr. McCormac said that. Did he just say it here or
6 was it in his testimony?

7 Q. Well, I think the record will speak for
8 itself. But I think what he indicated to the TRA is
9 that commodity cost is just one part of this, that you
10 also need to look at the transportation cost
11 associated with getting that gas to market.

12 And my specific question to you is, could
13 you have reviewed United Cities' transportation
14 contracts which it has with these interstate
15 pipelines?

16 A. Yes, we could have. And, in fact,
17 Mr. McDowell did provide us transportation costs for
18 two pipelines in Exhibit RWM-R1 of his rebuttal
19 testimony which he then withdrew.

20 Q. And the yellow sheet that your attorney
21 filed as an exhibit in this case, do you understand
22 what information is contained on that sheet?

23 A. I believe --

24 CHAIRMAN GREER: Wait a minute. Wait
25 a minute.

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1 DIRECTOR KYLE: Can we just stop. I
2 may even want her to read those last two questions

3 back. And then can we stop?

4 CHAIRMAN GREER: I'm a little
5 confused.

6 DIRECTOR KYLE: Or can you repeat the
7 last two questions that you asked about that?

8 CHAIRMAN GREER: Would you back up
9 and take his last two questions and his responses.

10 (The portion of the testimony
11 beginning on page 792, line 7, was read by the court
12 reporter.)

13 (Off-the-record discussion.)

14 MR. FLAHERTY: I will continue with
15 that line of questioning.

16 CHAIRMAN GREER: Clear that up.
17 Because how could they provide them and then not use
18 them and then they -- or then use them and then it be
19 withdrawn.

20 BY MR. FLAHERTY:

21 Q. Dr. Brown, the contracts that I was
22 specifically referring to are the actual contracts
23 that United Cities has with these interstate
24 pipelines. Were those physical contracts that happens
25 with each of these interstate pipelines that

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1 Mr. McDowell talked to you? Were those provided to
2 you?

3 A. Not to my knowledge, no.

4 Q. And what you were previously referring to
5 was the exhibit that was attached to Mr. McDowell's
6 rebuttal testimony; is that correct?

7 A. Yes, which has transportation charges on
8 it for two pipelines, Columbia Gulf and Tennessee Gas.

9 Q. And you indicated, I believe, that you
10 thought that that was withdrawn. Is it your
11 understanding that Mr. McDowell, when he testified
12 here today, revised that rebuttal exhibit?

13 A. No, sir. It's my understanding he
14 replaced it totally.

15 Q. And that's what you're referring to as the
16 document that would have been withdrawn?

17 A. Well, I -- the answer is yes, but let me
18 qualify my answer. Would have been withdrawn. It
19 appears to me it is withdrawn because his revised
20 exhibit is 100 percent different than what he attached
21 to his rebuttal testimony. And his revised exhibit
22 occurred right after we deposed Mr. Woodward, the very
23 next day. And we asked him questions about -- we
24 asked Mr. Woodward questions about this exhibit. And
25 the very next day Mr. McDowell withdrew it.

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1 CHAIRMAN GREER: Is that exhibit
2 Woodward Exhibit No. 3?

3 THE WITNESS: Yes. Yes, that's it.

4 DIRECTOR MALONE: Does that exhibit
5 contain all the transportation cost information?

6 THE WITNESS: To the left-hand side,
7 six to eight lines down you'll see a listing that says
8 transportation charges. And it says 5.63 cents per
9 MCF for Columbia and .0085 cents for Tennessee Gas
10 Pipeline. Those are all the transportation charges
11 that Mr. McDowell indicates that are on here. None of
12 the other charges on here have that same name. So my
13 conclusion is, yes, that refers to all the
14 transportation charges.

15 CHAIRMAN GREER: And you've had this
16 since the 24th day of March?

17 THE WITNESS: We've had this since it
18 was filed as rebuttal, I believe on the 16th or 18th.

19 DIRECTOR MALONE: The 16th, I
20 believe.

21 CHAIRMAN GREER: This exhibit was
22 filed dated 3/24 of '98.

23 THE WITNESS: This was Mr. McDowell's
24 exhibit that he filed on 3/16. Then in Mr. Woodward's
25 deposition, we asked him questions about this exhibit,

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1 and then on March 25th, this exhibit was withdrawn and
2 replaced with supposedly a revised exhibit. But the
3 revised exhibit is completely different than this.
4 And I address this issue in my supplemental testimony
5 that I filed on March 26th.

6 DIRECTOR MALONE: Does that revised

7 exhibit contain all the relevant transportation cost
8 information to which Mr. McCormac said that he would
9 have liked to have had?

10 THE WITNESS: I don't know, sir.
11 You're referring to the revised exhibit?
12 Mr. McDowell's revised exhibit that was filed on
13 March 25th at 4:30 p.m.?

14 DIRECTOR MALONE: Is that the exhibit
15 we're talking about, Mr. Flaherty?

16 MR. FLAHERTY: I believe the exhibit
17 he's talking about is the exhibit that was revised and
18 filed on March 24th.

19 THE WITNESS: March 25th at 4:30 p.m.
20 BY MR. FLAHERTY:

21 Q. Dr. Brown, do you recall during
22 Mr. Woodward's deposition when you were going over
23 that exhibit, that he couldn't understand what was
24 contained in that exhibit?

25 A. No, I don't recall that he could not

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1 understand what was in it.

2 Q. Your attorney asked him a number of
3 questions that he couldn't answer because he didn't
4 really understand what the exhibit showed?

5 A. I don't recall that. If you would refresh
6 my memory. I have his deposition here. If you could
7 point me to pages and lines.

8 DIRECTOR KYLE: Why don't we do that.
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9 MR. FLAHERTY: Okay.

10 DIRECTOR MALONE: Just to make sure

11 we're talking about the same thing, on March 24th,

12 revisions of certain pages of Mr. Woodward's prefiled

13 testimony was filed?

14 MR. FLAHERTY: That's correct.

15 DIRECTOR MALONE: Is that what we're

16 talking about or are we talking about revisions to an

17 exhibit?

18 MR. FLAHERTY: What we're talking

19 about is the revision that Mr. McDowell made to his

20 one exhibit that was attached to his rebuttal

21 testimony, RWM-1. That revision was made and was

22 prefiled on March 25th. And the explanation as to why

23 that change was made was given by Mr. McDowell this

24 morning when he took the stand.

25 DIRECTOR MALONE: Which doesn't

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1 change the fact that it was filed on March 26th.

2 MR. FLAHERTY: May I proceed?

3 DIRECTOR KYLE: I'm ready.

4 BY MR. FLAHERTY:

5 Q. Dr. Brown, during Mr. Woodward's

6 deposition, you asked him if he could provide to you

7 the maximum daily quantity under each of those

8 transportation contracts that United Cities had with

9 these five interstate pipelines; is that correct?

10 A. Yes, he was asked that.
 11 Q. And he provided that information to you,
 12 and I believe it has been marked as Exhibit 23 in this
 13 case; is that correct?
 14 A. Yes, it is.
 15 Q. Was there any reason why the Consumer
 16 Advocate, if it was concerned about the transportation
 17 cost paid by United Cities, couldn't have asked United
 18 Cities for the actual contracts that it had with these
 19 interstate pipelines?
 20 A. I'm sorry. Could you ask me again slower?
 21 Q. Is there any reason why the Consumer
 22 Advocate could not have asked United Cities for the
 23 actual contracts that United Cities had with these
 24 interstate pipelines?
 25 A. Well, yes. And let me qualify it. It

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1 goes back to the data that we were provided originally
 2 by the company. On a month-to-month basis, as part of
 3 this PBR plan, the company provided a listing each
 4 month of how much it bought by pipeline and the zone,
 5 the pipeline, and the supplier on that pipeline.
 6 In all those pieces of data month by month
 7 for 24 months, there was never a listing that said
 8 transportation charge, there was never a listing that
 9 said demand charge, there was never a listing that
 10 said reservation charge; it simply was a dollar
 11 figure. Now, in the sense that that wasn't there, I

12 guess it did not jump out at me that transportation
13 charges were particularly important.

14 However, to go back to Mr. McDowell's
15 exhibit that he withdraw, and you look at what he
16 labels as transportation charges, they are, in fact, a
17 very tiny portion of the overall cost. For example,
18 the commodity cost that he indicates on Columbia Gulf
19 is almost \$4, but the transportation charge is
20 5 1/2 cents. In Tennessee Gas Pipeline, the commodity
21 cost is about \$3.80, and the transportation charge is
22 only .0085 cents.

23 So in retrospect -- I want to pull all of
24 this together -- it seems as if transportation costs,
25 based on this stuff, is not very significant.

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1 Q. And when you're referring to the
2 transportation cost, you're just referring to the
3 commodity cost, you're not referring to the
4 reservation charge or the demand charge that are
5 contained in these contracts that United Cities has
6 with these interstate pipelines; is that correct?
7 A. Yes. And I'm referring to the lead given
8 to me by Mr. McDowell in his Exhibit RWM-R1 in which
9 he labels transportation charges as one small element
10 of the overall charges.
11 Q. And that RWM-R1 that you indicate was
12 withdrawn, that does include reservation charges. Do

13 you see that?

14 A. Yes, it does.

15 Q. And is it your understanding based upon
16 your understanding of the natural gas market that
17 interstate pipelines charge demand charges and
18 reservation charges for utilities to hold capacity on
19 their pipelines?

20 A. Yes, that's true.

21 Q. And that those costs are part of the cost
22 of supplying gas to the city gait?

23 A. Yes.

24 Q. And do you have knowledge as to whether or
25 not those charges, those demand charges or reservation

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1 charges would be contained either in the contract that
2 United Cities has with the pipeline or on file at the
3 FERC?

4 A. I suspect they'd probably be on file at
5 FERC.

6 Q. And the part that would be in the contract
7 specific between United Cities and the interstate
8 pipelines would contain the maximum daily quantity or
9 capacity that the utility has to pay for?

10 A. I'm sorry. Could you say the first part
11 again, please?

12 Q. Sure. The contract that United Cities has
13 with each of these interstate pipelines, would that
14 include the maximum daily quantity that United Cities

15 pays reservation charges and demand charges on?
16 A. It certainly should, yes.
17 Q. Did you have any discussions with
18 Mr. McDowell or his staff about United Cities Gas
19 storage capacity contracts it has with the interstate
20 pipelines?
21 A. No.
22 Q. Do you understand that United Cities has
23 has storage capacity on some of those pipelines?
24 A. According to what I heard Mr. McDowell
25 testify to today, yes.

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1 Q. And you understand that United Cities does
2 not have storage capacity on other pipelines?
3 A. Only according to what I heard today.
4 Q. And, again, those are questions that you
5 could have asked in the discovery in this case in
6 regard to forming an opinion as to United Cities Gas
7 purchasing practices?
8 A. Yes. But I'll qualify it as a very, very,
9 very weak yes. Because, to my knowledge, the
10 information that we received from the companies never
11 told how much they were putting back in storage each
12 month, how much they were taking out. Based on data
13 we received, we saw no MCF being injected or pulled
14 out, nothing. So it was never indicated by you that
15 it was a significant factor.

16 Q. Did you ever ask what amount of gas
17 storage capacity the L.D.C. had?

18 A. No.

19 Q. Do you understand that within the
20 constraints of these transportation capacity contracts
21 and storage capacity contracts that Mr. McDowell and
22 his staff developed what they considered to be an
23 optimum plan for the seven summer months and the five
24 winter months?

25 A. Yes. But let me qualify it. I really

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1 can't tell if it's optimum based upon this exhibit
2 that was submitted and then withdrawn because it has a
3 load factor of approximately 200 percent in that
4 month, January of 1977, and we know the load factor of
5 anything more than 100 percent is not physically
6 possible. So I can't relate the scheduling, this
7 optimal scheduling, to the demand constraints, the
8 transportation constraints you just mentioned.

9 Q. Did you ever sit down with Mr. McDowell or
10 his staff to ask them how he and his staff developed
11 this optimum summer and winter plan?

12 A. No.

13 Q. Did you ask any discovery requests about
14 how that plan is developed by Mr. McDowell and his
15 staff?

16 A. No.

17 Q. And you understood that that winter and

18 summer plan was directly referenced in the Woodward
19 contract and that somehow that Woodward contract was
20 tied to the winter and summer plans?

21 A. I would say, no, I did not know that right
22 off the bat, not until later.

23 Q. In reading the contract, there's a
24 reference in the contract to a winter plan and a
25 summer plan?

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1 A. I believe there is.

2 Q. Was there anything that precluded you from
3 sitting down to Mr. McDowell and his staff to ask them
4 questions about how they came up with a winter plan
5 and a summer plan?

6 A. Well, to the extent that we didn't know
7 about this until very, very late in the game, we were
8 precluded from it, yes. Once we found your SEC filing
9 for January 1995, and then we became aware that, in
10 fact, the Woodward contract was in existence as of
11 August 19 -- well, through I believe it was a staff
12 letter of August of 1996. At that point, sometime
13 after that time, the contract became a factor. And I
14 cannot remember when we got that contract. But I
15 recall that the ideas of summer and winter peaking and
16 planning didn't sink in until later in my mind.

17 Q. Do you recall Mr. McCormac indicating that
18 he at least heard about this contract between United

19 Cities and Woodward when he received the
 20 correspondence that Mr. Novak and Mr. Thessin had
 21 about the contract?
 22 A. Yes.
 23 Q. And that would have been back in August of
 24 '96?
 25 A. Apparently, yes.

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1 Q. Did you form any opinion as to the
 2 reasonableness of the winter or summer plan that
 3 Mr. McDowell and his staff developed as it related to
 4 the transportation and storage capacity constraints
 5 that they had under these contracts with the
 6 interstate pipelines?
 7 A. No. And neither was I in a position to.
 8 Q. Did you form any opinion as to whether a
 9 better plan could have been formed given the
 10 transportation and storage capacity contractual
 11 constraints with the interstate pipelines?
 12 A. Please ask me one more time, slowly.
 13 Q. Did you form any opinion as to whether or
 14 not there was a better plan that could have been
 15 formed given the transportation and storage capacity
 16 contractual constraints?
 17 A. With regard to Mr. McDowell's plan, his
 18 summer and winter plan, no, I think.
 19 Q. When you first started your investigation,
 20 you realized that United Cities had to have some type

21 of contractual arrangement with these interstate
22 pipelines to get gas to their city gates, didn't you?

23 A. Sure.

24 Q. And you understood that the transportation
25 cost associated with getting that gas to the city

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1 gates was a cost that would be included in the cost of
2 gas, didn't you?

3 A. Yes.

4 Q. Did you understand that Mr. McDowell and
5 his staff have the ability to modify their optimum
6 summer and winter plans if their forecast is off
7 during certain months?

8 A. No, I don't. Didn't know that.

9 Q. Do you recall either Mr. Woodward in his
10 deposition or Mr. McDowell indicating that he had the
11 ability under the Woodward contract that if his
12 forecast is off that he could modify the plan as
13 submitted to Mr. Woodward?

14 A. No, I don't. I recall Mr. Woodward saying
15 several times, I bill them according to what they
16 forecast. Five or six times he said that in his
17 deposition. I don't recall him saying they can modify
18 it, though, and tell me, and then I'll bill them
19 something different.

20 Q. Do you recall in your review of the --
21 well, did you review the gas purchase contract dated

22 April 1st, 1996, between United Cities and Woodward
23 Marketing L.L.C.?
24 A. Yes, I read it.
25 Q. Do you recall a provision in that contract

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1 which allows United Cities to modify the winter and
2 summer plan that is provided to Woodward?
3 A. I don't recall it, but I'm going to take
4 your word for it.
5 Q. Did you ever sit down with Mr. McDowell or
6 his staff and discuss why he or his staff decided to
7 modify their winter or summer plan that was submitted
8 to Mr. Woodward under that contract?
9 A. No, sir. I never called them and they
10 never called me; they never volunteered.
11 Q. I take it then that you didn't form an
12 opinion as to whether or not any of those
13 modifications to that winter or summer plan were
14 reasonable?
15 A. That's correct.
16 Q. Based upon your review of the gas purchase
17 contract dated April 1st, 1996, between United Cities
18 and Woodward Marketing L.L.C., do you understand how
19 that winter and summer plan that Mr. McDowell and his
20 staff put together is used under that contract?
21 A. No.
22 Q. Did you ever sit down and ask Mr. McDowell
23 or his staff how that summer or winter plan is used

24 under the Woodward contract?

25 A. No, I didn't. And he didn't volunteer

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1 that to me either.

2 Q. Did you ask Mr. Woodward during his
3 deposition as to how the summer and winter plan worked
4 in relation to that contract?

5 A. We may have. I don't recall. I know that
6 he discussed it.

7 Q. Do you recall what he discussed and how
8 that summer and winter plan are used under the
9 contract?

10 A. Not precisely; however, I recall the gist,
11 and I'll paraphrase. He told us that he billed off of
12 a forecast, and that he was given a plan and that he
13 worked from that. And I believe he gave us a copy of
14 the plan that he had received from Mr. McDowell. And
15 I think that may be an exhibit to the deposition.

16 Q. Did you ever ask Mr. McDowell in his
17 deposition how this plan relates to the Woodward
18 contract?

19 A. I don't recall. I wasn't present in his
20 deposition.

21 Q. Did you review his deposition?

22 A. Mm-hmm.

23 Q. Do you recall if he was asked that
24 question?

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25 0. Sure.

1 MR. FLAHERTY: Could you read the
2 question back.

3 (The question beginning on
4 page 809, line 19, was read by the court reporter.)

5 THE WITNESS: I don't agree. I don't
6 agree with that at all. For example, if you look at
7 Schedule 2 of my direct testimony, you'll see that I
8 went to great effort to compare United Cities'
9 purchases from Woodward by pipeline against Woodward's
10 purchases from its sources on its pipeline. And, in
11 fact, in Matrix G of Schedule 2, I found several
12 months that indicated that Woodward was selling more
13 to United Cities than it, in fact, had purchased on
14 pipelines.

15 However, in Mr. Woodward's
16 deposition, he's pointed out that where he gets his
17 gas is his business; in fact, he can buy it from one
18 pipeline and yet bill it to United Cities as if it
19 were purchased on another pipeline. Therefore, your
20 assertion, I do not agree with. I couldn't have
21 raised all those points because I was obviously
22 operating under a mistaken assumption.

23 BY MR. FLAHERTY:

24 Q. Do you understand Mr. Woodward's testimony
25 is that he bills United Cities based upon the winter

1 and summer plans?

2 A. As he said, he bills according to what
3 they forecast.

4 Q. And is it your understanding based upon
5 your reading of that contract that he has, that that's
6 what's stated in the contract, that he bills based
7 upon that summer and winter plan?

8 MR. BROEMEL: I'm going to object to
9 lack of foundation. If he could show him the
10 provision in the contract I think that would help
11 things.

12 MR. FLAHERTY: Well, he's reviewed
13 the contract. If he can answer without reviewing --
14 I'll be happy to pull the contract out and have him
15 review it.

16 THE WITNESS: Please.

17 MR. BROEMEL: All I know there's been
18 a representation that the contract has a certain term
19 that Counsel's defined. If he can show him the
20 contract.

21 CHAIRMAN GREER: He's going to pull
22 it.

23 MR. BROEMEL: He's what?

24 THE WITNESS: I have it.

25 MR. BROEMEL: Good, good, good.

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1 BY MR. FLAHERTY:
2 Q. Let me direct your attention to Exhibit A
3 of that purchase agreement.
4 A. Is that page 7 of 9?
5 Q. Page 7 of 9; correct.
6 A. Okay.
7 Q. And do you see in regards to the daily
8 purchased volumes a reference to a summer operational
9 and winter operational plan? It's paragraph 3.
10 A. I see it.
11 Q. And do you see on the next page, on page 8
12 of 9, a definition under service provisions of a
13 summer operational plan and a winter operational plan?
14 A. I don't. Because this -- I have a copy
15 filed March 16th, 1998. This was the page that was
16 missing, and that was brought up in the deposition.
17 So if I can have that, it would help.
18 Q. (Document passed to witness.)
19 A. Thank you.
20 Q. Do you see there's a reference to a summer
21 plan and a winter plan?
22 A. At page 8 of 9?
23 Q. Yes.
24 A. At what paragraph?
25 Q. It defines those two plans.

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1 A. Yes, I do. I see those.
 2 Q. And is it your testimony that upon
 3 reviewing that contract, you had no discussions with
 4 anyone at United Cities about how they developed their
 5 summer plan or winter plan?
 6 A. Not necessarily, not necessarily. Just a
 7 moment. Would you ask me one more time, please? Or
 8 would you read it back?
 9 Q. I'll just ask you the question again.
 10 DIRECTOR MALONE: Mr. Flaherty, can I
 11 ask you a question? You keep asking this witness if
 12 they got together with company person this or if they
 13 met with company person that. Are you implying that
 14 if the Advocate's office, if Dr. Brown had picked up
 15 the phone and called company person sub(b)(2)(4), that
 16 he would have had an opportunity to meet with them to
 17 go over whatever?
 18 MR. FLAHERTY: Absolutely. Anytime.
 19 Without a doubt.
 20 DIRECTOR MALONE: Well, that's -- you
 21 know, I don't remember -- the testimony of your
 22 witnesses will bear that out whether or not they
 23 testified to that or not.
 24 MR. WILLIAMS: The Consumer Advocate
 25 would also say the record will speak for itself how

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1 many times we appeared before this Agency trying to
 2 get information out of UCG.

3 MR. FLAHERTY: Do we have a pending
4 question?

5 THE WITNESS: Yes. You were going to
6 reask.

7 (Pause.)

8 COURT REPORTER: Do you need me to
9 read it?

10 MR. FLAHERTY: No, that's fine.

11 (Pause.)

12 CHAIRMAN GREER: It's your question.

13 DIRECTOR KYLE: I think it's a fair
14 line of questioning, but I just didn't get it resolved
15 which way you wanted to move.

16 DIRECTOR MALONE: Well, I think, you
17 know, the evidence in the record of the testimony of
18 UCG's witnesses will either bear that point out or
19 not. I don't remember them testifying to the specific
20 assertions that underlie Mr. Flaherty's questions.
21 But the transcript will bear that out.

22 DIRECTOR KYLE: So that was a
23 comment. You don't mind if he keeps pursuing that
24 line of questioning? Okay. I'm fine. I'm clear now.

25 THE WITNESS: I believe you were

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1 going to reask me a question. That's why I'm waiting.

2 MR. FLAHERTY: I thought I did reask
3 it. Let me reask it then.

4 BY MR. FLAHERTY:
5 Q. Did you have any discussions with
6 Mr. McDowell or his staff as to the summer plan or the
7 winter plan?
8 A. No, I did not, and neither did they call
9 me.
10 Q. Do you know how the summer or winter plan
11 relate to or how it interplays with the Woodward
12 contract?
13 A. Not very well at all, no.
14 Q. Did you send any discovery or data
15 requests asking how the winter or summer plan
16 interrelate with the Woodward contract?
17 A. I don't recall.
18 Q. If Mr. McDowell tells Mr. Woodward under
19 that contract that he wants, for example, 60,000 MCF
20 on Columbia Gulf, do you know why Mr. McDowell would
21 ask him for that specific requirement?
22 A. No, I don't.
23 Q. Do you know if it's tied back to his
24 transportation capacity contracts that he has with the
25 interstate pipelines?

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1 A. Yes. I would say it's tied back to any or
2 all in some fashion; the specifics, I don't know.
3 Q. In regards to the gas storage that
4 Mr. McDowell has, do you understand that in the winter
5 and summer plan that he provides to Mr. Woodward that

6 there's reference to gas storage?

7 A. I see it here, yes, storage; he does refer
8 to it, in winter and in summer.

9 Q. And do you know if the reason why
10 Mr. McDowell asked for certain requirements on gas
11 storage relates back to his contractual relationships
12 that he has with the interstate pipelines on storage
13 capacity?

14 A. Are you asking me if I know why?

15 Q. Yes. If that's the reason why he asks in
16 his plan for the gas to come out of storage?

17 A. I'm sorry. I don't understand your
18 question in the sense -- you're calling on me to
19 connect some things and I'm not sure what you're
20 asking me to connect. If you could repeat it in a
21 different way I'll certainly try my best to answer.

22 Q. If the winter plan contains an instruction
23 to Mr. Woodward that they want so much gas to come out
24 of storage, do you know if the reason why United
25 Cities asks that is tied back to its storage contract

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1 with the interstate pipeline?

2 THE WITNESS: Could the court
3 reporter repeat that to me now, please, slowly?

4 (The question beginning on
5 page 816, line 22, was read by the court reporter.)

6 THE WITNESS: No. And the reason I

7 don't know or fully comprehend your question is
8 because I don't know that Woodward is taking gas out
9 of storage. I didn't know that Woodward would take
10 gas out of storage.

11 BY MR. FLAHERTY:

12 Q. Do you understand that Woodward is an
13 aggregator of gas?

14 A. I don't know what you mean by
15 "aggregator," sir.

16 MR. FLAHERTY: That's all the
17 questions I have. Thank you.

18

19 EXAMINATION

20 BY DIRECTOR KYLE:

21 Q. Maybe you can educate me a little,
22 Dr. Brown. Let me just start with the premise -- the
23 first point on your summary, will you go back over
24 that with me?

25 A. Sure.

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1 Q. I feel a frustration here that maybe you
2 didn't get to elaborate or get out all your
3 explanation to the line of questioning. And I just
4 want to be fair. Most specifically -- maybe I should
5 break and give you a chance to answer it. But what
6 I'm getting to, Dr. Brown, remember when Counsel was
7 just asking you about Woodward's winter and summer
8 plan? And I thought we were talking about what you

9 would need in gas supply for winter and summer and how
10 that relates to prices. Would you go back over your
11 first point of your summary?

12 A. In my very first point in my summary was
13 that it appeared to me that the Woodward Marketing
14 contract results in United Cities purchasing higher
15 cost gas than otherwise would be the case. And I say
16 that because by looking at United Cities' purchases in
17 the first 12 months of the plan versus their purchases
18 in the second 12 months of the plan, there was a shift
19 from Tennessee Gas Pipeline as a major source of
20 supply to Columbia Gulf Gas Pipeline as a major source
21 of supply. And Columbia Gulf Pipeline appears to
22 have more expensive gas than Tennessee.

23 So, the step that falls after that, it's
24 my opinion, because this shift happened, this plan
25 allows for a shift from lower cost resources to higher

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1 cost resources even though --

2 Q. That's where I fouled up, Dr. Brown. You
3 just help me through. Why wouldn't it be from higher
4 to lower? I mean, you're saying it's lower to higher?

5 A. That is exactly what their data shows,
6 that the source of their gas supply shifted greatly
7 from Tennessee Gas Pipeline to Columbia Gas Pipeline.
8 And Columbia Gulf Gas Pipeline appears to be a higher
9 cost pipeline.

10 Now, my next statement was that this can
 11 happen because, according to this PBR plan, eight
 12 cents below the index is more expensive on a higher
 13 cost pipeline than eight cents below the index on a
 14 lower cost pipeline.
 15 Q. So it wouldn't capture the shift, as you
 16 were trying to explain?
 17 A. Exactly. So you could buy gas at eight
 18 cents below the index on a higher cost pipeline, and
 19 even though you're paying eight cents below the index,
 20 you're still paying more than what you were when you
 21 were purchasing gas on your lower cost pipeline. That
 22 is the loophole in this plan.
 23 Q. I'm clear with what you're trying to tell
 24 me now and I appreciate your patience.
 25 A. Sure.

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1 DIRECTOR KYLE: Thank you for letting
 2 me interrupt.
 3
 4 EXAMINATION
 5 BY DIRECTOR MALONE:
 6 Q. Dr. Brown, assuming that's true, of what
 7 benefit would there be to either United Cities Gas or
 8 Woodward?
 9 A. Well, the way the plan is set up, if you
 10 move to a higher-cost source and --
 11 Q. When you say "plan," are you talking

12 about --

13 A. The PBR plan, yes.

14 Q. -- if you move to a higher-cost source --
 15 there are two related things. Potentially, the volume
 16 of your savings is greater. For example, it's easier
 17 to find eight cents below the index when the index
 18 price is \$4 than it is to find eight cents below the
 19 index when the index is \$2. Therefore, when you have
 20 most of your purchases going on in the wintertime when
 21 prices are high, the odds are you're going to beat
 22 that index more often than in the summertime. For
 23 example, eight cents is a higher proportion of two
 24 bucks than it is of four bucks. And the higher gas
 25 prices go, the smaller is that eight cents.

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1 So getting back to that, if you have lots
 2 of volume predicated on eight cents and your index is
 3 four bucks, that's potentially a lot of money. And
 4 it's my intuition -- I guess it's my educated
 5 suspicion or guess, that most of the savings in this
 6 particular program would be being made in the winter
 7 months when prices are high and volumes are great.

8 Secondly, with regard to this shift -- and
 9 I have expressed my doubts about this -- if, in fact,
 10 you move to a higher-cost source, and, as Mr. Woodward
 11 indicated, you could buy gas in Tennessee yet sell it
 12 on Columbia, and bill it as if it came off of

13 Columbia. That's a nice margin. And that means that
14 in some fashion, you can have a potential to earmark
15 lower-priced gas for someone else.

16 For example, my testimony, I point to a
17 contract with Williams Pipeline. And that pipeline is
18 based on seven cents below FERC, nothing else. And we
19 know -- I think we generally have agreement here that
20 FERC is below the average of FERC, NGI, and NYMEX. So
21 seven cents below FERC is most likely cheaper than
22 eight cents below the indices of the other three --
23 excuse me -- the average of the other three indices.

24 Next point is that even though the
25 Williams Pipeline, quote, is a different pipeline that

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1 Columbia, Tennessee, East Tennessee, Texas Gas, and
2 Southern Natural, Mr. Woodward's deposition indicates
3 that you can buy gas on one pipeline and flow it to
4 another. And that the receiving point, or the person
5 who receives that gas, does not know the source.
6 Therefore, indeed, if the Williams contract is priced
7 below the United Cities contract, to me it seems quite
8 possible that low cost gas in Tennessee would filter
9 its way out of the fields and into the Williams
10 Pipeline. So I think those are two potential
11 advantages of moving from a lower-cost source to a
12 higher-cost source and yet being below that eight
13 cents below the index.

14 DIRECTOR KYLE: I appreciate that.
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15 Mr. Flaherty, I know I opened that up, so if you care
16 to come back and pursue it, that's perfectly all right
17 with the Agency.

18

19 RECROSS-EXAMINATION

20 BY MR. FLAHERTY:

21 Q. Do you know what fields the Williams
22 Pipeline takes gas from?

23 A. No, I don't.

24 Q. Do you know what pipelines gas that's
25 transported through Williams -- how many different

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1 pipelines the gas would have to go through to get to
2 Tennessee if it could?

3 A. I don't know. However, I would respond on
4 two different points. One, supposedly one of the big
5 advantages to FERC Order 636 was turning this market
6 into a more competitive one. And the interstate gas
7 pipelines are interconnected, supposedly; it's an
8 interconnected operation.

9 And the point of the interconnection was
10 to release -- or, excuse me -- was to no longer make
11 fields prisoner or captive holders to pipelines.
12 Those particular fields supposedly could reach out to
13 almost anyone in the country, and that was the point.

14 So I don't buy into the premise of your
15 argument that a field has to be connected to a certain

16 pipeline in order for that gas to get out.

17 For example, I don't agree with the
18 argument that unless Williams Pipeline is connected to
19 Field A and Great Falls, Montana, is on the Williams
20 Pipeline, that if you want to get -- excuse me. I'm
21 getting far afield here. I'll try it again.

22 The way things used to be in the gas
23 business, you had a gas field, you had a pipeline, and
24 then you had a buyer, and it went from field to
25 pipeline to buyer. And nobody -- if you weren't on

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1 this pipeline, you couldn't get through this field.
2 And the field, right here, they could only get to this
3 person out here, and it was the pipeline in between
4 that was controlling everything.

5 The idea behind FERC 636 was to break that
6 up so this field back here would have access to all
7 buyers, and these buyers out here would have access to
8 all fields. That was the whole idea behind making the
9 gas business competitive.

10 Q. It's not your testimony, though, that
11 someone could actually get gas that's on Williams
12 Pipeline economically to a customer in Tennessee? You
13 just don't know?

14 A. Well, not necessarily. Because gas is
15 often shifted through displacement. You put it in
16 down here at the Gulf, somebody else up in Boston can
17 take credit for that. Displacement is a common

18 practice.

19 Q. Do you know the difference between the
20 reservation charge on Columbia Gulf and the
21 reservation charge on Tennessee Pipeline?

22 A. According to -- yes. According to the
23 Exhibit RWM-R1 supplied by Mr. McDowell in his
24 original rebuttal testimony, the difference between
25 the charges is approximately \$10.39. And that was in

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1 January 1997.

2 Q. So would you agree that although it may be
3 cheaper -- you may have a cheaper source of supply on
4 Tennessee Pipeline than on Columbia Gulf, that if the
5 cost of transporting that commodity is more expensive
6 than on the pipeline that has the cheaper gas, that
7 the overall price to the city gate may be cheaper even
8 though it's on the more expensive pipeline?

9 A. I think that is a possibility, yes.
10 However, that kind of procedure implies that I can
11 shift one month -- well, one month I can shift
12 X-amount of gas down Tennessee, but they've had a
13 change in their demand prices, so the next month I'm
14 going to shift my transport. For example, the shift
15 in purchases from Tennessee to Columbia that the data
16 show, suggests that if Mr. McDowell's original exhibit
17 that he later withdrew was correct, and that you were
18 saving money in this year because you shifted

19 pipelines, it also implies that last year you were
20 losing money because you didn't.

21 Q. And all that would relate to whether or
22 not you had a contractual agreement that restricted
23 your ability to shift. Would you agree with that?

24 A. It's possible, yes.

25 Q. And you didn't ask Mr. McDowell or did not

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1 obtain contracts relating to his pipeline capacity or
2 whether or not those contracts expired so he could
3 shift; is that correct?

4 A. I don't believe we asked and I don't
5 believe he volunteered.

6 MR. FLAHERTY: That's all I have.
7 Thank you.

8 CHAIRMAN GREER: Mr. Broemel.

9
10 REDIRECT EXAMINATION

11 BY MR. BROEMEL:

12 Q. Early in the cross-examination you were
13 asked about assignment of contracts. Do you recall
14 that line of questions?

15 A. Yes.

16 Q. Have you heard any witness in this case
17 base an opinion on whether or not all contracts were
18 transferred?

19 A. No, I haven't.

20 Q. Do you understand the point or the

21 significance of the transfer of contracts you've been
22 asked about?

23 A. No, I don't know what Mr. Flaherty is
24 driving at.

25 Q. Now, I want to ask you about this revised

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1 exhibit that we've been talking about, the McDowell
2 exhibit. And I believe we already have in the record
3 the exhibit upon which it was based.

4 MR. BROEMEL: So let me give that to
5 the witness.

6 BY MR. BROEMEL:

7 Q. What I want to ask you is, do you
8 understand that this document that I've just given you
9 is a revision of RWM, Mr. McDowell's original exhibit?

10 A. Well, I understand that they call it a
11 revision. I don't agree with that.

12 MR. BROEMEL: Do the Directors have
13 the original exhibits still up there so he can put
14 these side by side and look at them? Okay.

15 BY MR. BROEMEL:

16 Q. Now, the first exhibit has how many
17 months?

18 A. The first exhibit shows one month,
19 January 1997.

20 Q. And how many months are on the next
21 exhibit, the so-called "revised exhibit"?

22 A. Well, on the left-hand side they show 12
23 months that they name from November '96 through
24 October 1997.

25 Q. Now, in these months that are listed, it

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1 goes November through October, is there any data for
2 April through October?

3 A. No. The schedule looks at if it's
4 incomplete.

5 Q. So can you draw any conclusions from this
6 exhibit?

7 A. Well, I can draw a conclusion based upon a
8 comparison of the two which I refer to in my
9 supplemental testimony.

10 Mr. McDowell apparently has retreated from
11 his first claim that in January of 1997 they save
12 \$538,000 by shifting from Tennessee to Columbia. I
13 can't -- and in his so-called "revision," first of
14 all, there's no capacity figures shown. For example,
15 in his first exhibit, RWM-R1, the third line from the
16 bottom, there's a line that says capacity on CGT. And
17 at the far right-hand side there's a number called
18 80,000.

19 Well, there are no capacity figures shown
20 in his revised exhibit. And in the revised exhibit,
21 everything appears there as a dollar figure, either
22 payout or revenue and, to me, that's a change.

23 Also I would point out that in the first
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24 exhibit that Mr. McDowell submitted that he's
25 hypothesizing a load factor of 200 percent in that

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1 month on Tennessee Gas Pipeline. That, too, is
2 mistaken because it can't be.

3 And in my supplemental testimony it was my
4 assertion that after I looked at these two, in my
5 supplemental testimony I assert that this is an
6 indication that the company doesn't really understand
7 what the contract does or how it operates because they
8 cannot determine what the savings were. They went
9 from \$500,000 in one month to \$400,000 throughout a
10 whole year.

11 Q. Yes. I want to ask you about that. This
12 RWM-R1, rebuttal 1, at the very last line it says net
13 savings on CGT versus TGP and it says 538,112.53. Do
14 you see that?

15 A. Yes, I do.

16 Q. Looking at this, is it your understanding
17 that this means that there was savings in one month of
18 \$538,000? Is that what this withdrawn exhibit is
19 purporting to state?

20 A. Yes, that was the claim.

21 Q. And now on the next exhibit, the so-called
22 "revised exhibit," what is the savings for the months
23 of November through October? And that means November,
24 December, January -- purportedly on the face of the

UCG33198
25 exhibit -- is it \$428,346?

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1 A. At the bottom of the exhibit, far
2 right-hand side, it says \$428,000. However, if you go
3 to January, you'll see that net savings is zip, zero.
4 This is quite a contrast with the original exhibit
5 that was filed. And, again, to me, it's an indication
6 of a lack of understanding of what's going on.

7 Q. And for the record, the revised exhibit
8 was filed when? This hearing began on, what,
9 March 25th? When was the revised exhibit filed?

10 A. Well, I believe it was filed 4:30,
11 March 25th, the day after we asked Mr. Woodward about
12 the original Exhibit RWM-R1 that had been filed
13 March 16th.

14 Q. And the hearing began on the 26th;
15 correct?

16 A. That day, yes.

17 Q. And do you believe more information would
18 be needed before anyone could draw any meaningful
19 conclusions from this revised exhibit?

20 A. Yes, definitely.

21 MR. BROEMEL: And I would like to
22 make that revised exhibit -- just so we'll understand
23 in conjunction with his testimony -- the next numbered
24 exhibit. I realize it's in the record, but it would
25 be convenient if it came in at this point.

1 CHAIRMAN GREER: That would be
2 Exhibit No. 24, without objection.

3 (Exhibit 24 marked.)

4 BY MR. BROEMEL:

5 Q. Now, you've been asked a number of
6 questions, a series of questions whether you ever
7 called Mr. McDowell and asked him to meet or had any
8 questions. Do you recall that?

9 A. Yes.

10 Q. Now, what is your understanding of the
11 rules in a contested case about contacting employees
12 of an adversary party?

13 A. You do it through data requests.

14 Q. If someone contacted you directly from an
15 adversary party, would you contact your attorney and
16 ask him about whether you should talk or could talk or
17 what the ground rules would be?

18 A. Yes, absolutely.

19 Q. At any time, did anyone at United Cities
20 Gas give you a blank invitation to call anyone you
21 wanted and chat about any matter?

22 A. No.

23 Q. Okay. Now, I believe you referred to this
24 issue of pipeline imbalances. Do you recall that?

25 A. I refer to that in my supplemental

1 testimony, yes.

2 Q. Right. And, in fact, Mr. Woodward at
3 first testified that there were certain pipeline
4 imbalances and then he later withdrew that; correct?

5 A. Yes, he did.

6 Q. And was his testimony in response to
7 testimony that you had made?

8 A. Yes. His original testimony in his
9 rebuttal regarding imbalances was a response to my
10 finding that United Cities had purchased more gas on
11 the Columbia Pipeline than, in fact, Woodward itself
12 had to sell.

13 Q. Now, did you use documents obtained as a
14 result of our motion to compel in discovery to come to
15 your conclusions about pipeline imbalances? Or at
16 least -- yes, I'll leave it at that.

17 A. I don't understand your question. Could
18 you ask me again, please?

19 Q. How did you come to conclude that -- let
20 me strike that last question.

21 At one point you had testified that it
22 appeared that they were, what -- I always get this
23 wrong -- selling more than they were buying?

24 A. Yes.

25 Q. Now, how did you come to conclude that?

1 A. All right. Through the data requests that
 2 we received, we were told that month by month Woodward
 3 purchased so much gas from Tennessee, so much gas from
 4 Columbia, so much gas from Texas Eastern, so much
 5 gas from Texas Gas Pipeline. And so we had
 6 month-by-month-by-month information on that, Woodward
 7 sources. And then we had month-by-month sources for
 8 what United Cities purchased from Woodward by
 9 pipeline.

10 So I compared what United Cities had
 11 purchased from Woodward by pipeline versus what
 12 Woodward had purchased on the same pipelines for the
 13 same months. And that's when we discovered that in
 14 some months for some pipelines Woodward sold more gas
 15 to United Cities than, in fact, Woodward had to
 16 supply.

17 Q. Okay. Now, Chairman Greer asked you a
 18 question about whether -- or has asked Mr. McCormac
 19 and maybe you too -- whether the documents you used as
 20 a result of the motion to compel were useful. Would
 21 you respond to that.

22 A. Extremely useful. None of the
 23 inconsistencies that have shown up in the past few
 24 days would have ever come out if we hadn't gotten that
 25 information.

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1 Q. So it's your testimony that this
2 information was useful to demonstrate inconsistencies?

3 A. Inconsistencies and this loophole in the
4 PBR that you could move to a higher cost pipeline and
5 still be buying gas eight cents below the index.

6 Q. So would it be fair to say that even
7 though the documents didn't complete the complex
8 picture that we're talking about, it did have a value
9 in alerting you to areas of inquiry?

10 A. Oh, absolutely. No question.

11 Q. Now, did the failure to get all the
12 information you requested under the data requests have
13 any impact on your investigations?

14 A. It made it very difficult to understand
15 what was going on. I think we got a clear picture in
16 time and through the depositions. I'd say that it was
17 hard, made it harder.

18 MR. BROEMEL: Let me just check. I
19 think that may be my last question.

20 (Counsel conferring.)

21 MR. BROEMEL: I have one question
22 based on the contract. And for the convenience of
23 everyone, I'm just going to hand this out. We don't
24 need to make it an exhibit, but this is Exhibit A that
25 we talked about.

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1 BY MR. BROEMEL:

2 Q. And I want to refer to -- I'll give you an
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3 unmarked copy. I'm just going to refer briefly to
4 Item 2 here. And this is just for your convenience to
5 follow along. We don't need to make it an exhibit. I
6 believe you were asked a series of questions about the
7 seasonal winter and summer operational plan. Do you
8 recall that?

9 A. Yes.

10 Q. And why you didn't infer that the price to
11 be charged was that of the pipeline on which the gas,
12 I guess you would say, was delivered. Do you recall
13 that, rather than the actual cost?

14 A. I recall.

15 Q. Would you look at paragraph 2 of this
16 document called "purchase price NBTU."

17 A. Yes.

18 Q. And let me just read this: The basket of
19 indices used to determine benchmark pricing for
20 monthly base low spot purchases describing United
21 Cities Gas purchase incentive mechanism currently in
22 effect in the state of Tennessee minus eight cents
23 plus other past due charges described below under
24 service provisions. If the incentive mechanism is
25 changed to the detriment of either party, the parties

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1 agree to negotiate the purchase price.

2 Is there anything in this paragraph that
3 discusses the price that is paid that refers to this

4 operational plan, summer or winter operational plan?

5 A. No.

6 MR. BROEMEL: I have no further
7 questions.

8 CHAIRMAN GREER: We need to take a
9 five-minute break at least. Can we finish up with
10 Mr. Novak in about 30 minutes?

11 MR. WILLIAMS: Less than that
12 probably.

13 CHAIRMAN GREER: Any other questions
14 for Dr. Brown? If not, then we'll dismiss Dr. Brown.
15 I'm also going to dismiss Mr. McCormac. I don't think
16 Mr. Williams is going to dismiss you, but we'll
17 dismiss you.

18 (Recess taken from 4:55 to
19 5:05 a.m.)

20 CHAIRMAN GREER: I assume your next
21 witness is Mr. Novak. Let me remind you you're still
22 under oath.

23 ///

24 ///

25 ///

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1 HAL NOVAK,
2 was called as a witness, and having been previously
3 sworn, was examined and testified as follows:

4

5 DIRECT EXAMINATION
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**BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:

**PETITION OF CHATTANOOGA GAS
COMPANY FOR APPROVAL OF
ADJUSTMENT OF ITS RATES AND
CHARGES, COMPREHENSIVE RATE
DESIGN PROPOSAL, AND REVISED
TARIFF**

DOCKET NO. 06-00175

CONSUMER ADVOCATE'S PHASE 2 ISSUES LIST

Robert E. Cooper, Jr., the Attorney General and Reporter for the State of Tennessee, through the Consumer Advocate and Protection Division of the Office of Attorney General ("Consumer Advocate"), respectfully submits this issues list for phase 2 of this case. Attached as an exhibit to this issues list is the affidavit of Dr. Stephen N. Brown and the attachments to the affidavit.

Proposed Conservation and Usage Adjustment

1. Should Chattanooga Gas Company's conservation and usage adjustment be accepted, rejected, modified or replaced?
2. If the conservation and usage adjustment is modified or replaced, how should it be modified or with what should it be replaced?
3. If the conservation and usage adjustment is allowed in any form, should Chattanooga Gas Company be required to reduce its excess pipeline capacity to correspond with the impact of conservation in reducing pipeline capacity needs?

Proposed Energy Conservation Program

4. Should Chattanooga Gas Company's energy conservation program be accepted, rejected, modified or replaced?
5. If the energy and conservation program is modified or replaced, how should it be modified or with what should it be replaced?
6. If the energy conservation program is allowed in any form, should Chattanooga Gas Company be required to reduce its excess pipeline capacity to correspond with the impact of conservation in reducing pipeline capacity needs?

Capacity Release and Related Issues

7. How is Chattanooga Gas Company compensated for the sale, lease, or release of capacity and any other gas supply assets, and is that compensation fair to consumers?
 - A. What is the bidding process, and is it fair?
 - B. What asset management arrangements or contracts are or have been in place with regard to capacity and any other gas supply assets, and are they fair to consumers?
 - C. How are FERC-mandated payments handled, and is the handling fair to consumers?
8. What exactly is the amount of total capacity and other gas supply assets, and what amount of capacity or gas supply assets are available for the sale, lease, or release to third parties or affiliates or divisions of Chattanooga Gas Company?
 - A. What is the appropriate level and mix of capacity and other gas supply assets?
 - B. What has been the record of capacity and other asset planning in the past?
 - C. What are the future plans for capacity and other gas supply assets?
 - D. Has Chattanooga Gas Company oversubscribed to storage and capacity assets to handle

its jurisdictional requirements?

E. Has Chattanooga Gas Company utilized the appropriate mix of firm transportation, peaking capacity, and storage capacity?

F. Is Chattanooga Gas Company delivering its supply to storage at the appropriate times of the year and at the appropriate cost?

G. What safeguards exist or should exist to guarantee that the customers of Chattanooga Gas are being treated fairly regarding the sales and purchases of natural gas?

9. What is the appropriate relation between Chattanooga Gas Company and Sequent and any other affiliated entity or division related to AGL Holding Company?

A. What process is utilized to ensure that Sequent pays the fair market value for rights to utilize or market the assets paid for by the customers of Chattanooga Gas Company?

B. Should Chattanooga Gas Company be subject to requirements for affiliate transactions similar to those required for Atmos Energy Corporation?

10. Are consumers receiving fair compensation for the assets related to the sale, lease or release of idle gas supply assets and excess capacity for which they have paid?

A. How much money has Sequent paid to Chattanooga Gas Company in recent years for rights to utilize or market assets paid for by the customers of Chattanooga Gas Company?

B. How much money has Sequent made from the assets paid for by the customers of Chattanooga Gas Company in recent years?

C. What safeguards exist or should exist to guarantee that the customers of Chattanooga Gas Company are being treated fairly with regard to excess capacity and storage assets?

11. Should the Tennessee Regulatory Authority impute to Chattanooga Gas Company all or a

portion of the profits Sequent generates through its management of Chattanooga Gas Company's idle gas supply assets and excess capacity?

12. Should Chattanooga Gas Company return to consumers or share with consumers the money it receives from Sequent under the terms of the asset management contract?

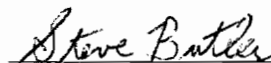
Need for Contested Case on Capacity Release and Related Issues

The need for a contested case on capacity release and related issues already has been briefed in TRA docket number 05-00258. The specific facts regarding the specific entities at issue are important, and discovery will be needed to learn the facts of the case. In a rulemaking proceeding without discovery, neither the TRA nor the Consumer Advocate would learn the facts necessary to understand what Chattanooga Gas Company and its affiliate asset manager Sequent are doing with the excess capacity and gas storage assets paid for by consumers. In a rulemaking proceeding without discovery, neither the TRA nor the Consumer Advocate would learn the facts necessary to understand how much money Sequent has been and is making at the expense of the customers of Chattanooga Gas Company. In a rulemaking proceeding without discovery, neither the TRA nor the Consumer Advocate would learn the facts necessary to understand whether consumers are being treated fairly by Chattanooga Gas Company with respect to the excess capacity and gas storage assets paid for by consumers. A contested case on these issues would be an opportunity for the TRA to learn the facts related to issues of serious importance to the customers of Chattanooga Gas Company.

As discussed in the Recommendation of the Hearing Office Regarding the Dismissal of Phase Two and the Need for a Rulemaking to Resolve Asset Management Issues, filed on October 6, 2006, by Director Ron Jones, acting as Hearing Officer, TRA docket number 05-00258, the standards for convening a rulemaking established in *Tennessee Cable Television Association v. Tennessee Public*

Service Commission, 844 S.W.2d 151, 162 (Tenn. App. 1992), are not met on these issues. The Affidavit of Stephen N. Brown, attached as an Exhibit to this Consumer Advocate's Phase 2 Issues List, establishes that there are significant facts specific to Chattanooga Gas Company and its affiliate asset manager Sequent that justify a contested case and that weigh against a rulemaking proceeding. Discovery will be needed to learn what is not necessarily available in the public domain. Given that consumers are required to pay for all of Chattanooga Gas Company's pipeline capacity, even for pipeline capacity that is not used to transport natural gas for their use, the TRA should utilize this opportunity to learn the facts regarding Chattanooga Gas Company's pipeline capacity and related issues.

RESPECTFULLY SUBMITTED,



STEPHEN R. BUTLER, B.P.R. #14772

Assistant Attorney General

Office of the Attorney General

Consumer Advocate and Protection Division

P.O. Box 20207

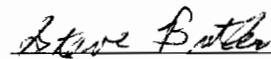
Nashville, Tennessee 37202

(615) 741-8722

FAX: (615) 532-2910

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on the parties of record via U.S. Mail on February 9, 2007.



Stephen R. Butler

#103981

**IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:	) DOCKET NO. 06-00175
	)
PETITION OF CHATTANOOGA	)
GAS COMPANY FOR APPROVAL	)
OF ADJUSTMENT OF ITS RATES	)
AND CHARGES,	)
COMPREHENSIVE RATE DESIGN	
PROPOSAL, AND REVISED TARIFF	

AFFIDAVIT OF STEPHEN N. BROWN

I, Stephen N. Brown, being duly sworn, depose and say:

1. I am an economist in the Consumer Advocate and Protection Division, Office of the Attorney General and have held this position since 1995. In that capacity, I review utility filings and information relating to rates and rate changes and follow the economic conditions that affect the companies. Also, I assess and evaluate facts for the Consumer Advocate and Protection Division and other entities within the Office of the Attorney General.

2. From 1986 to 1995 I was employed by the Iowa Utilities Board as Chief of the Bureau of Energy Efficiency, Auditing and Research, and Utility Specialist and State Liaison Officer to the U.S. Nuclear Regulatory Commission. From 1984 to 1986, I worked for Houston Lighting & Power as Supervisor of Rate Design. From 1982 to 1984, I worked for Arizona Electric Power Cooperative as a Rate Analyst. From 1979 to 1982, I worked for Tri-State Generation and Transmission Association as Power Requirements Supervisor and Rate Specialist. My work spanned many issues including cost of service studies, rate design issues,

telecommunications issues and matters related to the disposal of nuclear waste.

3. I have an M.S. in Regulatory Economics from the University of Wyoming, an M.S. and Ph.D. from the University of Denver, and a B. A. from Colorado State University.

4. I am providing this affidavit in regard to Phase 2 of the instant proceeding.

5. In particular, I am giving my opinion that there is good reason and ample evidence in this case to proceed with Phase 2 in the manner proposed by the CAPD. My opinion is based not only on my direct testimony, pages 50-58, which I have already provided in this docket and which establishes that Chattanooga Gas Company's contracts are managed in concert with Sequent. My opinion is also based on the exhibits I have attached to this affidavit.

6. The exhibits consist of:

A) The United States Security and Exchange Commission's order of September 28, 2005 captioned "Release No. 35-28038; 70-10304 AGL Resources Inc. Order Authorizing the Acquisition of Nonutility Businesses and Participation in the System Money Pool," said in its Order that "Sequent, LLC ("Sequent"), [is] an indirect, wholly-owned subsidiary company of AGL, is engaged in the optimization of natural gas assets, gas transportation and storage, producer and peaking services and the wholesale marketing of natural gas. Sequent's asset optimization business focuses on capturing value from idle or underutilized natural gas assets..." This helps to show that pipeline capacity that is not used by consumers creates profit potential for Sequent, which is an affiliate of Chattanooga Gas Company. It is important to note that the Chattanooga's idle or underutilized pipeline capacity at issue is paid for entirely by consumers.

B) The Prepared Rebuttal Testimony Of Eileen E. Goldsack dated May 31, 2002 and given on behalf of Atlanta Gas Light in Federal Energy Regulatory Commission Docket No. RP01-245-000, where Ms. Goldsack testified at page 6 that “Sequent Energy Marketing, L.P. manages Atlanta’s gas assets pursuant to an agreement entered into by Atlanta and Sequent’s predecessor in 1996.” This helps to demonstrate that there has been a long-standing relationship between Sequent and the companies that control the pipeline capacity. It also helps to show that Sequent has a long-standing goal of turning the idle capacity that it manages into profit.

C) The Direct Testimony Of James C. Yardley, President of Southern Natural Gas Company, in Federal Energy Regulatory Commission Docket No. RP99-496 and dated August 31, 1999, where Mr. Yardley testified at pages 9 and 10: “Southern expects intense competitive pressure as marketers strive to reduce their costs by retaining or causing Atlanta to retain no more FT than is absolutely necessary...A number of marketers... have stated that Atlanta has too much firm transportation capacity under contract.” This helps to show that Chattanooga Gas Company, as an affiliate of Atlanta Gas Light Company, also might have too much firm transportation, especially considering the admitted impact of conservation on natural gas use. It should be noted that Chattanooga Gas Company was a subsidiary of Atlanta Gas Light Company before the AGL Holding Company was formed in 2000.

D) The Request For Rehearing of The Alabama Municipal Distributors Group et. al in Federal Energy Regulatory Commission Docket No. CP02-1-002 and dated October 17, 2002 where the petitioners argued at page 13 that “The risk of capacity turnback was for Southern a

driving force underlying the settlement approved in Docket No. RP99-496. All of Southern's customers were provided a significant rate reduction below current rates in exchange for a commitment to extend their contracts until October 31, 2005. In addition, Atlanta Gas Light Company ("Atlanta"), historically the largest customer on the system, was provided with several sizeable discounts that dwarfed any other discount provided by the settlement. See e.g. March 10, 2000 Offer of Settlement, Article V, Section 7 of the Stipulation and Agreement in Docket No. RP99-496.” This tends to show that Atlanta, an affiliate of Chattanooga Gas Company that also utilizes Sequent to manage its capacity assets, chose to keep large amounts of capacity when given the choice. Sequent turns the idle capacity into profits.

E) The Direct Testimony Of Glenn A. Sheffield, Director of Rates for Southern Natural Gas Company, in Federal Energy Regulatory Commission Docket No. RP04-523 and dated August 20, 2004 where Mr. Sheffield testified at pages 38 and 39 that: “...Southern [is] at significant risk of turnback...approximately 31% of Southern’s firm transportation contracts, measured by contract demand, will come up for renewal before the end of 2005.” This tends to show a continuing thread from the testimony of James C. Yardley from (C) above that Southern Natural Gas Company was concerned recently about the potential problem of oversubscription to pipeline capacity and the possibility of significant turnback of the capacity for firm transportation.

F) The Initial Post-Technical Conference Comments of Atlanta Gas Light Company and Chattanooga Gas Company in Federal Energy Regulatory Commission Docket No. RP04-523 and dated January 7, 2005 where at pages 3 and 4 the companies state their opposition to changes

in Southern's General Terms and Conditions Southern's regarding "PSC-Out" language in Southern's tariff, a copy of which appears in my direct testimony, page 56. This shows that Chattanooga Gas Company wanted to preserve its ability to drop contracts for pipeline capacity within 90 days if a state regulatory authority ordered it to reduce its firm transportation assets. Chattanooga Gas Company did not want to be locked into a 24-month notice requirement as proposed by the pipeline. This helps to show that Chattanooga Gas Company has at least considered the possibility that a state commission, such as the Tennessee Regulatory Authority, could conclude that Chattanooga Gas Company is subscribing to too much firm transportation capacity.

G) Southern's Offer of Settlement in Federal Energy Regulatory Commission Docket No. RP04-523 and dated April 29, 2005 where at page 12 Southern offers the parties the opportunity to extend contracts through August 31, 2010. This is the same 5-year approach as referenced above in (D). This helps to show that Chattanooga Gas Company and all other customers of Southern had an opportunity to extend their firm transportation contracts.

H) The Initial Comments of Atlanta Gas Light Company and Chattanooga Gas Company In Support Of Offer Of Settlement in Federal Energy Regulatory Commission Docket No. RP04-523 and dated May 19, 2005 where at page 1 the companies state their support of Southern's Offer. This tends to show that Chattanooga Gas Company has the same interests as Atlanta Gas Light Company in extending the firm transportation contracts. Both company's assets are managed by Sequent, which makes profits from idle assets.

I) Southern's Offer of Settlement in Federal Energy Regulatory Commission Docket No. RP04-523, and dated April 29, 2005 where at page 13 Southern writes that "Appendix D hereto lists shippers that have elected in writing not to extend all or a portion of one or more of their firm contracts." This shows that some companies chose not to extend their contracts for firm transportation.

J) Appendix D of Southern's Offer lists Tennessee Municipalities and Utility Districts that, unlike Chattanooga Gas, chose not to extend firm transportation contracts. The amount of daily firm transportation capacity which the municipalities chose to discontinue is also listed:

Jefferson-Cocke County Utility District	350
Knoxville Utilities Board	10,000
Middle Tennessee Natural Gas Utility District	1,000
Oak Ridge Utility District	100
Powell Clinch Utility District	500

This shows that Chattanooga Gas Company did not decline to extend its contracts for firm transportation, unlike other local gas service providers in Tennessee.

K) Transcript of Federal Energy Regulatory Commission Dockets Nos. PL04-17 and AD04-11 "IN THE MATTER OF: STATE OF THE NATURAL GAS INDUSTRY CONFERENCE, STAFF REPORT ON NATURAL GAS STORAGE," dated October 21, 2004 -- at pages 141-147, where at page 142 the representative of the American Gas Association explains his Power Point presentation and states that "The planning focus of any LDC is to

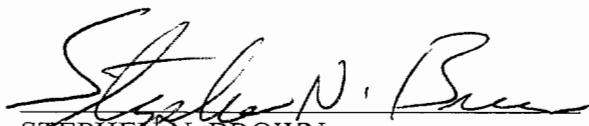
optimize its capacity portfolio to meet that load duration curve. We want to do two things. We want to maintain reliable service and we want to meet it at least cost...An optimized portfolio...can be broken into three parts...firm transportation...Storage...[and] peak shaving ... They also are part of close scrutiny by state commissions.” This helps to show that it is generally accepted that cost minimization should be part of a local distribution company’s supply planning. It also shows that close scrutiny by state commissions is anticipated.

L) The American Gas Association’s Power Point Presentation as just described, consisting of 17 pages where CAPD’s annotations appear near the bottom of the chart on the left side of page 6. This helps to show that proper least-cost planning includes peak shaving and storage withdrawals. The chart on page 6 also makes clear that when energy conservation or other factors cause the load duration curve to shift downward, there is more idle capacity available for capacity release from firm transportation.

7. The behavior of Chattanooga Gas towards extending firm transportation contracts is clearly different from the behavior of some municipalities and utility districts in Tennessee. To the extent that Chattanooga Gas extends the life of firm transportation contracts while actively participating in the capacity release markets through Sequent’s efforts, and where such contract extensions occur without presenting a needs-assessment to the Tennessee Regulatory Authority and receiving the considered approval of the Authority, consumers served by regulated utilities in Tennessee may not have the opportunity to enjoy the benefits that flow to customers served by unregulated utilities, when in the considered judgment of the municipality or the

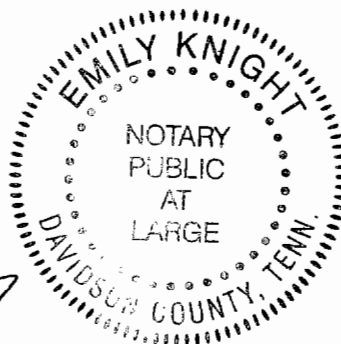
district, the public interest is served by either not renewing contracts for firm transportation or by reducing the amount of firm transportation. Phase 2 is clearly needed in this docket and it should proceed along the lines suggested CAPD. The Phase 2 issues proposed by the CAPD provide this Authority an opportunity to review issues of great importance to Tennessee consumers.

I swear and affirm that the statements in this affidavit are true and correct.


STEPHEN N. BROWN
Economist
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202
(615) 741-3132

Sworn and subscribed before
me this 2nd day of February, 2007


NOTARY PUBLIC

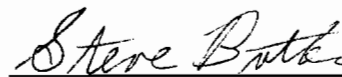


My commission expires: Sept. 22, 2007

My Commission Expires SEPT. 22, 2007

CERTIFICATE OF SERVICE

The undersigned hereby certifies that true and exact copies of the forgoing documents were delivered via U.S. Mail to the parties of record in this action on the 9th day of February, 2007.


Stephen R. Butler

EXHIBIT

A

SECURITIES AND EXCHANGE COMMISSION

(Release No. 35-28038; 70-10304)

AGL Resources Inc.

Order Authorizing the Acquisition of Nonutility Businesses and Participation in the System Money Pool

September 28, 2005

AGL Resources Inc. ("AGL"), Atlanta, Georgia, a registered holding company has filed an application-declaration ("Application") with the Securities and Exchange Commission ("Commission") under sections 6(a), 7, 9(a), 10, 11(b) and 12(b) of the Public Utility Holding Company Act of 1935, as amended ("Act") and rule 54 under the Act. On July 27, 2005, the Commission issued notice of the Application (Holding Co. Act Release No. 28004).

AGL requests authority to organize and finance one or more direct or indirect subsidiaries to engage in certain gas- and energy-related nonutility businesses in Canada, Mexico and/or the United States.

I. Background

AGL distributes natural gas to more than 2.2 million end-use customers through public-utility company subsidiaries organized in Georgia (Atlanta Gas Light Company), Tennessee (Chattanooga Gas Company), Virginia (Virginia Natural Gas Inc. and Virginia Gas Distribution Company) and New Jersey (Pivotal Utility Holdings, Inc.). Pivotal Utility Holdings owns and operates utility facilities in New Jersey, Florida and Maryland through the following divisions: Elizabethtown Gas, Florida City Gas, and Elkton Gas.

AGL is also involved in various energy- and gas-related nonutility businesses, including: retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for its own utilities as well as for other non-affiliated companies;

operation of high deliverability underground natural gas storage; and construction and operation of telecommunications conduit and fiber infrastructure within select metropolitan areas. The common stock of AGL is listed on the New York Stock Exchange.

Through various subsidiaries, Sequent, LLC ("Sequent"), an indirect, wholly-owned subsidiary company of AGL, is engaged in the optimization of natural gas assets, gas transportation and storage, producer and peaking services and the wholesale marketing of natural gas. Sequent's asset optimization business focuses on capturing value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in, or contractual rights to, natural gas transportation and storage facilities. Margins are typically created in this business by participating in transactions that balance the needs of varying markets and time horizons. Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the Eastern and Mid-Continental United States. Sequent also purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to the other alternatives available to its end-use customers.

II. Requests For Authority

AGL requests authority to acquire interests in energy- and gas-related nonutility businesses operating in Canada, Mexico and/or the U.S ("Foreign Nonutility Businesses").¹ Typically, these investments will be made through one or more direct or indirect subsidiaries of Sequent and funded by acquisitions of equity and debt securities of Foreign Nonutility

¹ Rule 58 does not permit the acquisition of these businesses because "substantially all" of their revenues will not be derived from activities within the United States.

Businesses, borrowings from AGL's nonutility money pool by Foreign Nonutility Businesses, and guarantees.² AGL will limit its direct and indirect investments in Foreign Nonutility Businesses to an aggregate amount not to exceed \$300 million ("Investment Limit") in the form of equity, debt and guarantees, including nonutility money pool borrowings, through February 8, 2006 ("Authorization Period").³

The specific nonutility businesses in which AGL seeks authorization to invest include:

(1) energy management services and other energy conservation related businesses;⁴ (2) the maintenance and monitoring of utility equipment; (3) the provision of utility related or derived

² The proposed investments would be subject to the limits set forth in Holding Co. Act Release No. 27828, (April 1, 2004). In addition, AGL's public-utility company subsidiaries will not directly or indirectly acquire any Foreign Nonutility Businesses, and they will not provide funding for, extend credit to, or guarantee the obligations of Foreign Nonutility Businesses.

³ AGL's investments in "gas-related companies" and "energy-related companies" within the meaning of rule 58 are subject to the investment limits under that rule, not to the Investment Limit.

⁴ Energy management services include: the marketing, sale, installation, operation and maintenance of various products and services related to energy management and demand-side management, including energy and efficiency audits; meter data management, facility design and process control and enhancements; construction, installation, testing, sales and maintenance of (and training client personnel to operate) energy conservation equipment; design implementation, monitoring and evaluation of energy conservation programs; development and review of architectural, structural and engineering drawings for energy efficiency, design and specification of energy consuming equipment and general advice on programs; the design, construction, installation, testing, sales, operation and maintenance of new and retrofit heating, ventilating, and air conditioning, gas, electrical and power systems, alarm, security, access control and warning systems, motors, pumps, lighting, water, water-purification and plumbing systems, building automation and temperature controls, installation and maintenance of refrigeration systems, building infrastructure wiring supporting voice, video, data and controls networks, environmental monitoring and control, ventilation system calibration and maintenance, piping and fire protection systems, and design, sale, engineering, installation, operation and maintenance of emergency or distributed power generation systems, and related structures, in connection with energy-related needs; and the provision of services and products designed to prevent, control, or mitigate adverse effects of power disturbances on a customer's electrical systems.

software and services; (4) engineering, consulting and technical services, operations and maintenance services; (5) brokering and marketing of natural gas, electricity and other energy commodities and providing incidental related services, such as fuel management, storage and procurement; and (6) oil and gas exploration, development, production, gathering, transportation, storage, processing and marketing activities, and related or incidental activities. AGL is not seeking authority to acquire any assets that would cause any subsidiary to be or become an "electric-utility company" or "gas-utility company," as those terms are defined in sections 2(a)(3) and 2(a)(4) of the Act, respectively. AGL will report its investments in its Canadian and Mexican gas- and energy-related companies in a supplement to its regular quarterly reports filed on Form U-9C-3.

In addition, AGL requests authority for all Foreign Nonutility Businesses to participate as borrowers and lenders in the nonutility money pool authorized by Commission order dated April 1, 2004 (Holding Co. Act Release No. 27828). Participation in the nonutility money pool will include unsecured short-term borrowing, contributing surplus funds, and lending and extending credit to other nonutility money pool participants.

The proposed transaction is subject to rule 54, which provides that, in determining whether to approve certain transactions other than those involving exempt wholesale generators ("EWGs") or foreign utility companies ("FUCOs"), as defined in the Act, the Commission will not consider the effect of the capitalization or earnings of any subsidiary which is an EWG or FUCO if the requirements of rule 53(a), (b) and (c) under the Act are satisfied. AGL states that neither it nor any of its subsidiaries presently has an interest in any EWG or FUCO. Therefore, the requirements of rule 53 are satisfied.

III. Conclusion

AGL estimates that the fees, commission and expenses incurred in connection with the proposed transaction will be approximately \$12,000. The company states that no state or federal commission, other than this Commission, has jurisdiction over the proposed transactions.

Due notice of the filing of the Application has been given in the manner prescribed, and no hearing has been requested of or ordered by the Commission. Upon the basis of the facts in the record, it is found that the applicable standards of the Act and rules are satisfied, and that no adverse findings are necessary.

IT IS ORDERED, that the Application, as amended, is granted and permitted to become effective immediately, subject to the terms and conditions contained in rule 24 under the Act.

For the Commission by the Division of Investment Management, pursuant to delegated authority.

Jonathan G. Katz
Secretary

EXHIBIT

B

LEBOEUF, LAMB, GREENE & MACRAE
L.L.P.

A LIMITED LIABILITY PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS

1875 CONNECTICUT AVENUE, N.W.
WASHINGTON, DC 20009-5728

(202) 986-8000

TELEX: 440274 FACSIMILE: (202) 986-8102

WRITER'S DIRECT DIAL
(202) 986-8013

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The Hon. David I. Harfeld
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Transcontinental Gas Pipe Line Corp.,
Docket No. RP01-245-000

Dear Judge Harfeld:

Enclosed for filing with the Commission is the prepared rebuttal testimony of Eileen E. Goldsack on behalf of Atlanta Gas Light Company in the above referenced proceeding.

The undersigned certifies that the foregoing prepared written testimony is being served upon all the parties listed on the Commission's service list for this proceeding. Should you have any questions regarding this filing, please contact the undersigned at (202) 986-8013.

Yours truly,

Elias G. Farrah (Signature)

Elias G. Farrah
Attorney for Atlanta Gas Light
Company

Enclosures

cc: Magalie R. Salas, Secretary FERC
Erin M. Murphy, Law Clerk for Judge Harfeld
All parties

FEDERAL ENERGY REGULATORY COMMISSION
Docket No. RP01-245-000....
Hearing Ex. No. 1-1-1.....
Date Identified 7-15-02.....
Date Admitted 7-15-02.....

Exhibit No. AGL-1

1 UNITED STATES OF AMERICA
2 BEFORE THE
3 FEDERAL ENERGY REGULATORY COMMISSION
4

5 Transcontinental Gas Pipe Line Corporation) Docket No. RP01-245-000
6

7 PREPARED REBUTTAL TESTIMONY OF EILEEN E. GOLDSACK
8 ON BEHALF OF
9 ATLANTA GAS LIGHT COMPANY
10

11 Q. Please state your name and address?

12 A. Eileen E. Goldsack, 1219 Caroline Street N.E., Atlanta, Georgia.

13 Q. Please state your employer and present position.

14 A. I am employed by AGL Resources, Inc., the holding company of parties to this
15 proceeding; Atlanta Gas Light Company ("AGLC" or "Atlanta") and Virginia Natural Gas, Inc.
16 ("VNG"), as Legal and Policy Advisor.

17 Q. Have you provided copies of your background and professional experience?

18 A. Yes. Attachment A contains a summary of my background and experience.

19 Q. What is the purpose of your rebuttal testimony?

20 A. My testimony is being filed on behalf of Atlanta and responds to a portion of the prepared
21 direct testimony of Mr. Michael P. Wingo, which was filed on behalf of South Carolina Pipeline
22 Corporation and SCANA Energy Marketing, Inc., (collectively ("SEMI"). Specifically, my
23 testimony refutes Mr. Wingo's proposal that the Commission mandate the conversion of services
24 currently provided to Atlanta by Transco under Part 157 of the Commission's regulations to Part
25 284 service over Atlanta's objection.

26 Q. Please summarize your conclusions.

27 A. Mr. Wingo's proposal should be rejected because: (i) Atlanta is not seeking to convert its
28 Part 157 services to Part 284. Mr. Wingo's proposal is squarely at odds with longstanding and

Exhibit No. AGL-1
Docket No. RP01-245-000
Page 2 of 7

1 well established Commission Policy against forcing any customer to convert from Part 157 to
2 Part 284 service; (ii) SEMI's ultimate goal of forcing Atlanta to release its capacity on Transco
3 to them is also directly at odds with longstanding Commission policy against forcing a customer
4 to release its capacity to third parties; (iii) the extraordinary relief requested by SEMI is
5 unnecessary since Atlanta has provided them with the use of this capacity to serve customers in
6 Georgia in a manner that is substantially similar to the manner in which they could utilize this
7 capacity if they obtained the release of this capacity which they desire; and (iv) their allegations
8 with respect to Atlanta's marketing affiliate are not only irrelevant, they are false and misleading.

9 **Q. Which Atlanta-Transco service agreements is SEMI seeking to have converted from**
10 **Part 157 to Part 284 service?**

11 **A.** SEMI stated on Page 2, Lines 20-23 of Mr. Wingo's prepared testimony that it is seeking
12 conversion of the Part 157 services provided by Transco to Atlanta under Transco's Rate
13 Schedules GSS, LG-A, LSS and SS-1.

14 **Q. Is Atlanta seeking to convert these service agreements from Part 157 to Part 284**
15 **service?**

16 **A.** No.

17 **Q. Has the Commission addressed the conversion of Part 157 to Part 284 service over a**
18 **shipper's objection?**

19 **A.** Yes. It is my understanding that the Commission's policy in this regard is well settled.
20 The Commission has held that even the pipeline service provider cannot convert Part 157
21 services to Part 284 service without the shipper's consent or over the shipper's objection. Simply
22 put, the Commission has not compelled a shipper to convert to Part 284 service. In *Northern*

1 *Border Pipeline Company*, 81 FERC ¶ 61,402 (1997)(*"Northern Border"*) the Commission held
2 that:

3 Order No. 636 allows for the voluntary abandonment of Part 157 service
4 to Part 284 service, *although a pipeline cannot mandate a shipper to*
5 *convert its Part 157 service to service under Part 284.* No shipper other
6 than Panhandle has filed in opposition to Northern Border's proposal.
7 Thus, in this case, with the sole exception of the transportation service for
8 which Panhandle is guarantor . . . , the Commission believes that Northern
9 Border's proposal to abandon firm service to PAGUS in order to convert it
10 to Part 284 service is permitted by the public convenience and necessity.

11
12 However, the same cannot be said regarding the volumes . . . for which
13 Panhandle remains guarantor in the event of a PAGUS default. Because
14 of Panhandle's guarantor obligation, it stands as the ultimate shipper for its
15 original portion of the . . . capacity. *As discussed above, the Commission*
16 *will not compel section 7(c) shippers to convert to service under Part 284.*
17 Therefore, we will not force Panhandle to submit to the conversion of the
18 . . . section 7(c) firm transportation service. Northern Border's request to
19 abandon that portion of PAGUS' section 7(c) capacity is denied.

20
21 81 FERC at 62,844 (emphasis added).

22
23 **Q. Has the Commission also addressed attempts by third parties to force a customer to**
24 **convert to Part 284 Service?**

25 **A. Yes.** It is my understanding that the Commission has been equally clear that a third party
26 cannot force a conversion to Part 284 if the shippers do not consent to conversion. Applying
27 Commission policy, the judge in *Great Lakes Gas Transmission Limited Partnership*, 70 FERC ¶
28 63,001 (1995)(Leibman, J.), *aff'd*, 74 FERC ¶ 61,257 (1996), ruled:

29 In urging the presiding judge to require Great Lakes to allocate costs to the
30 [affected] services based on zoned Mcf miles, TransCanada argues that all
31 of the attributes of Part 284 service would be available to ANR and NMU
32 if they were to convert the T rate schedules to Part 284 service. *The short*
33 *answer to this argument is that ANR and NMU have chosen not to convert*
34 *and do not want to be forced to convert. . . . While the Commission has*
35 *encouraged customers to convert from Part 157 service to Part 284*
36 *service, it has not required such conversions, and it has maintained the*
37 *differences between these classes of service.*

1
2 70 FERC at 65,013 (emphasis added). The Commission expressly affirmed the judge on this
3 point. 74 FERC at 61,856-57. Thus, there is no question that SEMI cannot seek to compel the
4 conversion of Atlanta's Part 157 services when it is clear that Atlanta does not consent to such
5 conversion.

6 **Q. Has the Commission addressed the issue of whether a Shipper can be forced to**
7 **release capacity once service has been converted to Part 284 service?**

8 **A.** Yes. It is my understanding that Commission policy is equally clear that Atlanta cannot
9 be forced to release its capacity against its will even if the service was converted to Part 284
10 service. For example, in *Southern California Edison Company v. Southern California Gas*
11 *Company*, 79 FERC ¶ 61,157, *reh'g denied*, 80 FERC ¶ 61,390 (1997), the Commission denied a
12 complaint that would have required the release of capacity against the wishes of the capacity
13 holder, Southern California Gas Company ("SoCal Gas"). The Commission stated:

14 While the Commission is concerned about the potential for the exercise of
15 market power in the secondary market and issues relating to the most
16 efficient use of existing capacity, *our regulations do not require firm*
17 *holders of capacity to release their capacity.* If the firm holder decides to
18 release its capacity, however, it is required to do so on a nondiscriminatory
19 basis. We do not find that SoCal Gas has withheld capacity on an unduly
20 discriminatory basis. Since the Commission finds no violation of its
21 regulations, the Commission is dismissing Edison's complaint.

22
23
24 79 FERC at 61,662 (citation omitted).

25
26 **Q. Does Atlanta make any of the service it receives from Transco available to**
27 **Marketers in Georgia to serve retail customers in Georgia?**

28 **A.** Yes. SEMI's request for extraordinary Commission relief is unnecessary in that Atlanta
29 has made its capacity on Transco (provided under Transco Rate Schedules LG-A, LSS,

1 and SS-1) available to Marketers under a state program that allow Marketers like SEMI
2 to utilize this capacity in a manner substantially similar to the way in which they could
3 utilize this capacity if it were released to them on a limited Part 284 basis (just capacity
4 release and the same receipt and delivery points) and they held the capacity on Transco in
5 their own name.

6 **Q. Please describe in more detail Atlanta's state program that makes Transco capacity**
7 **available to Marketers.**

8 **A.** Under Atlanta's Georgia Public Service Commission ("GPSC") authorized Parking and
9 Redelivery Service ("PRS") Rate Schedule, Atlanta utilizes its Transco and Cove Point
10 LNG, Inc. ("Cove Point") to: 1) receive gas delivered by the Marketer to Atlanta's
11 citygate; 2) park the gas; and 3) redeliver the gas upon nomination by the Marketer.
12 Atlanta aggregates services it receives from Transco and Cove Point under Rate
13 Schedules LSS, SS-1, LG-A and Rate Schedules FPS-1 and FTS-1 in order to provide
14 PRS to the Marketers in Georgia. Under Rate Schedule PRS, marketers are able to park
15 or redeliver gas based on specified parking and redelivery periods. The parking period is
16 from April 1st through October 31st. The redelivery period is from November 1st through
17 March 31st. These specified periods are based on the physical limitations of the storage
18 services that make up the PRS Rate Schedule. Based upon the parking and redelivery
19 periods, marketers are able to nominate daily on all four-nomination cycles for parking or
20 redelivery service at their discretion to serve either their firm or interruptible market.
21 Additionally, each Marketer owns and manages the inventory in PRS and is allotted its
22 own PRS capacity, parking rights and redelivery rights based on each Marketer's market
23 share of firm demand on Atlanta's system.

1 Q. Do you agree with Mr. Wingo's claim (at page 8) that the PRS service is analogous
2 with the Commissions generic finding in "Order No. 636 where.... pipelines bundled
3 sales structure to be unjust and unreasonable and sought to give pipeline customers
4 direct control over the transportation components of their traditional sales
5 service...?"

6 A. No, as previously described, Atlanta's PRS is not a bundled sales service as Mr. Wingo
7 may lead you to believe. Quite the contrary, marketers purchase gas and therefore are in
8 control of their gas cost. Marketers also have the discretion to determine the quantity of
9 gas they park into PRS to serve their firm market needs.

10 Q. How is the Transco GSS service that Atlanta has under contract utilized under the
11 state program?

12 A. In 1998, in Docket No. 8390-U, the GPSC authorized AGLC to retain a certain level of
13 interstate pipeline assets for system balancing. As a result, the GSS service was retained by
14 AGLC. Atlanta utilizes its retained storage to provide marketers with a no-notice service to
15 balance on a daily basis the Marketers' firm customer loads. The retained storage is also used to
16 balance shippers accounts daily for interruptible demand behind AGLC's system. The GPSC
17 reaffirmed the level of retained storage in September 2001 in Docket No. 14060-U.

18 Q. Do you agree with Mr. Wingo's assertion that the GPSC found that Atlanta's
19 affiliate utilized this capacity in a manner contrary to that of the Georgia retail customers?

20 A. No. Atlanta's affiliate, Sequent Energy Marketing, L.P. ("Sequent"), manages Atlanta's
21 gas assets pursuant to an agreement entered into by Atlanta and Sequent's predecessor in 1996.
22 The terms of that agreement and the agreement itself were approved by the GPSC. Recently,
23 Atlanta sought to replace that agreement with a new "Bailment Agreement." In Atlanta's most

Exhibit No. AGL-1
Docket No. RP01-245-000
Page 7 of 7

1 recent Capacity Supply Plan, the GPSC found that the terms of this new agreement had not
2 received the necessary review and approval. The GPSC merely found that the bailment
3 agreement with Sequent could potentially give rise to a conflict of interest. The GPSC did not
4 find that Atlanta in fact acted in its own self-interest nor did the GPSC preclude subsequent
5 approval of the agreement.

6 **Q. Do you have an opinion concerning Mr. Wingo's assertion that if Atlanta's capacity**
7 **were released, Marketers could trade among themselves and optimize the use of storage**
8 **capacity?**

9 **A. Yes.**

10 **Q. What is that opinion?**

11 **A.** Pursuant to Rate Schedule PRS, Marketers are free to transfer inventory amongst
12 themselves or sell the inventory to other parties on any given day. The inventory in PRS is
13 owned and managed by each individual Marketer and allows them the opportunity to optimize
14 the use of storage inventory and take advantage of arbitrage opportunities when they arise.

15 **Q. Does this conclude your testimony?**

16 **A. Yes.**

Attachment A

EILEEN E. GOLDSACK

Educational Background and Professional Experience

Educational Background

Ms. Goldsack graduated from Mercer University in 1979 with a Bachelors of Science Degree in Mathematics. Mr. Goldsack also graduated second in her class from Atlanta Law School while working full time with Atlanta Gas Light Company ("AGLC").

Professional Experience

In 1980 Ms. Goldsack began her career with AGLC as a Utility Analyst in the rate department. Ms. Goldsack's responsibilities included the preparation of rate design analysis for use in the company's rate case applications before the Georgia Public Service Commission ("GPSC"). In 1986 she assumed the position of Senior Rate Analyst, where she acted as project leader in the planning, scheduling and preparation of rate design and cost of service analyses for use in AGLC's rate case applications before the GPSC.

In 1988, Ms Goldsack became Director, Federal Regulatory Affairs responsible for the corporate planning, review, and administration of all federal regulatory matters as they affect AGLC and other subsidiaries of AGL Resources, Inc. (the "Company"). She represents the Company in proceedings before the Federal Energy Regulatory Commission ("FERC") and when necessary advocates positions at FERC as a witness in hearings before FERC Administrative Law Judges. Ms. Goldsack also coordinates corporate communications and acts as a liaison with numerous Company departments with respect to federal regulatory issues. In January 2001, she moved to the Legal Department where she also assumed responsibility for the oversight of state regulatory matters. In September 2001, she became Legal and Policy Advisor responsible the formulation and implementation of policy and legal positions on major federal and state regulatory initiatives that directly impact the Company's future business opportunities.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

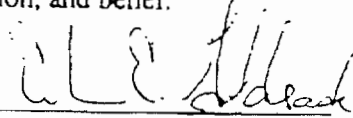
Transcontinental Gas Pipe Line Corporation

Docket No. RP01-245-000

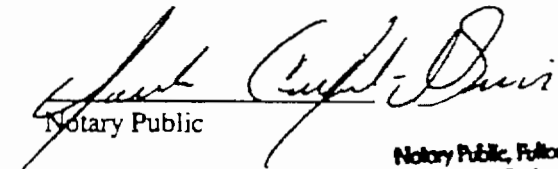
State of Georgia)
)
County of) SS:

AFFIDAVIT of EILEEN E. GOLDSACK

I, Eileen E. Goldsack, being duly sworn, depose and state that the contents of the foregoing Prepared Rebuttal Testimony of Eileen E. Goldsack are true, correct, accurate and complete to the best of my knowledge, information, and belief.


Eileen E. Goldsack

Subscribed and sworn to before me this 29th day of May, 2002.


Notary Public

My Commission expires: Notary Public, Fulton County, Georgia
My Commission Expires September 20, 2005

EXHIBIT

C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Natural Gas Company) Docket No. RP99-___-000

PREPARED DIRECT TESTIMONY
OF
JAMES C. YARDLEY
ON BEHALF OF
SOUTHERN NATURAL GAS COMPANY

1 Q. Please state your name, position, and business address.

2

3 A. My name is James C. Yardley. I am President of Southern Natural Gas Company
4 ("Southern"). My business address is the AmSouth-Sonat Tower, 1900 5th Avenue
5 North, Birmingham, Alabama 35203.

6

7 Q. Please briefly state your education and professional background.

8

9 A. I graduated from Duke University in 1973 with an undergraduate degree in Economics. I
10 subsequently received an MBA from Harvard Business School in 1978. I was employed
11 by Southern beginning in 1978 in the Corporate Planning Department. I subsequently
12 held various management and senior management positions in the Planning, Marketing,
13 Business Development, and Executive areas of Southern and other Sonat Inc. subsidiaries
14 prior to appointment to my present position in May 1998.

15

16 Q. What are your responsibilities as President of Southern?

17

1 A. I am responsible for the overall business and operations of Southern, including the
2 development and execution of Southern's strategies, the provision of reliable
3 transportation services to our customers, and the pursuit of new business opportunities.
4

5 Q. What is the purpose of your direct testimony in this case?
6

7 A. I will testify concerning the business risks faced by Southern that form a basis for
8 Southern's proposed rate of return on equity.
9

10 Q. How do you define business risk?
11

12 A. Business risk refers generally to the uncertainty associated with the business or
13 operations of a company. Business risk is all risk other than financial. It encompasses all
14 operating factors – productivity, competition, markets, and regulations – that bear on an
15 adequate return on equity for the firm.
16

17 Q. Please summarize your direct testimony.
18

19 A. In my view, Southern faces significant business uncertainty relating to the potential for
20 underrecovery of costs due primarily to the risks of (1) contract terminations, (2) the
21 significant level of contracts that come up for renewal by 2002, (3) the relatively short
22 average remaining term of its long-term contracts and the even shorter terms of its
23 contract renewals, and (4) the intense and increasing level of pipeline competition in its

1 major market areas. These risks have recently increased with the substantial LDC
2 unbundling on Southern's system. Because of these factors, Southern's business risks are
3 higher than the average pipeline.

4
5 Q. Would you briefly describe Southern's pipeline system?

6
7 A. Southern is a regional pipeline serving the Southeastern United States. This is an area
8 characterized by cold winters of relatively brief duration when compared to the longer
9 winters of the mid-Atlantic, northeastern, and mid-western gas markets. Southern has
10 firm capacity into its market areas of approximately 2.5 Bcf per day. Our major markets
11 are in the states of Alabama, Georgia, and South Carolina, which account for nearly 90%
12 of Southern's transportation and storage revenues.

13
14 Significantly, Southern's pipeline is configured in a distribution-like system as shown in
15 the map attached as Exhibit No. SNG- _____ (JCY-2) to this testimony. Our system is
16 designed to provide multiple delivery points to many of our customers. For example,
17 Southern provides deliveries to Atlanta Gas Light Company (AGLC), its largest
18 customer, at 56 delivery points throughout the state of Georgia. Similarly, we provide
19 delivery to Alabama Gas Corporation, our second largest customer, at 75 delivery points
20 located throughout the state of Alabama. Additionally, Southern provides deliveries to
21 the Municipal Gas Authority of Georgia and its member cities at 23 delivery points
22 throughout the state of Georgia. Many of Southern's other customers also receive service
23 at multiple delivery points.

1 Q. What are the competitive implications of Southern's geographic location and pipeline
2 configuration?

3
4 A. There are several. First, Southern's average system utilization is lower than its principal
5 competitors. While Southern's system terminates in Tennessee and South Carolina, its
6 competitors extend into the northeast where they serve areas of more sustained cold
7 weather.

8
9 Second, since our storage fields are located in the production area, we do not enjoy – as
10 some of our competitors do – the continued market area throughput to fill up market area
11 storage. Thus, while Southern's annual utilization rate has been increasing
12 (approximately 72% in 1998), it is below the load factor of our biggest competitor,
13 Transcontinental Gas Pipeline ("Transco"), which is a long-line northeast pipe that has an
14 annual utilization rate of more than 85% into its market area.

15
16 The third competitive implication of Southern's distribution-like configuration is that we
17 have higher per-unit fixed costs, when compared to long-line transmission systems,
18 related to the distribution-like nature of our system. In essence, rather than have our
19 customers build their distribution systems to our mainlines, we have invested substantial
20 capital to build our pipeline system to serve our customers at a myriad of delivery points
21 throughout a wide geographic area. While this configuration provides a valuable service
22 to our customers, it also entails substantial additional capital and operating and
23 maintenance costs when compared on a unit of throughput basis with major long-line

1 pipelines. Primarily as a result of these factors, Southern's principal pipeline competitor,
2 Transco, has significantly lower filed rates than Southern in its major market areas as set
3 forth below:

	<u>FT Reservation Charges</u> \$/Dth		
	<u>Alabama</u>	<u>Georgia</u>	<u>South Carolina</u>
Transco (from Transco Station 85/ Mobile Bay line)	\$5.18	\$5.18	\$7.79
Southern (current settlement rates)	\$8.62	\$11.37	\$11.37

4
5 Q. Has Transco evidenced a willingness to expand its pipeline into the Southeastern United
6 States?

7
8 A. In the five years since the end of Southern's last rate case, Transco has announced or
9 placed in service six pipeline expansions, with total firm capacity of over 600,000 mcf/d
10 into the Southeast and Mid-Atlantic states. These expansions included an additional
11 400,000 mcf/d of firm service into Alabama, Georgia, and South Carolina, Southern's
12 major market areas. Southern's shippers have often subscribed for Transco's competing
13 expansions. We expect this trend to continue as indicated in Transco's April 15, 1999
14 announcement of a proposed Sundance Expansion to serve markets in Alabama, Georgia,
15 and the Carolinas. What this means for Southern is continuing competitive pressures to
16 provide rate discounts to retain existing loads as well as increasing risk of loss of existing
17 loads to new expansion projects.

18

1 Q. Has competition with Transco intensified in recent years?

2

3 A. Yes, it has. By shifting some of its expansion costs to its firm shippers in the Mid-
4 Atlantic and Northeastern states, Transco has been able to aggressively expand its
5 pipeline to serve additional Southeast markets in the last several years. Transco's recent
6 SouthCoast Expansion Project, for example, which provides an additional 61,600 dth/d of
7 firm transportation service to AGLC, is priced on a rolled-in rate basis. Transco has
8 recently announced that it will seek rolled-in rates for its proposed Sundance expansion
9 into the Southeast.

10

11 By contrast, many of Transco's earlier system expansions were priced on an incremental
12 rate basis. For example, Transco's SunBelt Project, which was placed in service in 1997,
13 provided an additional 75,700 mcf/d of firm transportation service to South Carolina
14 Pipeline at a weighted average incremental reservation rate of approximately \$12.30/dth.
15 Transco has recently announced its intention to propose roll-in of the SunBelt Project in
16 Transco's next general rate case. See Answer of Transcontinental Gas Pipe Line
17 Corporation to Comments, Requests for Conditions and Protests filed June 24, 1999, in
18 *Transcontinental Gas Pipe Line Corp.*, Docket No. CP99-392-000, p. 9. The rolled-in
19 rate to South Carolina Pipeline, Southern's third largest customer, is likely to be in the
20 range of \$9.50 to \$10.00/dth.

21

22 Q. Are there other pipeline competitors in Southern's major markets?

23

1 A. Yes, there are. A number of Southern's pipeline competitors are shown on the map
2 attached as Exhibit No. SNG-_____ (JCY-3) to this testimony. East Tennessee Natural
3 Gas currently provides approximately 45,000 mcf/d to Chattanooga Gas Company in
4 Tennessee and 59,000 mcf/d to AGLC in northwest Georgia. In addition, Columbia Gulf
5 Transmission and MCN Energy Group Inc. announced in April 1999 an open season
6 offering of up to 250,000 dth/d of capacity in the Volunteer Pipeline, a proposed new
7 pipeline to extend from an interconnection with Midwestern Gas Transmission near
8 Portland, Tennessee to an interconnection with AGLC near Chattanooga, Tennessee to
9 serve markets in Georgia and the Southeast. Finally, in 1997, AGL Resources, Inc. and
10 Transco announced a joint venture for a new pipeline, called the Cumberland Pipeline, to
11 provide additional service from Transco's interstate pipeline into the northern Atlanta
12 metro region and northern Georgia. While this project ultimately did not go in service, it
13 is indicative of the continued high-level interest by existing and potential pipeline
14 competitors to provide additional gas service into the Southeast.

15

16 Other competitors include Florida Gas Transmission Company (FGT) and Koch Gateway
17 Pipeline Company (Koch), which currently provides pipeline service in southeast
18 Alabama. Significantly, FGT's western division reservation rate of \$2.44/dth extends
19 through southern Alabama to the Alabama-Florida state line, where FGT's market area
20 rate zone begins. Similarly, Koch's FT reservation rate in southeast Alabama is
21 \$5.84/dth. Both of these rates compare favorably with Southern's current settlement
22 Zone 2 FT reservation rate of \$8.62/dth. Other potential competitors include Duke
23 Energy, which has announced plans to build the Sawgrass Energy Transmission System

1 from southeastern Alabama, across Mobile Bay, and through the Florida panhandle into
2 peninsular Florida.

3
4 Q. Please describe Southern's transportation contracts.

5
6 A. Southern is currently fully subscribed in its major market areas (Zones 2 and 3). By the
7 end of 2002, approximately 42% of our existing firm contracts (measured by
8 transportation demands) will come up for renewal as shown in Exhibit No. SNG-____
9 (JCY-4). The weighted average remaining term of Southern's long-term firm
10 transportation contracts is only 4.8 years (as of March 1, 2000). Exhibit No. SNG-____
11 (JCY-5). This compares with an average remaining term for U.S. pipelines in excess of 8
12 years for all firm contracts, and in excess of 10 years for long-term firm contracts.
13 Energy Information Administration, *Natural Gas 1998: Issues and Trends*, pp. 132-133
14 (June 1999). With the level of competition from other pipelines, Southern will face
15 strong challenges to maintain its existing load. This is evidence of the high level of
16 business risk that Southern faces.

17
18 Q. What other factors affect the recontracting risk that Southern faces?

19
20 A. AGLC is Southern's largest customer, representing approximately 40% of Southern's
21 total revenues. By October 1999, AGLC will have completely unbundled its system and
22 exited the gas merchant function. This unbundling, which was initiated following the
23 passage of legislation in Georgia in 1997, has proceeded at a pace that has been

1 unprecedented in the industry. Indeed, AGLC will be the largest, fully unbundled LDC
2 in the nation by October.

3
4 Southern has contracts with AGLC for over 600,000 Mcf/d of firm transportation demand
5 which come up for renewal in August 2002. What AGLC's unbundling means for
6 Southern is that the future level of AGLC's transportation contracts and the term of those
7 contracts are very uncertain. As the American Gas Association recently observed in
8 assessing the impact of state unbundling on LDC contracting decisions:

9 Uncertainty about the future level of demand, who their customers will be,
10 and the potential treatment of stranded costs makes many LDCs reluctant
11 to contractually commit to [pipeline] capacity for any significant period of
12 time.

13
14 American Gas Association, *The Changing Nature of Pipeline Capacity Contracts and the*
15 *Potential for Future Capacity Turnback by Local Distribution Companies*, January 1998,
16 p.15.

17
18
19 Q. Does AGLC's unbundling have other effects on Southern?

20
21 A. Yes. Not only is the overall level of FT service likely to change, but also the type of
22 services which marketers utilize to provide gas service to the end-use customers. Thus,
23 Southern expects intense competitive pressures as marketers strive to reduce their costs
24 by retaining (or causing AGLC to retain) no more FT than is absolutely necessary, and
25 substituting other services, such as capacity release and IT, wherever possible. In
26 addition, Southern will face additional competition from the marketers themselves, who
27 can rebundle transportation and storage services on several pipelines with the gas
28 commodity to provide a delivered market area service, often with greater flexibility in

1 price and terms than the tariff-based services that an interstate pipeline must offer. A
2 number of these marketers, such as SCANA, have publicly stated their views that AGLC
3 has too much firm transportation capacity under contract and that AGLC should no
4 longer hold the level of pipeline firm transportation contracts that are currently
5 subscribed. See, Motion to Intervene and Protests of SCANA Energy Marketing, Inc., p.
6 5-9, filed May 27, 1999, in *Transcontinental Gas Pipe Line Co.*, Docket No. CP99-392.
7 This means even greater competitive and decontracting pressures for Southern which
8 further exacerbate Southern's business risks.

9
10 Q. But isn't the recontracting risk mitigated by the growing demand for gas in the
11 Southern's major markets?

12
13 A. Only to some extent. It is true that gas demand in the Southern's major markets
14 (Alabama, Georgia, and South Carolina) is growing at a rate faster than the national
15 average (an average annual rate of 3.1% over the last 10 years compared to 2.6%
16 nationally). Energy Information Administration, *Historical Natural Gas Annual 1930*
17 *through 1997*, pp. 230, 250. Southern has been fortunate to secure a portion of that
18 growth through market expansions. But due to intense pipeline competition as described
19 above, Southern faces a decreasing likelihood that it will be able to continue to capture a
20 meaningful portion of the market growth, or that it will be able to retain the existing level
21 of business on its pipeline.

22

1 As I have previously stated, approximately 42% of Southern's current long-term FT
2 contracts will expire by the end of 2002. The conditions in its markets make the renewal
3 of these contracts far from certain. And Southern's experience indicates that most
4 renewals will be for relatively short terms. Failure to renew or resubscribe even 10% of
5 the contracts that end by 2002 could mean an annual reservation revenue loss to Southern
6 of as much as \$17.5 million. These recontracting risks are particularly acute in light of
7 the structural, cost, and rate differences between Southern, a distribution-like system, and
8 Transco, a long-line pipeline with whom we compete.

9
10 Q. Does cost-of-service rate regulation mitigate the pipeline's financial risks of turnback?

11
12 A. No. In assessing the business risks that Southern faces, it should be noted that the FERC
13 has not insured full-cost recovery for interstate pipelines that have faced significant
14 capacity turnbacks from current customers. Rather, FERC's approach in the rate cases of
15 El Paso Natural Gas Company, Transwestern Pipeline Company, and Natural Gas
16 Pipeline Company of America has been to encourage pipelines to remarket turnback
17 capacity. Regardless of the merits of FERC's position, the agency has nonetheless made
18 it clear that pipelines should not expect full recovery of all costs of turnback capacity. As
19 a result, Natural, El Paso, and Transwestern entered into settlements in which the
20 pipelines assumed significant risks of remarketing the turnback capacity. So it is a risk
21 that we take very seriously at Southern.

22

1 Q. How does Southern's average remaining contract life compare with the depreciable life
2 of its pipeline system?

3

4 A. Under the FERC's approach to turnback capacity and its cost-of-service ratemaking,
5 Southern has no assurance that it will be able to fully recover the cost of its facilities.
6 This is because depreciation rates are generally not set based on the life of the contracts.

7

8 The weighted average life of Southern's firm transportation contracts is 4.8 years (as of
9 March 1, 2000). Yet, Southern's pipeline transmission facilities, which comprise the
10 bulk of its rate base, are depreciated over a 50 year period based on a 2% composite
11 annual depreciation rate that is applied to gross plant. As Ms. Hardy's testimony
12 indicates, Southern's net plant is approximately \$1.1 billion. At an annual depreciation
13 and amortization expense of approximately \$50 million, which Southern proposes in this
14 rate proceeding (see Exhibit No. SNG-_____ (TSH-2) p. 2), Southern's pipeline system
15 will have a depreciable life of approximately 22 years. The significant gap between
16 Southern's remaining average firm transportation contract life of only 4.8 years and its
17 remaining pipeline depreciable life of 22 years represents a very substantial business risk.
18 Looking forward, Southern's investors face approximately 17.2 years of depreciation
19 expense and fixed cost recovery not covered by contracted revenues.

20

21 Q. Is the risk of remarketing turnback capacity unique to Southern?

22

1 A. No, but I believe it is more significant for Southern than other pipelines in general for
2 several reasons. First, the average remaining term of Southern's long-term firm contracts
3 is only 4.8 years – less than half of the national average, as I've explained. Second,
4 AGLC's unbundling has progressed faster and farther than any other state LDC
5 unbundling in the country. AGLC will be completely unbundled and out of the merchant
6 function within the next two months. This will result in additional pressures by retail
7 marketers – who have clearly indicated their views that AGLC has "too much" pipeline
8 FT capacity – for AGLC to reduce the level of FT held and to seek lower cost
9 alternatives. Third, while Southern provides a valuable distribution-like service, its
10 system configuration also results in a higher per unit cost structure than its long-line
11 competitors who are able to cherry pick major loads in Southern's principal market areas.
12 Thus, while other pipelines may face capacity turnback risks, the recontracting risks for
13 Southern are greater than the risks faced by other pipelines in general.

14
15 Q. Does Southern have other business risks?

16
17 A. While the degree of recontracting risk and the level of pipeline competition are the
18 principal risks, Southern also faces a significant risk in recovering the approximately
19 \$11.8 million of fixed costs that have been allocated to Southern's interruptible
20 transportation service. As described in Mr. Outlaw's testimony, capacity release is very
21 competitive with Southern's interruptible transportation (IT) service, and it will present a
22 substantial challenge for Southern to achieve the levels of IT throughput that are

1 necessary to recover the \$11.8 million of fixed costs that are allocated to IT service in
2 this rate filing.

3
4 Q. What is your overall assessment of Southern's business risks?

5
6 A. Based on Southern's level of recontracting risk, the significant level of contracts that
7 come up for renewal by 2002, the relatively short average remaining term of Southern's
8 long-term firm contracts, and the relatively short terms of its contract renewals, the
9 intense and increasing pipeline competition in Southern's major markets, and the level of
10 cost recovery that is dependent upon IT service, I conclude that Southern's business is of
11 greater risk than the average pipeline.

12
13 Q. What measures has Southern taken to respond to the intense pipeline competition in its
14 market area?

15
16 A. We have implemented measures to become more productive and efficient in our business
17 and operations. Through these efforts, which included a substantial reengineering of our
18 business processes in 1996-97, we have been able to reduce the number of employees
19 needed to run the pipeline from 1,154 in 1993 to 758 as of April 30, 1999 – a reduction of
20 34%. We have reduced our combined Operations & Maintenance (O&M) and
21 Administrative & General (A&G) expenses from \$150 million in the 1995 RP93-15
22 settlement to \$144.5 million in this rate case, even though during that period we have
23 increased salaries to retain and motivate our workforce and have added pipeline

1 expansion facilities of more than \$270 million, including approximately 36,000
2 horsepower of additional compression, which otherwise increase O&M costs.

3
4 Q. Does the cost of service in this filing reflect any projected savings related to the proposed
5 merger of El Paso Energy Corporation and Sonat Inc.?

6
7 A. No, it does not. Nor does the filing reflect any costs related to the proposed merger or
8 any possible merger-related restructurings. While it is true that El Paso's management
9 has publicly stated that it expects to realize \$60 million of undefined cost savings, it must
10 be noted that such savings, if achieved, would occur within a very large organization – of
11 which Southern would represent only a relatively small part. The savings could involve
12 cost reductions within the combined entity's gas and electricity marketing groups, the
13 exploration and development company, the corporate services group, or El Paso's
14 pipelines other than Southern. One would also expect that there will be corresponding
15 restructuring and other charges related to the cost savings. Thus the timing, and the level,
16 of overall net savings, if any, to Southern, is speculative at this time.

17
18 Q. What else has Southern done to respond to competitive conditions?

19
20 A. In addition to our drive for improved efficiency and productivity, we have responded to
21 market conditions in several ways. First, we have strived to provide safe and reliable
22 service to our customers. These efforts have included the replacement of old 1940s-
23 vintage coupled pipe throughout Southern's system and the replacement of compressor

1 engines at Enterprise, Mississippi. It should be noted that in an independent national
2 survey conducted each year by the Southern Gas Association, Southern has been ranked
3 #1 in safety among all major pipelines for 8 of the last 10 years (Exhibit No. SNG-_____
4 (JCY-6).

5
6 Second, we have discounted our rates where necessary, in our judgment, to meet
7 competition and win or retain markets, as described in Ms. Parker's testimony.

8
9 Third, we have selected a rate of return on equity that is slightly below the median cost of
10 equity determined under the FERC's method, even though Southern faces greater than
11 average business risk compared to other pipelines.

12
13 Q. Why, given Southern's greater than average business risk, have you selected an equity
14 return that is below the median rate of return on equity established in Dr. Williamson's
15 analysis?

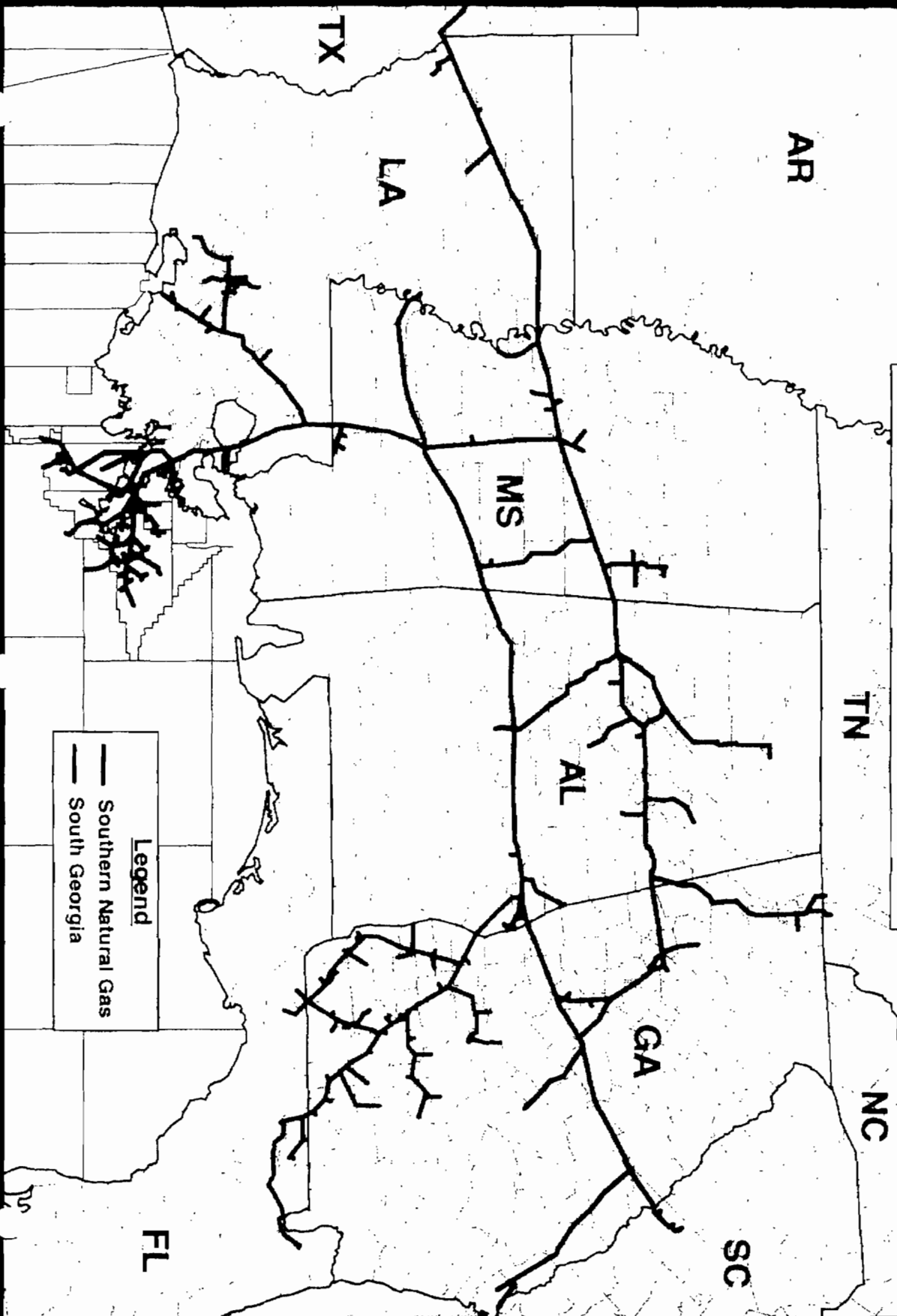
16
17 A. We selected the 13.0 percent return on equity based on our need to respond to the current
18 market and competitive conditions. The 13.0 percent return balances Southern's need for
19 an adequate rate of return with our need to recognize market conditions.

20
21 Q. Does this conclude your testimony?

22
23 A. Yes.

Southern Natural Gas General System Map

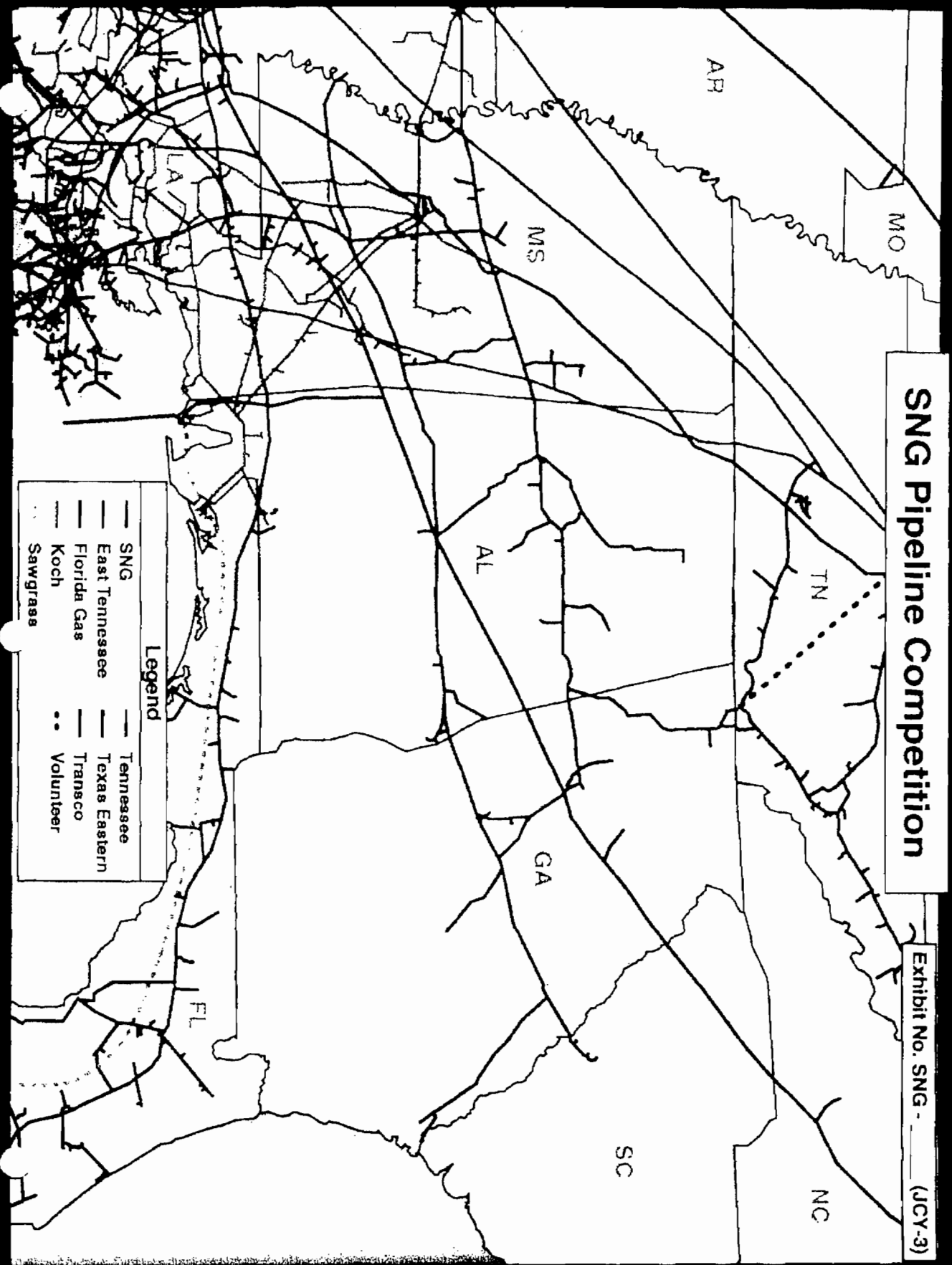
Exhibit No. SNG - _____ (JCY-2)



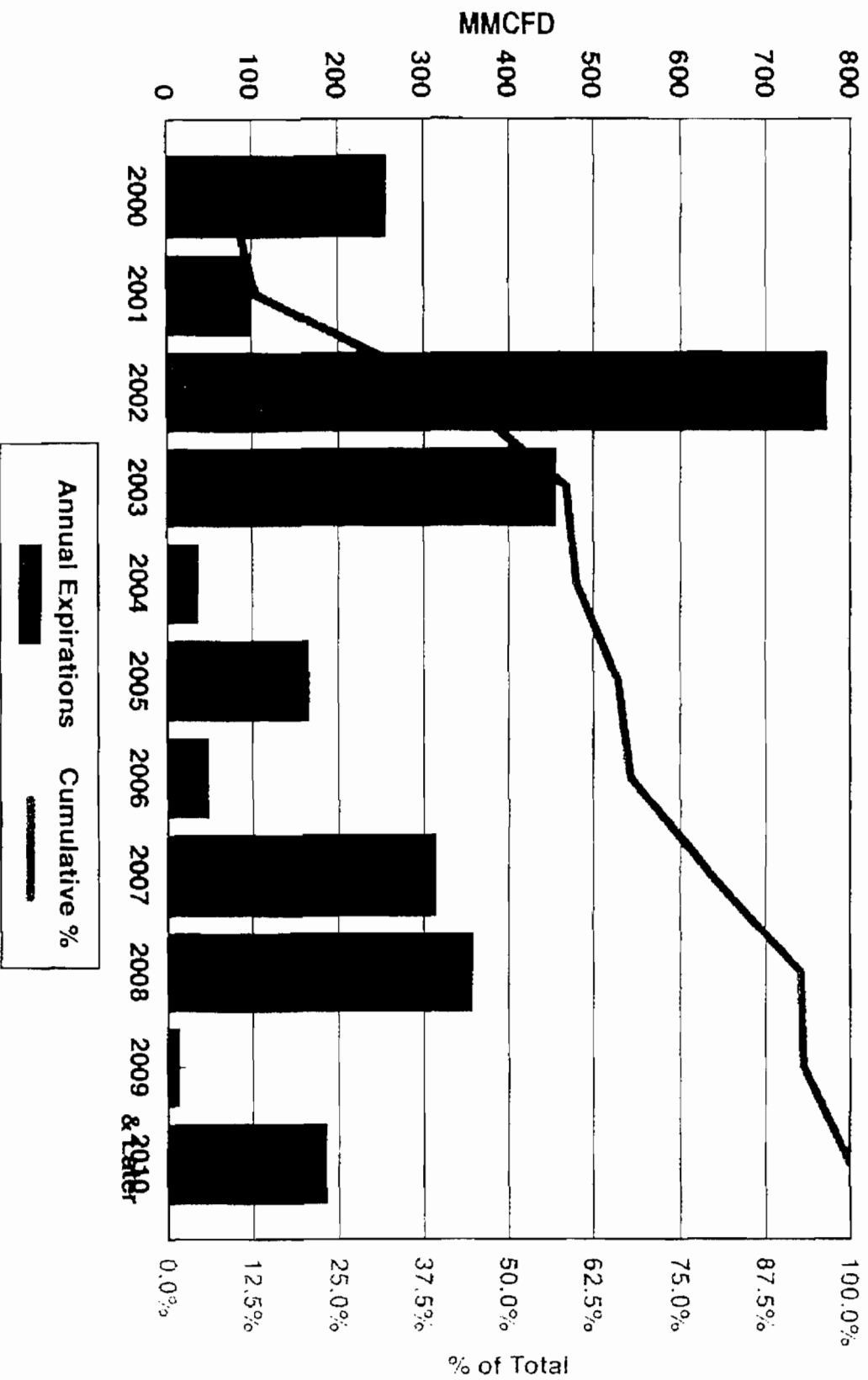
Legend
— Southern Natural Gas
— South Georgia

SNG Pipeline Competition

Exhibit No. SNG - (JCY-3)



SNG Firm Transportation Contracts Yearly Expirations



EXHIBIT

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
FEDERAL ENERGY
REGULATORY COMMISSION

In the Matter of)

Southern Natural Gas Company)

Docket No. CP02-1-002

**REQUESTS FOR REHEARING OF
THE ALABAMA MUNICIPAL DISTRIBUTORS GROUP, THE MUNICIPAL GAS
AUTHORITY OF GEORGIA, AND THE SOUTHEAST ALABAMA GAS DISTRICT**

Pursuant to Rule 713 of the Commission's Rules of Practice and Procedure, the Alabama Municipal Distributors Group, the Municipal Gas Authority of Georgia, and The Southeast Alabama Gas District (hereinafter jointly referred to as the "Municipals") seek rehearing of the September 20, 2002 order issued in the above-captioned proceeding ("September 20 Order").

I. CONCISE STATEMENT OF ERRORS

The Municipals set forth below the statement of errors with respect to the September 20 Order:

- A. The Commission erred in approving the unduly preferential rates for the proposed service to SCS.
- B. The Commission erred in ruling that the discounted rate for SCS will not result in subsidization in contravention of the Commission's Policy Statement.
- C. The Commission erred in not following directly applicable precedent to protect existing shippers from paying for higher fuel costs.

The details of the statement of errors are set forth in the Argument section below.

-2-

II. ARGUMENT

A. The Commission erred in approving the unduly preferential rates for the proposed service to SCS.

1. The Commission failed to justify the particular proposed discounted rates to SCS in contravention of (a) its statutory obligation under Section 7 of the Natural Gas Act to determine that initial rates are in the public interest, (b) judicial mandate that the Commission justify selective discounting and (c) applicable Commission policy and precedents relating to discount adjustments.

Both the Courts and the Commission have stressed the importance of demonstrating the appropriateness of the initial rates that are approved in a section 7 application. The Supreme Court stressed that the Natural Gas Act "requires a most careful scrutiny and responsible reaction to initial price proposals. . . . [Such] proposals must be supported by evidence showing their necessity to the public convenience and necessity' before permanent certificates are issued." Atlantic Refining Co. v. Public Service Com. of N.Y., 360 U.S. 378, 391 (1959). Similarly, the principal focus and emphasis of the Commission's Certification of New Interstate Gas Pipeline Facilities, 88 FERC ¶ 61,227 at 61,748 (1999) (hereinafter, referred to as "Certificate Policy Statement"), order on reh'g, 90 FERC ¶ 61,128 (2000) (hereinafter, referred to as "Rehearing Certificate Policy Statement") was the need to establish the appropriate initial rates for pipeline projects. The Statement also stressed that the applicant has the burden to create the record on which a determination can be made.

The September 20 Order contravenes these mandates by approving, without analysis of the factual contentions raised by Municipals, rates for service to SCS that are significantly less than the tariff rates that Southern charges for the same services. Specifically, the September 20 Order approves (a) an initial \$7.00 per dth reservation charge for the first five years under the contract, which is about 85% of the current applicable tariff rate, (b) a formula rate for the

-3-

remaining 10 years under the contract that can be less than but not exceed the applicable tariff rate and (c) a waiver of the GRI and GSR surcharges. See Exhibit E of the Southern-SCS contract contained in Exhibit I of Southern's Application.

There is no dispute that the rates to SCS are preferential. Nevertheless, the September 20 Order rejects Municipals' contention that there has been no showing that the *particular* proposed rates are unduly preferential. The totality of the Commission's reasoning, found at Paragraph 40 of the order, is as follows:

Here, we will not second-guess Southern's business decision to offer a discount since we believe that Southern had a legitimate, competitive reason to offer a discount —i.e., the shipper, SCS, was telling Southern that it would not subscribe to service at a non-discounted rate. Further, it is reasonable to presume the pipeline will always seek the highest reasonable rate from non-affiliated shippers, since it is in its own economic interest to do so. The Municipals have not offered reasons why Southern would not seek the highest possible rate.

The Commission must reverse this ruling which constitutes nothing less than an abdication of its statutory mandate under Section 7 of the Natural Gas Act to determine rates that are required by the public convenience and necessity. The September 20 Order provides no support for the *particular* rates proposed. The only basis rooted in fact is that SCS requested a discounted rate. According to the September 20 Order, that fact alone would justify *any* initial rate, no matter how deeply discounted, as being required by competitive circumstances. This leap of faith is no substitute for the showing—required under Section 7 of the Act—that the *particular* proposed rates were in fact required by the public convenience and necessity. Atlantic Refining, supra.

Moreover, the failure of the Commission to justify the proposed discounted rate also contravenes the repeated judicial recognition that selective discounting must be justified by the

particular factual situation. Associated Gas Distributors v. FERC, 824 F.2d 981 at 1011-12 (D.C. Cir. 1987); *see also* Mississippi Valley Gas Company v. FERC, 68 F.3d 503 at 507 (D.C. Cir. 1995).

The rationale of the September 20 Order for failing to fulfill its mandate to justify the particular proposed preferential rates—the presumption that the pipeline will always seek the highest rate from a non-affiliated shipper—is obviously invalid. The presumption is not only unsupported, but directly inconsistent with Commission policy and *specific findings*, in the context of when a discount adjustment is appropriate, that pipelines do not always provide discounts to non-affiliated shippers for competitive reasons. For example, in its Policy Statement Providing Guidance with Respect to the Designing of Rates, 47 FERC ¶61,295 at 62,057 (1989) order on reh'g, 48 FERC ¶61,122 (1989) (“Rate Design Policy Statement”) the Commission stressed its concern that such selective discounts “that have the potential for giving rise to undue discrimination. . . .”

In determining whether a discount is required by competition in deciding whether a discount adjustment is appropriate, the Commission does provide for an *initial* presumption that pipelines will always seek the highest rate from a non-affiliated shipper *if* the pipeline generally explains the basis for the discounts. Iroquois Gas Transmission System L.P., 84 FERC ¶61,086 at 61,476-77 (1998); and Trunkline Gas Company, 90 FERC ¶61,017 at 61,092-93 (2000). Even then, “once evidence has been introduced raising reasonable questions concerning whether competition in fact required the discounts . . . the pipeline must provide sufficient evidence concerning why it granted the *specific* discounts in question. . . .” *Id.* Indeed, in Iroquois and Trunkline, the Commission specifically rejected proposed discount adjustments based on the

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failure of the pipeline to show that the *specific* discounts to non-affiliated shippers were justified by competition.

The invocation by the September 20 Order of a conclusive presumption that any discounted rate to a non-affiliated shipper is by definition justified is patently inconsistent with the above-discussed Commission policy and precedents.

Indeed, application of these policy and precedents to the pleadings in this case compels the determination that the proposed discounted rates to SCS had not been justified. To begin with, in its certificate application Southern provided no explanation for its proposed discount to SCS other than a one-sentence conclusory assertion that the discount was necessary to induce SCS to locate generation load on Southern. Municipals November 1, 2001 Protest at 4. When the Municipals protested the absence of any explanation for the discount (*id.*), Southern responded by providing a general explanation of the initial \$7/dth reservation rate. Southern's November 16, 2001 Pleading at 7 - 10.

As Municipals demonstrated, this late-filed explanation raised many questions concerning the appropriateness of the \$7/dth rate. Municipals' December 6, 2001 Pleading at 4 - 8. For example, Southern's first justification was that Transco's rolled-in rate was lower than Southern's rolled-in rate. Yet, this point was obviously irrelevant to any discount Southern would provide to SCS in light of the fact that the Certificate Policy Statement required Transco to price system expansions on an incremental basis, a fact confirmed by Southern when it acknowledged that Transco had priced all projects on an incremental basis since the issuance of the Certificate Policy Statement. *Id.* at 4 - 5.

Southern's next attempted justification for the \$7/dth rate was that Transco was offering unidentified shippers unidentified negotiated rates, and that Transco offered an undisclosed

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discount to SCS. Yet, as the Municipals demonstrated, Southern provided only a description of the variables it considered in deriving its \$7/dth proposal to SCS, and provided no specific information that would provide *any* basis for the Commission to determine whether the \$7/dth rate was competitively required. *Id.* at 6.

Moreover, *as Southern conceded*, the rate that Transco offered was only one of a number of factors that had to be considered to determine the rate that Southern would be required to offer to make it more economical to locate new generation on Transco or Southern. Southern's November 16, 2001 Pleading at 9 - 10. Indeed, *as Southern also conceded*, there were economic advantages for the generation site on SCS as compared to Transco—e.g., (1) in Southern's words, that Southern had "an historically verifiable gas price advantage . . . over prices on the Transco system," (*id.* at 9), and (2) that there should be savings associated with the location of the plant on the Southern system because the site was already being developed for other SCS generation and there were electric transmission lines already being built to the site (*id.* at 9 - 10). Yet, Southern did not provide *any* explanation of how or the extent to which it took into account the verifiable gas savings of locating a plant on Southern. Moreover, Southern simply dismissed the potentially huge cost savings associated with an existing infrastructure on the Southern system on the unexplained and unsupported assertion that it found no quantifiable competitive advantage. Municipals' December 6, 2001 Pleading at 4 - 7.

As the Municipals also demonstrated, there were other factors that required analysis to determine whether there was need to offer a specific discount to SCS. For example, the generation sites on Southern might be closer to SCS' transmission lines or closer to the ultimate purchasers of the output of the plant than the site on the Transco system. The generation sites on Southern might also present fewer or less significant environmental problems that might be less

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expensive to address. All of these factors could enable Southern to charge *more* than Transco for transportation. Yet, Southern had not provided *any* information on *any* of these factors; indeed, Southern had not provided such basic information as the name or location of the Transco alternative site. *Id.* at 6 - 7.

Southern deigned not to provide any response to these numerous questions concerning the reasonableness of the specific discounted rate proposed for service to SCS. Against this backdrop, the ruling of the September 20 Order that the preferential rates are justified, indeed required by the public interest, is manifestly inconsistent with the above-discussed policy and precedents and clearly untenable.

Finally, the ruling of the September 20 Order that Municipals had failed to provide any reason why Southern would not seek the highest rate is ill-founded both factually and legally. It is legally wrong as demonstrated by the above discussed precedent on discount adjustments, and more importantly, because under Section 7 of the Act the burden is on Southern to justify the clearly preferential rates, and not on the Municipals to demonstrate otherwise. It is factually wrong because it disregards the *repeated* demonstration of the Municipals that it is unreasonable to conclude that Southern would always seek the highest rate given the diversified interests of SCS and Southern. As the Municipals stressed (November 1, 2001 Protest at 8; fn. reference omitted):

[T]he companies involved are members of corporate families with highly diversified interests extending well beyond the rates at which Southern will provide transportation to new powerplant load. The discounted transportation rates that Southern has agreed to may be the product of Southern's efforts to attract load, or they may be compensation for commercial arrangements that have nothing to do with transportation on the Southern system.

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The Municipals repeated this same point at pages 7 - 8 of its December 6, 2001

Supplemental Protest and then concluded (emphasis added):

Given that Southern can exchange a discounted rate for Southern transportation in return for a consideration in a different and unrelated context, the *only* check to ensure that the discounted rates to SCS were the highest that could be obtained is to require Southern to demonstrate this fact. The clear failure of Southern to make this demonstration, despite continued opportunities to do so, confirms that the Commission cannot approve these preferential rates.

2. **The Commission contravened the mandate of Section 7 and the requirements of its Certificate Policy Statement to determine whether the discounted rates provide an overall benefit to Southern's customers.**

Even assuming that the preferential rates are required to attract the new SCS load, such rates have still not been shown to be required by the public interest. As the Commission is well aware, the rationale for selective discounting is that existing customers of a pipeline would benefit by the reduction in rates to the extent that the discounted shippers also contribute to recovery of the fixed costs of the pipeline. Rate Design Policy Statement, 47 FERC at 62,056.

Both the APGA and the Municipals November 1, 2001 Protests demonstrated that the discount would produce *detriments* which the September 20 Order failed to analyze.

Specifically, at pages 3 - 4 of its protest, APGA demonstrated that an increase in power plant load has clear adverse effects on the price of natural gas. As APGA noted, numerous articles in national news publications have confirmed industry common knowledge that the spike in natural gas prices during the winter of 2000- 2001 were caused in notable part by the substantial increase in the demand for natural gas by power plant load. While gas prices have fallen recently from those spectacular price spikes due in large measure to depressed industrial gas demand resulting from a slumping economy, the significant increase in gas usage to meet new electric generation can only have a substantial and adverse impact on the long-term prices of

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natural gas for all consumers. Virtually every power plant now being constructed relies either primarily or exclusively on natural gas to generate electricity. Most of the predicted growth in gas consumption (up to the oft-heard number of 30+ Tcf) is attributable to the electric power industry. ^{1/} The adverse effect on price of natural gas that must be paid by Southern's existing customers is a real and significant factor in determining whether it is in the public interest to reduce rates to attract SCS' electric generation load onto its system.

The Municipals November 1, 2001 protest also demonstrated that the discount to SCS would produce another detriment by building new facilities that would exacerbate the capacity turn-back crisis that Southern had discussed at great length and passion in sworn testimony. Municipals protest at 11 - 13. ^{2/}

Obviously, if the preferential rates produce a net detriment to the Southern system, they cannot be approved. This conclusion is mandated not only by logic but by the clearly applicable judicial precedent of Maryland People's Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985), and Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985). In these decisions, the D.C. Circuit repeatedly struck down certificates that were preferential to certain customers precisely because the Commission had refused to determine whether the particular program presented a net benefit to existing customers.

Moreover, as stressed in the protests of both the Municipals and APGA, the Commission as a separate matter is required under its own Certificate Policy Statement to conduct a broad

^{1/} According to the Gas Technology Institute, gas demand for electric generation was 202 Bcf in 1999 and 653 Bcf in 2000. The Gas Technology Institute forecasts a large growth in demand in 2001, 2002, and 2003. Demand for gas-fired electric generation will be 1,110 Bcf, 1,552 Bcf, and 2,077 Bcf, respectively. Gas Daily, March 1, 2001 at 8.

^{2/} The exacerbation of the capacity turn back crisis is also discussed infra at 13 - 15.

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inquiry into precisely the concerns raised in the protests. Municipals' November 1, 2001 Protest at 8; APGA's November 1, 2001 Protest at 5. Indeed, the Certificate Policy Statement requires that the Commission determine that the benefits outweigh the detriments of the proposed project (Certificate Policy Statement, supra, at 61,745), and places the burden on the applicant to create a record that will enable the Commission make this determination (id. at 61,748).

Southern has clearly failed to provide any record—and there is no record—that analyzes the detriments of the proposed discounted rates and weighs them against the benefits. Instead, in contravention of the Commission Certificate Policy Statement, the September 20 Order simply disregarded the demonstration of APGA and the Municipals that there were detriments associated with the proposed discounts to SCS that required analysis.

B. The Commission erred in ruling that the discounted rate for SCS will not result in subsidization in contravention of the Commission's Policy Statement.

As the Municipals stressed at pages 9 - 14 of their November 1, 2001 protest, the discounted rates to SCS will require Southern's existing customers to subsidize the service to SCS, which is in violation of the threshold requirement of the Certificate Policy Statement. 88 FERC at 61,747. At Paragraph 27 of the September 20 Order, the Commission rejected this position by relying on Exhibit N of Southern's amended application that demonstrated, according to the Commission, that the incremental revenues from the project will exceed the incremental costs. As further justification, the Commission cites two precedents when the same protest was raised and rejected. Finally, the September 20 Order notes that issues related to the level of any discount adjustment can be addressed in Southern's next rate case.

These rulings are flawed in several respects. To begin with, the analysis by the September 20 Order of Exhibit N is based on a fundamentally incorrect assumption—that the

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incremental costs of the facilities are the total costs for the service to be provided. The Certificate Policy Statement rejected this very assumption with respect to inexpensive capacity expansions. According to the Commission, "[i]n that instance, because the existing customers bear the costs of the earlier, more costly construction in their rates, incremental pricing could result in the new customers receiving a subsidy from existing customers because the new customers would not face the full cost of the construction that makes their new service possible." Certificate Policy Statement at 61,746.

Indeed, the Commission has implemented this aspect of the Certificate Policy Statement by requiring the roll-in of inexpensive expansions precisely because it was necessary to avoid subsidization by existing customers. For example, as the Commission ruled in Transwestern Pipeline Company, 90 FERC ¶ 61,032 at 61,162 (2000), reh'g denied, 92 FERC ¶ 61,035 (2000) (emphasis added):

The Certificate Policy Statement provides that expansion project costs should be rolled into the rates of existing customers in cases where the inexpensive expansion of facilities was made possible because of prior costly construction and rolled-in rates would result in lower rates for the existing customers. . . . Thus, if rolled-in pricing will result in reduced rates for existing customers . . . we will require Transwestern to roll the . . . expansion costs into the rates of its customers in its next rate case. *Otherwise, the expansion shippers will receive a subsidy from the existing customers.*

Charging a full rolled-in rate for service to SCS is required for precisely this reason. As the Commission well knows, the cost of pipeline construction has increased significantly, particularly since the construction of Southern's mainline facilities. Southern has not found new material for its capacity additions that is less expensive than the depreciated cost of existing facilities. Nor has Southern struck a bargain with contractors to reduce labor costs. The *only*

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reason why the revenues of the service to expansion shippers will exceed its incremental costs is that the service depends on existing costlier capacity for which existing customers have paid and are paying. Accordingly, at Paragraph 33 of the September 20 Order the Commission properly required a roll-in of rates to prevent existing customers from subsidizing the project.

Yet, the same order then created a subsidy by allowing Southern to charge less than the rolled-in rates. There simply is no rational basis for the Commission ruling. If rolled-in rates are required to eliminate subsidization by existing customers of the new service, any reduction in rolled-in rates creates the very subsidy that the Policy Statement prohibits.

In the September 20 Order the Commission does not address the merits of Municipals' arguments, but simply refers to precedents in which the Commission rejected the same argument. Yet, at page 11 of their November 1, 2001 protest, the Municipals had already acknowledged the existence of such precedents, but demonstrated that these rulings are inconsistent with the reasoning of the Certificate Policy Statement that charging expansion shippers less than the rolled-in rates constitutes inappropriate subsidization.

While the Municipals have already demonstrated this inconsistency above and in its November 1, 2001 Protest, the following example confirms the inconsistency beyond debate. Assume that a pipeline proposes an incremental rate of \$1/dth, which reflects the incremental cost of a new project, and that the existing rolled-in rate is \$2/dth. Commission policy requires that the pipeline charge the \$2/dth to avoid a subsidy that would otherwise exist because the true cost of the new service includes the cost of existing facilities. Now assume that the pipeline knows of Commission policy and proposes a rolled-in rate, except that it will discount that rate down to \$1/dth. The same subsidy exists with respect to the proposed \$1/dth rate in either situation—and for the same reason. The cost of the new facilities—which in both examples is the

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same because the facilities are the same—is immaterial. The service to be provided—which is the same in both examples—would be made possible by existing facilities. Accordingly, the full rolled-in rates would be required to avoid a subsidy to the new service. There is no other logical result.

As the Municipals demonstrated at pages 11 - 13 of their November 1, 2001 protest, the need for the Commission to require SCS to pay full rolled-in rates is compelling when assessed in the context of the Southern system. *As Southern has stressed*, it will shortly be in a capacity turnback crisis at the expiration of customer contracts. Southern's President, James C. Yardley, testified to this problem at considerable length and passion in Southern's latest rate case in Docket No. RP99-496. *See* Direct Testimony of James C. Yardley at pages 5 - 11. 3/

The risk of capacity turnback was for Southern a driving force underlying the settlement approved in Docket No. RP99-496. All of Southern's customers were provided a significant rate reduction below current rates in exchange for a commitment to extend their contracts until October 31, 2005. In addition, Atlanta Gas Light Company ("Atlanta"), historically the largest customer on the system, was provided with several sizeable discounts that dwarfed any other discount provided by the settlement. *See e.g.* March 10, 2000 Offer of Settlement, Article V, Section 7 of the Stipulation and Agreement in Docket No. RP99-496.

The apparent rationale for these large discounts was the risk that there would be a substantial reduction in the capacity presently contracted for by Atlanta following the transfer of that capacity to marketers. Such a reduction could arise not only if the marketers contracted with Southern's competitors for some of their capacity, but simply because the marketers might desire

3/ For convenience, the relevant excerpt of Mr. Yardley's testimony is provided as the Attachment hereto.

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less capacity. *See e.g.* Direct Testimony of James C. Yardley at pages 8 - 10. (At page 9: "[T]he future level of [Atlanta]'s transportation contracts and the term of those contracts are very uncertain." At page 9: "Southern expects intense competitive pressure as marketers strive to reduce their costs by retaining (or causing [Atlanta] to retain) no more FT than is absolutely necessary." At page 10: "A number of these marketers . . . have stated that [Atlanta] has too much firm transportation capacity under contract and that [Atlanta] should no longer hold the level of pipeline firm transportation contracts that are currently subscribed."

The risk of capacity turnback as of October 2005 applies not only to Atlanta, but to all firm transportation customers of Southern—apart from its captive customers that would bear the burden of spiraling increases in rates due to capacity turnback. This risk clearly heightens the burden on Southern to justify discounts to build additional capacity on the Southern system to be in service as of June, 2003 and May, 2004 for Phase I and Phase II, respectively, i.e., shortly before *Southern* anticipates it will be in a capacity turnback crisis.

The discounting of rates for capacity that, consistent with *Southern's* fears, may well soon be excess to its needs must be a concern to the Commission, given its emphasis in the Certificate Policy Statement Rehearing that the prohibition against subsidization is necessary to protect against overbuilding (Certificate Policy Statement Rehearing, *supra* at 61,392; emphasis added):

The removal of the subsidy is necessary to ensure that the market finds the project is viable because either the pipeline or its expansion shippers are willing to fully fund the project. *Having lower prices subsidized by existing customers can lead to overbuilding as new customers are willing to subscribe to the capacity only because the price of the capacity is subsidized.*

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As the Commission recognized, the willingness of the pipeline to step up to the plate and propose rates for the project without financial subsidy is an important indicator of the market-based need for the project. Certificate Policy Statement, supra at 61,747. Yet, with respect to the capacity that would be built to serve SCS, Southern will *not* assume *any* risk. If, consistent with Southern's fears, such capacity produces a level of system capacity well in excess to its needs, Southern will simply file system-wide rates reflecting the cost of the excess capacity.

It cannot be overemphasized that Southern's captive customers will bear these additional costs of future unsubscribed capacity and any additional discount adjustments created by the excess capacity induced by Southern's discounted rates to SCS. The inequity to these customers is underscored when it is recalled that under Southern's proposals these same customers will be required to fund the severely discounted rates to SCS. In this manner, Southern's proposed rates contravene another principal goal of the Certificate Policy Statement, which is to protect captive customers. See Certificate Policy Statement, supra at 61,744 - 45.

Finally, the Municipals note that the statement in the September 20 Order that issues related to the level of discount adjustment are irrelevant to the Commission's determination as to whether the proposed discounted rates to SCS provide for a subsidization prohibited by the Policy Statement.

C. The Commission erred in not following directly applicable precedent to protect existing shippers from paying for higher fuel costs.

At pages 13 - 14 of our November 1, 2001 protest, the Municipals protested that existing customers are not protected from paying increased fuel costs prompted by the massive generation load of the expansion shippers, citing PG&E Gas Transmission Northwest Corp., 96 FERC ¶61,194 (2001), order on reh'g, 97 FERC ¶61,101 (2001). In these cited orders, in response to a

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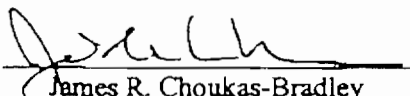
similar protest, the Commission directed the pipeline to establish a surcharge for expansion shippers that would protect against the existing shippers incurring any additional fuel costs. *See also Kern River Gas Transmission*, 96 FERC ¶ 61, 137 (2001). In doing so, the Commission noted that it had made no determination that fuel costs would actually increase, but was obligated by the Certificate Policy Statement to provide such protection.

Southern collects fuel costs by imposition of a fuel retention percent. *See* Sheet Nos. 15 - 18 of Seventh Revised Volume No. 1 of Southern's FERC Gas Tariff. The Certificate Policy Statement is equally applicable here and would likewise require the Commission to protect against any increase in fuel costs either in price or increase in fuel retention percent that would be caused by the proposed facilities or expansion load.

WHEREFORE, for the foregoing reasons, the Municipals request rehearing of the September 20, 2002 order.

Respectfully submitted,

THE ALABAMA MUNICIPAL DISTRIBUTORS
GROUP, THE MUNICIPAL GAS AUTHORITY
OF GEORGIA, AND THE SOUTHEAST
ALABAMA GAS DISTRICT

By 
James R. Choukas-Bradley
Joshua L. Menter
Miller, Balis & O'Neil, P.C.
Suite 700
1140 Nineteenth Street, N.W.
Washington, D.C. 20036

Their Attorneys

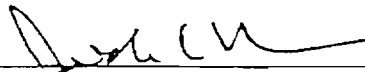
October 17, 2002

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each of the parties shown on the official service list compiled by the Secretary of the Commission in this proceeding.

Dated at Washington, D.C., this 17th day of October 2002.

By



Joshua L. Menter
Miller, Balis & O'Neil, P.C.
Suite 700
1140 Nineteenth Street, N.W.
Washington, D.C. 20036
(202) 296-2960

ATTACHMENT

Exhibit No. SNG-____ (JCY-1)
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Natural Gas Company) Docket No. RP99-____-000

PREPARED DIRECT TESTIMONY
OF
JAMES C. YARDLEY
ON BEHALF OF
SOUTHERN NATURAL GAS COMPANY

1 Q. Please state your name, position, and business address.

2

3 A. My name is James C. Yardley. I am President of Southern Natural Gas Company
4 ("Southern"). My business address is the AmSouth-Sonat Tower, 1900 5th Avenue
5 North, Birmingham, Alabama 35203.

6

7 Q. Please briefly state your education and professional background.

8

9 A. I graduated from Duke University in 1973 with an undergraduate degree in Economics. I
10 subsequently received an MBA from Harvard Business School in 1978. I was employed
11 by Southern beginning in 1978 in the Corporate Planning Department. I subsequently
12 held various management and senior management positions in the Planning, Marketing,
13 Business Development, and Executive areas of Southern and other Sonat Inc. subsidiaries
14 prior to appointment to my present position in May 1998.

15

16 Q. What are your responsibilities as President of Southern?

17

1 pipelines. Primarily as a result of these factors, Southern's principal pipeline competitor,
2 Transco, has significantly lower filed rates than Southern in its major market areas as set
3 forth below:

	<u>FT Reservation Charges</u> \$/Dth		
	<u>Alabama</u>	<u>Georgia</u>	<u>South Carolina</u>
Transco (from Transco Station 85/ Mobile Bay line)	\$5.18	\$5.18	\$7.79
Southern (current settlement rates)	\$8.62	\$11.37	\$11.37

4
5 Q. Has Transco evidenced a willingness to expand its pipeline into the Southeastern United
6 States?

7
8 A. In the five years since the end of Southern's last rate case, Transco has announced or
9 placed in service six pipeline expansions, with total firm capacity of over 600,000 mcf/d
10 into the Southeast and Mid-Atlantic states. These expansions included an additional
11 400,000 mcf/d of firm service into Alabama, Georgia, and South Carolina, Southern's
12 major market areas. Southern's shippers have often subscribed for Transco's competing
13 expansions. We expect this trend to continue as indicated in Transco's April 15, 1999
14 announcement of a proposed Sundance Expansion to serve markets in Alabama, Georgia,
15 and the Carolinas. What this means for Southern is continuing competitive pressures to
16 provide rate discounts to retain existing loads as well as increasing risk of loss of existing
17 loads to new expansion projects.
18

1 Q. Has competition with Transco intensified in recent years?

2
3 A. Yes, it has. By shifting some of its expansion costs to its firm shippers in the Mid-
4 Atlantic and Northeastern states, Transco has been able to aggressively expand its
5 pipeline to serve additional Southeast markets in the last several years. Transco's recent
6 SouthCoast Expansion Project, for example, which provides an additional 61,600 dth/d of
7 firm transportation service to AGLC, is priced on a rolled-in rate basis. Transco has
8 recently announced that it will seek rolled-in rates for its proposed Sundance expansion
9 into the Southeast.

10
11 By contrast, many of Transco's earlier system expansions were priced on an incremental
12 rate basis. For example, Transco's SunBelt Project, which was placed in service in 1997,
13 provided an additional 75,700 mcf/d of firm transportation service to South Carolina
14 Pipeline at a weighted average incremental reservation rate of approximately \$12.30/dth.
15 Transco has recently announced its intention to propose roll-in of the SunBelt Project in
16 Transco's next general rate case. See Answer of Transcontinental Gas Pipe Line
17 Corporation to Comments, Requests for Conditions and Protests filed June 24, 1999, in
18 *Transcontinental Gas Pipe Line Corp.*, Docket No. CP99-392-000, p. 9. The rolled-in
19 rate to South Carolina Pipeline, Southern's third largest customer, is likely to be in the
20 range of \$9.50 to \$10.00/dth.

21
22 Q. Are there other pipeline competitors in Southern's major markets?

23

(JCY-1)

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1 A. Yes, there are. A number of Southern's pipeline competitors are shown on the map
2 attached as Exhibit No. SNG-_____ (JCY-3) to this testimony. East Tennessee Natural
3 Gas currently provides approximately 45,000 mcf/d to Chattanooga Gas Company in
4 Tennessee and 59,000 mcf/d to AGLC in northwest Georgia. In addition, Columbia Gulf
5 Transmission and MCN Energy Group Inc. announced in April 1999 an open season
6 offering of up to 250,000 dth/d of capacity in the Volunteer Pipeline, a proposed new
7 pipeline to extend from an interconnection with Midwestern Gas Transmission near
8 Portland, Tennessee to an interconnection with AGLC near Chattanooga, Tennessee to
9 serve markets in Georgia and the Southeast. Finally, in 1997, AGL Resources, Inc. and
10 Transco announced a joint venture for a new pipeline, called the Cumberland Pipeline, to
11 provide additional service from Transco's interstate pipeline into the northern Atlanta
12 metro region and northern Georgia. While this project ultimately did not go in service, it
13 is indicative of the continued high-level interest by existing and potential pipeline
14 competitors to provide additional gas service into the Southeast.

15
16 Other competitors include Florida Gas Transmission Company (FGT) and Koch Gateway
17 Pipeline Company (Koch), which currently provides pipeline service in southeast
18 Alabama. Significantly, FGT's western division reservation rate of \$2.44/dth extends
19 through southern Alabama to the Alabama-Florida state line, where FGT's market area
20 rate zone begins. Similarly, Koch's FT reservation rate in southeast Alabama is
21 \$5.84/dth. Both of these rates compare favorably with Southern's current settlement
22 Zone 2 FT reservation rate of \$8.62/dth. Other potential competitors include Duke
23 Energy, which has announced plans to build the Sawgrass Energy Transmission System

(JCY-1)

Page 8 of 16

1 from southeastern Alabama, across Mobile Bay, and through the Florida panhandle into
2 peninsular Florida.
3

4 Q. Please describe Southern's transportation contracts.
5

6 A. Southern is currently fully subscribed in its major market areas (Zones 2 and 3). By the
7 end of 2002, approximately 42% of our existing firm contracts (measured by
8 transportation demands) will come up for renewal as shown in Exhibit No. SNG-____
9 (JCY-4). The weighted average remaining term of Southern's long-term firm
10 transportation contracts is only 4.8 years (as of March 1, 2000). Exhibit No. SNG-____
11 (JCY-5). This compares with an average remaining term for U.S. pipelines in excess of 8
12 years for all firm contracts, and in excess of 10 years for long-term firm contracts.
13 Energy Information Administration, *Natural Gas 1998: Issues and Trends*, pp. 132-133
14 (June 1999). With the level of competition from other pipelines, Southern will face
15 strong challenges to maintain its existing load. This is evidence of the high level of
16 business risk that Southern faces.
17

18 Q. What other factors affect the recontracting risk that Southern faces?
19

20 A. AGLC is Southern's largest customer, representing approximately 40% of Southern's
21 total revenues. By October 1999, AGLC will have completely unbundled its system and
22 exited the gas merchant function. This unbundling, which was initiated following the
23 passage of legislation in Georgia in 1997, has proceeded at a pace that has been

1 unprecedented in the industry. Indeed, AGLC will be the largest, fully unbundled LDC
2 in the nation by October.

3
4 Southern has contracts with AGLC for over 600,000 Mcf/d of firm transportation demand
5 which come up for renewal in August 2002. What AGLC's unbundling means for
6 Southern is that the future level of AGLC's transportation contracts and the term of those
7 contracts are very uncertain. As the American Gas Association recently observed in
8 assessing the impact of state unbundling on LDC contracting decisions:

9 Uncertainty about the future level of demand, who their customers will be,
10 and the potential treatment of stranded costs makes many LDCs reluctant
11 to contractually commit to [pipeline] capacity for any significant period of
12 time.

13
14 American Gas Association, *The Changing Nature of Pipeline Capacity Contracts and the*
15 *Potential for Future Capacity Turnback by Local Distribution Companies, January 1998,*
16 p.15.

17
18
19 Q. Does AGLC's unbundling have other effects on Southern?

20
21 A. Yes. Not only is the overall level of FT service likely to change, but also the type of
22 services which marketers utilize to provide gas service to the end-use customers. Thus,
23 Southern expects intense competitive pressures as marketers strive to reduce their costs
24 by retaining (or causing AGLC to retain) no more FT than is absolutely necessary, and
25 substituting other services, such as capacity release and IT, wherever possible. In
26 addition, Southern will face additional competition from the marketers themselves, who
27 can rebundle transportation and storage services on several pipelines with the gas
 commodity to provide a delivered market area service, often with greater flexibility in

(JCY-1)
Page 10 of 16

1 price and terms than the tariff-based services that an interstate pipeline must offer. A
2 number of these marketers, such as SCANA, have publicly stated their views that AGLC
3 has too much firm transportation capacity under contract and that AGLC should no
4 longer hold the level of pipeline firm transportation contracts that are currently
5 subscribed. See, Motion to Intervene and Protests of SCANA Energy Marketing, Inc., p.
6 5-9, filed May 27, 1999, in *Transcontinental Gas Pipe Line Co.*; Docket No. CP99-392.
7 This means even greater competitive and decontracting pressures for Southern which
8 further exacerbate Southern's business risks.

9
10 Q. But isn't the recontracting risk mitigated by the growing demand for gas in the
11 Southern's major markets?

12
13 A. Only to some extent. It is true that gas demand in the Southern's major markets
14 (Alabama, Georgia, and South Carolina) is growing at a rate faster than the national
15 average (an average annual rate of 3.1% over the last 10 years compared to 2.6%
16 nationally). Energy Information Administration, *Historical Natural Gas Annual 1930*
17 *through 1997*, pp. 230, 250. Southern has been fortunate to secure a portion of that
18 growth through market expansions. But due to intense pipeline competition as described
19 above, Southern faces a decreasing likelihood that it will be able to continue to capture a
20 meaningful portion of the market growth, or that it will be able to retain the existing level
21 of business on its pipeline.

22

1 As I have previously stated, approximately 42% of Southern's current long-term FT
2 contracts will expire by the end of 2002. The conditions in its markets make the renewal
3 of these contracts far from certain. And Southern's experience indicates that most
4 renewals will be for relatively short terms. Failure to renew or resubscribe even 10% of
5 the contracts that end by 2002 could mean an annual reservation revenue loss to Southern
6 of as much as \$17.5 million. These recontracting risks are particularly acute in light of
7 the structural, cost, and rate differences between Southern, a distribution-like system, and
8 Transco, a long-line pipeline with whom we compete.

9
10 Q. Does cost-of-service rate regulation mitigate the pipeline's financial risks of turnback?

11
12 A. No. In assessing the business risks that Southern faces, it should be noted that the FERC
13 has not insured full-cost recovery for interstate pipelines that have faced significant
14 capacity turnbacks from current customers. Rather, FERC's approach in the rate cases of
15 El Paso Natural Gas Company, Transwestern Pipeline Company, and Natural Gas
16 Pipeline Company of America has been to encourage pipelines to remarket turnback
17 capacity. Regardless of the merits of FERC's position, the agency has nonetheless made
18 it clear that pipelines should not expect full recovery of all costs of turnback capacity. As
19 a result, Natural, El Paso, and Transwestern entered into settlements in which the
20 pipelines assumed significant risks of remarketing the turnback capacity. So it is a risk
21 that we take very seriously at Southern.
22

(JCY-1)
Page 12 of 16

1 Q. How does Southern's average remaining contract life compare with the depreciable life
2 of its pipeline system?

3
4 A. Under the FERC's approach to turnback capacity and its cost-of-service ratemaking,
5 Southern has no assurance that it will be able to fully recover the cost of its facilities.
6 This is because depreciation rates are generally not set based on the life of the contracts.

7
8 The weighted average life of Southern's firm transportation contracts is 4.8 years (as of
9 March 1, 2000). Yet, Southern's pipeline transmission facilities, which comprise the
10 bulk of its rate base, are depreciated over a 50 year period based on a 2% composite
11 annual depreciation rate that is applied to gross plant. As Ms. Hardy's testimony
12 indicates, Southern's net plant is approximately \$1.1 billion. At an annual depreciation
13 and amortization expense of approximately \$50 million, which Southern proposes in this
14 rate proceeding (see Exhibit No. SNG-_____ (TSH-2) p. 2), Southern's pipeline system
15 will have a depreciable life of approximately 22 years. The significant gap between
16 Southern's remaining average firm transportation contract life of only 4.8 years and its
17 remaining pipeline depreciable life of 22 years represents a very substantial business risk.
18 Looking forward, Southern's investors face approximately 17.2 years of depreciation
19 expense and fixed cost recovery not covered by contracted revenues.

20
21 Q. Is the risk of remarketing turnback capacity unique to Southern?

22

(JCY-1)

Page 13 of 16

1 A. No, but I believe it is more significant for Southern than other pipelines in general for
2 several reasons. First, the average remaining term of Southern's long-term firm contracts
3 is only 4.8 years – less than half of the national average, as I've explained. Second,
4 AGLC's unbundling has progressed faster and farther than any other state LDC
5 unbundling in the country. AGLC will be completely unbundled and out of the merchant
6 function within the next two months. This will result in additional pressures by retail
7 marketers – who have clearly indicated their views that AGLC has “too much” pipeline
8 FT capacity – for AGLC to reduce the level of FT held and to seek lower cost
9 alternatives. Third, while Southern provides a valuable distribution-like service, its
10 system configuration also results in a higher per unit cost structure than its long-line
11 competitors who are able to cherry pick major loads in Southern's principal market areas.
12 Thus, while other pipelines may face capacity turnback risks, the recontracting risks for
13 Southern are greater than the risks faced by other pipelines in general.

14
15 Q. Does Southern have other business risks?

16
17 A. While the degree of recontracting risk and the level of pipeline competition are the
18 principal risks, Southern also faces a significant risk in recovering the approximately
19 \$11.8 million of fixed costs that have been allocated to Southern's interruptible
20 transportation service. As described in Mr. Outlaw's testimony, capacity release is very
21 competitive with Southern's interruptible transportation (IT) service, and it will present a
22 substantial challenge for Southern to achieve the levels of IT throughput that are

EXHIBIT

E

ORIGINAL

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ep Southern
Natural Gas
an El Paso Company

2 of 3

2004 AUG 31 A 11:32

FEDERAL ENERGY
REGULATORY COMMISSION

August 31, 2004

Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Attention: Ms. Magalie R. Salas, Secretary

RE: Southern Natural Gas Company
Docket No. RP04- 523 - 000

Ladies and Gentlemen:

Pursuant to the Federal Energy Regulatory Commission's 18 CFR § 154.4 (a), Southern Natural Gas Company (Southern) herewith submits a compact disc ("CD") containing Southern's electronic version of its Section 4 rate filing.

The enclosed CD is labeled "Southern Natural Gas Company, Rate Case Filing" and contains a directory labeled 007A0408. The directory contains Statements and Schedules A - P.

Should there be any questions regarding electronic files, formats, etc., please contact Debbie Hendrix by phone at (205) 325-7390, or by e-mail at debbie.hendrix@elpaso.com.

Respectfully submitted

SOUTHERN NATURAL GAS COMPANY


Glenn A. Sheffield
Director - Rates

①

CD - Rom / OMTR

FILED
OFFICE OF THE
SECRETARY

2004 AUG 31 A 11:32

FERC
REGULATORY COMMISSION

SOUTHERN NATURAL GAS COMPANY

DOCKET NO. RP04- 523-000

NOTICE OF RATE CHANGE

VOLUME 3

Exhibit No. SNG - ____ (GAS-1)

Page 1 of 40

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Natural Gas Company

)
)
)

Docket No. RP04-____-000

PREPARED DIRECT TESTIMONY
OF
GLENN A. SHEFFIELD
ON BEHALF OF
SOUTHERN NATURAL GAS COMPANY

I.

INTRODUCTION

1 A. Qualifications

2

3 Q. Please state your name, address and position with Southern Natural Gas Company
4 (Southern).

5

6 A. My name is Glenn A. Sheffield. I am the Director – Rates of Southern, P.O. Box 2563,
7 Birmingham, Alabama 35202.

8

9 Q. Please describe briefly your education and business background.

10

11 A. I graduated from Auburn University in December 1977 with a Bachelor's degree in
Electrical Engineering. Upon graduation, I was commissioned as an officer in the United

(GAS-I)
Page 2 of 40

1 States Navy. In January 1982, I began my employment with Southern as an Engineer in
2 the Engineering Department and, in October 1987, I was assigned to the Rates
3 Department. In March 1988, I received a Masters of Business Administration degree
4 from the University of Alabama at Birmingham.

5

6 Q. Please describe your present duties with Southern.

7

8 A. Since joining the Rates Department, I have been given assignments of increasing
9 responsibility leading to my current position, where I am responsible for the analysis and
10 development of the jurisdictional rates for Southern and its subsidiaries.

11

12 Q. Have you previously testified or presented testimony before the Federal Energy
13 Regulatory Commission?

14

15 A. Yes. I have presented testimony on behalf of Southern in several of Southern's recent
16 rate proceedings including its most recent rate proceeding in Docket No. RP99-496. I
17 have also presented testimony in Southern's Order No. 636 restructuring proceeding in
18 Docket No. RS92-10 and in some of the recent rate proceedings of Southern's
19 subsidiaries.

(GAS-1)
Page 3 of 40

1 **B. Purpose of Testimony**

2
3 Q. What is the purpose of your direct testimony in this proceeding?

4
5 A. I will present Southern's proposed cost classification, cost allocation and rate design for
6 all of its jurisdictional services. I will also testify concerning the business risks faced by
7 Southern that form the basis for Southern's proposed rate of return on equity, and I will
8 explain generally the basis for discounts to its services.

9
10 **C. Exhibits**

11
12 Q. Are you sponsoring any exhibits?

13
14 A. Yes. Exhibit No. SNG-___(GAS-2) contains a map of Southern's system and Exhibit
15 No. SNG-___(GAS-3) shows contract terms.

II.

SOUTHERN'S PIPELINE SYSTEM

A. Configuration

Q. Please briefly describe Southern's pipeline system.

A. Southern is a regional pipeline serving the southeastern United States. Southern's firm transportation capacity is approximately 3.4 Bcf/day, with such capacity being generally telescoped from the primary producing areas in the Gulf of Mexico and Louisiana to its major markets in the states of Alabama, Georgia, and South Carolina. There are two underground storage facilities directly connected to Southern, one of which, Muldon, is wholly owned by Southern. The other, Bear Creek, is 50% owned by Southern. These storage fields are located in the states of Mississippi and Louisiana, respectively. Southern's wholly owned subsidiary Southern LNG Inc. (SLNG) operates an LNG import terminal connected to the eastern end of Southern's system. As shown in Exhibit No. SNG-___(GAS-2), Southern's pipeline system is configured in a distribution-like manner, with many of Southern's customers receiving service from Southern through numerous delivery points. For example, Southern provides deliveries to its two largest customers located in Alabama and Georgia at 157 active delivery points throughout these states.

(GAS-1)
Page 5 of 40

1 B. Services

2

3 Q. Please briefly describe the services which Southern provides.

4

5 A. Southern provides both firm and interruptible transportation service to 256 customers on
6 its system. Southern also provides both firm and interruptible storage service to
7 141 customers utilizing the Muldon and Bear Creek facilities I mentioned previously.
8 Southern provides its storage services from Muldon and Bear Creek on an aggregated
9 basis. Southern's tariff allows customers holding both firm transportation and firm
10 storage to receive service as firm no-notice service. Southern has provided these services
11 since its unbundling under Order No. 636.

12

13 Q. Has Southern established any new services since its last general rate case?

14

15 A. Yes. On April 1, 2001, Southern began providing a Park and Loan (PAL) service
16 pursuant to the Commission's order dated February 28, 2001 in Docket No. RP01-242.
17 This service, which is only available on an interruptible basis, allows customers to park
18 gas on Southern's system for a period of time or receive a loan of gas for a period of
19 time. Southern provides this service using its operationally available assets, principally
20 line pack and retained storage, or through offsetting parks and loans. I will discuss the
21 rates related to the PAL service later in my testimony.

(GAS-1)
Page 6 of 40

1 Q. What is the basis for the cost classification, cost allocation and rate design underlying
2 Southern's currently effective rates?

3

4 A. With the exception of the PAL service established since Southern's last rate case,
5 Southern's currently effective base tariff rates are those established by the Commission in
6 its May 31, 2000 order which approved a settlement of Southern's last general rate case
7 proceeding in Docket No. RP99-496 ("Stipulation and Agreement").

8

9 C. Current Rates

10

11 Q. Did the Commission make a merits determination in Docket No. RP99-496 concerning
12 the appropriate cost classification, allocation and rate design for Southern?

13

14 A. No. Because the Stipulation and Agreement was uncontested, the Commission approved
15 the Stipulation and Agreement on the basis that it was fair and reasonable and in the
16 public interest.

17

18 Q. Did the Commission make a merits determination on cost classification, allocation and
19 rate design in Southern's general rate case prior to Docket No. RP99-496?

20

(GAS-1)
Page 7 of 40

1 A. Yes. In orders issued on September 29, 1995 and April 11, 1996, the Commission
2 accepted a settlement filed on March 15, 1995 which resolved numerous Southern rate
3 and certificate proceedings, including Southern's Order No. 636 restructuring proceeding
4 and Southern's most recent general rate proceeding, prior to Docket No. RP99-496, in
5 Docket No. RP93-15. Because such settlement was partially contested, the
6 Commission's orders resolved on the merits the numerous cost classification, allocation
7 and rate design issues raised by the contesting parties.

8
9 Q. Are you recommending any changes in the instant proceeding with respect to the cost
10 classification, allocation and rate design issues resolved by the Commission in its
11 September 25, 1995 and April 11, 1996 orders?

12
13 A. With the exception of the changes provided for in the provisions of the Stipulation and
14 Agreement and certain relatively minor changes which I will discuss later in my
15 testimony, I believe that the cost classification, allocation and rate design approved in the
16 September 29, 1995 and April 16, 1996 orders continue to be appropriate for Southern's
17 system.

18
19 Q. What changes in cost classification, allocation and rate design were provided for in the
20 Stipulation and Agreement?

21

(GAS-1)
Page 8 of 40

1 A. The most significant change is that, under the Stipulation and Agreement, South Georgia
2 Natural Gas Company (South Georgia) was merged into Southern. Prior to the
3 effectiveness of the Stipulation and Agreement, South Georgia was a wholly owned
4 subsidiary corporation of Southern. South Georgia's costs and revenues were separate
5 from Southern's, and its rates were determined by the Commission in rate proceedings
6 separate from Southern's rate proceedings. Upon the effectiveness of the Stipulation and
7 Agreement, South Georgia ceased to be a separate corporate entity pursuant to a
8 certificate application in Docket No. CP00-117 in which Southern was authorized to
9 acquire and operate all of South Georgia's assets and to provide service to all of South
10 Georgia's customers. Under the Stipulation and Agreement, separate rates were
11 established for services on the facilities that were formerly South Georgia through an
12 allocation of the combined costs of service of those facilities and Southern's existing
13 facilities.

14
15 Q. Do you propose to continue the same methodology established in the Stipulation and
16 Agreement for determining the rates for services on the formerly South Georgia
17 facilities?

18
19 A. Yes.

20

(GAS-1)
Page 9 of 40

1 Q. What other cost classification, allocation and rate design changes were reflected in the
2 Stipulation and Agreement?

3

4 A. Under the Stipulation and Agreement, a Part 157 firm transportation service known as the
5 ANR Storage Transportation Service (STS) was to be converted to Part 284 service under
6 Southern's existing FT rate schedule. The Stipulation and Agreement further provided
7 that the converted service would be at the same contract quantity as under the STS
8 service and be for a six-month period from October through March of each year at the
9 maximum rates under Southern's FT rate schedule. As of October 1, 2004, all such
10 conversions will have occurred. In accordance with the Stipulation and Agreement, on
11 August 23, 2004, Southern made a compliance filing to reflect a rate reduction to all of its
12 base reservation rates under Rate Schedule FT and its base rates under Rate Schedule IT
13 to be effective October 1, 2004.

14

15 Q. Are you proposing to continue treating the converted STS service as Part 284 service in
16 the instant proceeding?

17

18 A. Yes. Pursuant to the Stipulation and Agreement and Southern's application to abandon
19 the Part 157 service and convert it to Part 284 service in Docket No. CP00-170, the
20 converted STS service is to be treated no differently than other Part 284 FT service on
21 Southern's system.

1 III.

2 COST CLASSIFICATION

3
4 Q. Have you continued to use the straight fixed variable (SFV) methodology in this
5 proceeding?

6 A. Yes. I have continued to use the SFV methodology for cost classification, cost allocation
7 and rate design in this proceeding. SFV continues to be the methodology preferred by the
8 Commission.

9
10 IV.

11 COST ALLOCATION

12
13 A. Reservation Costs

14
15 Q. Turning first to cost allocation, how do you propose to allocate reservation costs?

16
17 A. I propose to continue to utilize annual reservation contract quantities for firm services
18 and imputed reservation contract quantities for interruptible services and volumetric
19 small shipper services, to allocate reservation costs among zones. In the Commission's
20 September 29, 1995 order, the Commission determined that this was the appropriate
21 methodology for Southern's system.

(GAS-1)
Page 11 of 40

1 Q. Does your allocation of costs to zones take into account the distance which gas travels?

2

3 A. Yes. I have continued to utilize mileage-based zones and rates for Southern's system
4 under the same structure approved by the Commission in its September 29, 1995 and
5 April 11, 1996 orders. Under this structure, costs which are deemed to be mileage-based
6 are allocated to zones based on average miles of haul for each zone.

7

8 Q. What components of Southern's cost of service are not mileage-based?

9

10 A. Consistent with the methodology underlying Southern's current rates, administrative and
11 general costs, customer services and informational costs, supervision and engineering
12 costs (Account No. 850), system control and load dispatching costs (Account No. 851),
13 the cost of service attributable to Southern's measurement stations and the costs of
14 storage allocated to system usage are not mileage-based.

15

16 Q. Are there other costs which you recommend be classified as non-mileaged?

17

18 A. I have also reflected the cost of service of Southern's customer nominations and billing
19 computer system, commonly known as SoNet Premier, as non-mileaged. This system is
20 utilized on a transactional basis and the transaction costs do not vary based on mileage of
21 gas haul.

(GAS-1)
Page 12 of 40

1 Q. Have you continued to treat the costs of service attributable to Southern's unconnected
2 production area segments and its Wrens - Savannah line facilities as non-mileaged costs?

3

4 A. No. First, Southern's unconnected production area segments will be fully depreciated by
5 the end of the test period, hence there is no need to continue to segregate these facilities
6 from Southern's other transmission plant. Second, the rationale for treating the costs
7 attributable to Southern's Wrens-Savannah line facilities as non-mileaged cost has been
8 superseded by the reactivation of SLNG's LNG terminal.

9

10 Q. Please explain why the LNG terminal reactivation should impact the allocation of these
11 costs.

12

13 A. In the Commission's April 6, 1988 order in Docket No. RP83-58, the Commission found
14 that it was appropriate to allocate the costs of the Wrens-Savannah facilities on a non-
15 mileage basis because the LNG terminal connected to the end of the line had ceased to
16 provide terminaling service. The circumstances have changed. The Wrens-Savannah
17 line is now being actively used to transport gas from the reactivated terminal. Thus, the
18 facts that the Commission relied upon as a basis for previously requiring the allocation of
19 costs on a non-mileage basis no longer exist, and it now is appropriate to allocate the cost
20 of these facilities on a mileage basis consistent with the allocation of the costs of the

1 remainder of Southern's transmission facilities, other than Southern's measurement
2 stations.

3
4 **B. Storage Costs**

5
6 Q. Do you propose to allocate any of Southern's storage function costs to its pipeline
7 transportation services?

8
9 A. Yes. In Southern's Order No. 636 restructuring proceeding in Docket No. RS92-10,
10 Southern was authorized to retain a small amount of its storage for system operations and
11 load management. This retained storage provides a benefit to all pipeline transportation
12 services by facilitating the balancing of receipt and delivery volumes. Further, by
13 utilizing this retained storage, Southern has been able to avoid the construction of
14 additional transmission facilities. If additional transmission facilities had been
15 constructed, the cost of these facilities would have been allocated to Southern's pipeline
16 transportation services. Therefore, it is appropriate to allocate the costs of the retained
17 storage to transportation services because the storage capacity is being used to serve the
18 transportation function in lieu of pipeline facilities that otherwise would have to be
19 constructed.

20

(GAS-1)
Page 14 of 40

Q. Please describe the methodology you are proposing to use to allocate the costs of Southern's retained storage.

A. I have continued to use the same methodology approved by the Commission in its September 29, 1995 order. Under this methodology, retained storage capacity, deliverability and injection levels are used as allocation determinants to allocate total storage costs between Southern's pipeline transportation services and its unbundled storage services. Southern's allocation factors are comparable in design to those the Commission prefers under the method originally adopted in *Equitable Gas Company (Equitable)*, 36 FERC ¶ 61,147 (1986). These allocation factors result in the allocation of approximately 18 percent of Southern's total storage costs to Southern's pipeline transportation services. The following table sets forth the allocation of storage costs to pipeline transportation services.

	<u>Total Cost</u>	<u>Pipeline Trans. Allocation Factors</u>	<u>Cost Allocated Pipeline Trans.</u>
Deliverability	\$22.4 Mil	12.4%	\$2.8 Mil
Capacity	22.4	13.3%	3.0
Working Storage	2.4	100.0%	2.4
Injection/Withdrawal	<u>1.1</u>	<u>34.7%</u>	<u>0.4</u>
Total Storage	\$48.4 Mil	17.7%	\$8.6 Mil

(GAS-1)
Page 15 of 40

1 Q. Have these allocation percentages changed from those underlying Southern's current
2 rates?

3

4 A. Yes, but only to the limited extent necessary to reflect actual storage activities. While
5 Southern is proposing to continue the same levels of retained storage in this proceeding
6 as the levels previously approved by the Commission, and the total storage capabilities
7 have not changed, the allocation percentages for Deliverability, Capacity and
8 Injection/Withdrawal have been adjusted to reflect the imputed units for the base period
9 actual Interruptible Storage (ISS Rate Schedule) volumes and the base period actual
10 injection and withdrawal volumes.

11

12 Q. Why does Southern propose to continue the same levels of retained storage?

13

14 A. Southern continues to need these levels of retained storage in order to effectively manage
15 its system. It is not uncommon for Southern's daily throughput to fluctuate by over
16 1,000,000 Dth from one day to the next as cold fronts move through the Southeast, and to
17 fluctuate by over 300,000 Dth from one day to the next in hot summer weather. The
18 daily swings in throughput are at least as great today as they were when Southern
19 restructured its services under Order No. 636. Thus, I believe it is reasonable for
20 Southern to maintain the current levels of retained storage.

21

(GAS-1)
Page 16 of 40

1 Q. Why are you proposing to allocate 100% of the cost of working storage in Southern's
2 retained storage to the pipeline transportation services?

3
4 A. This element of Southern's storage cost is attributable to the return and income taxes on
5 the working storage necessary to perform the system operations and load management
6 functions of its retained storage. The working storage balance underlying this cost does
7 not include any storage gas volumes owned by Southern's unbundled storage service
8 customers, and therefore, should be allocated in its entirety to Southern's pipeline
9 transportation services. This allocation methodology is the same as that accepted by the
10 Commission in its September 29, 1995 and April 11, 1996 orders.

11
12 Q. Does your proposed methodology for allocating storage costs allocate any additional cost
13 to the transportation component of each unit of Southern's no-notice service provided
14 under Rate Schedule FTNN, as compared to what is allocated to each unit of regular firm
15 transportation service provided under Rate Schedule FT?

16
17 A. No, it does not. As the Commission found in its September 29, 1995 and April 11, 1996
18 orders, the fact that Southern's overall rate for no-notice service includes both the cost of
19 firm transportation and the cost of firm unbundled storage under Rate Schedule CSS
20 dictates that the same per unit allocation will be commensurate with the nature of the
21 services. Accordingly, it would be inappropriate to allocate a larger proportion of

(GAS-1)
Page 17 of 40

1 Southern's retained storage cost to no-notice transportation than is allocated to regular
2 firm transportation. Because the no-notice rates filed in this case continue to include both
3 firm transportation and storage, I believe that the Commission's rationale underlying this
4 conclusion continues to be valid today. Therefore, I do not recommend any change in the
5 Commission-approved methodology.
6

7 C. PAL Costs
8

9 Q. Earlier in your testimony you mentioned that since your last general rate case, Southern
10 had established a new PAL service. Have you allocated costs to the PAL service in
11 developing your proposed rates in this proceeding?
12

13 A. Rather than allocating costs to this service, I believe that, given the significant
14 discounting that occurs and the significant volatility in the rates that Southern is able to
15 collect, a more equitable method is to credit the test period revenues received from the
16 PAL service to Southern's transmission function cost of service. While I will discuss the
17 basis for Southern's discounts later in my testimony, if Southern were to allocate cost to
18 the service and then design rates for the service, based on such allocation the resulting
19 rates would produce significantly lower revenues than Southern's test period projected
20 revenues. Since Southern uses its operationally available assets to provide the PAL
21 service, to the extent that revenues from the PAL service are lower, Southern's rates for

(GAS-1)
Page 18 of 40

1 its other transportation services would have to be higher. In light of the historical
2 patterns in the revenues associated with the PAL service, I do not believe that a separate
3 allocation methodology is appropriate.

4
5 Q. Does significant discounting of the PAL services suggest that the PAL rates should be
6 lower?

7
8 A. No. The nature of the PAL service is unique. Since this service allows customers to park
9 or loan gas over time, the rate received is driven by differences in gas prices during the
10 period over which the gas will be parked or loaned. For example, if Henry Hub prices
11 are \$5.00/Dth in one month and the NYMEX price for gas six months into the future is
12 \$6.00/Dth, a customer might be willing to pay up to \$1.00/Dth to park gas for that six
13 month period. To the extent that Southern's PAL rates are set at a significantly lower
14 level than the current rates, there would be numerous instances in which Southern would
15 be unable to charge a rate that reflects the actual value of the service provided.

16
17 **D. Discounts**

18
19 Q. Have you reflected the impact of pipeline transportation discounts in your allocation of
20 costs to the rate zones?

21

(GAS-1)
Page 19 of 40

1 A. Yes. For each component utilized in the allocation process, I have adjusted the units used
2 to allocate costs to each zone to reflect the impact of discounted transportation services. I
3 have performed this adjustment by weighting the allocation determinants for each zone to
4 reflect the actual rate to be received. Furthermore, in designing rates, I have also used the
5 discounted volumes and the base tariff rate to be received relative to the maximum base
6 tariff rate to arrive at the rate design billing determinants in each zone.

7
8 Q. What level of discounts is Southern reflecting in this proceeding?

9
10 A. Southern's witness Lucas supports Southern's test period level of discounting and billing
11 determinants in his prepared direct testimony. Mr. Lucas also presents the computations
12 implementing my recommended cost allocation methodologies. Later in my testimony, I
13 will explain generally Southern's basis for discounts to its services.

14
15 V.

16 RATE DESIGN

17
18 A. FT Rates

19
20 Q. Turning to rate design, how did you design Southern's FT rates in this proceeding?

21

(GAS-1)
Page 20 of 40

1 A. Once costs were allocated to each zone, I designed rates for services under Southern's
2 firm transportation rate schedules by dividing the reservation and commodity cost levels
3 by the applicable reservation and commodity design units in each zone.
4

5 Q. How did you determine FT rates for Southern's small, G customers?
6

7 A. In determining the FT rates for the G customers, I designed volumetric rates for each
8 zone based on the same imputed load factor set forth in the Stipulation and Agreement of
9 Southern's last general rate case.
10

11 **B. IT Rates**
12

13 Q. How do you propose to design Southern's IT rates?
14

15 A. I have designed rates for IT service based on a 100% load factor derivative of the FT
16 rates. This is the same load factor IT rate design which the Commission found to be
17 appropriate for Southern in its September 29, 1995 and April 11, 1996 orders. 100% load
18 factor derivative IT rates continue to be the standard which the Commission has used for
19 pipelines in general since it issued Order No. 636.

1 C. Gathering Rates

2

3 Q. How do you propose to design gathering rates for Southern?

4

5 A. I am proposing to use the same methodology as that accepted by the Commission in
6 Southern's restructuring proceedings, as provided in the Stipulation and Agreement of
7 Southern's most recent rate proceeding, and as approved in the September 29, 1995 and
8 April 11, 1996 orders. I have derived Southern's proposed gathering rate of 4.7¢/Dth by
9 dividing the cost of service for Southern's production and gathering function of \$772,248
10 by the test period volumes which are projected to flow through these facilities of
11 16,595,422 Dth.

12

13 Q. Has Southern recently agreed to sell its remaining gathering facilities?

14

15 A. Yes. On June 2, 2004 Southern included in an application in Docket No. CP04-348 a
16 proposal to sell its remaining gathering facilities to an unaffiliated company. On
17 August 9, 2004 the Commission approved the application as proposed. Southern
18 anticipates closing on the sale and filing to terminate its gathering service prior to the
19 effectiveness of Southern's filed rates in the instant proceeding. In such event, the
20 determination of Southern's gathering rates in the instant proceeding will be rendered
21 moot, and no gathering rates will be placed into effect.

1 **D. Storage Rates**

2
3 Q. How were Southern's rates for its unbundled storage services determined?

4
5 A. Southern's unbundled storage services consist of a firm storage service under Rate
6 Schedule CSS and an interruptible storage service under Rate Schedule ISS. I have
7 designed rates for these services using the same methodology approved by the
8 Commission in its September 29, 1995 and April 11, 1996 orders, with only one
9 exception. When Southern established its unbundled storage services in its Order
10 No. 636 restructuring and rate case proceedings that were the subject of the
11 September 29, 1995 and April 11, 1996 orders, Southern had no historical experience on
12 which to base its ISS levels of service. Southern, therefore, agreed to and the
13 Commission approved 100% crediting of ISS revenues, less variable costs, to Southern's
14 CSS customers. Since Southern now has historical experience regarding its ISS service
15 levels, consistent with the methodology in the Stipulation and Agreement of Southern's
16 last general rate proceeding, I have determined Southern's storage rates based on its
17 actual base period volumes for this service.

18
19 Q. Please explain how you designed rates for Southern's CSS service.

20

1 A. As provided for in *Equitable*, the rate for services under the CSS rate schedule consists of
2 four parts: (1) a reservation rate based on contracted daily withdrawal deliverability
3 (Deliverability rate); (2) a reservation rate based on contracted working storage capacity
4 (Capacity rate); (3) a commodity rate based on actual injections (Injection rate); and (4) a
5 commodity rate based on actual withdrawals (Withdrawal rate). Rates for Southern's
6 CSS service were then derived by dividing the component costs which have been
7 allocated to contract storage for deliverability, capacity, injection and withdrawal by the
8 billing determinants for each component including imputed billing determinants for ISS
9 service. The costs allocated to injections and withdrawals as well as the injection and
10 withdrawal billing units have been combined, and therefore the rates for injection and
11 withdrawal are the same.

12

13 Q. How did you design CSS rates for the customers electing the FT small shipper service?

14

15 A. Consistent with the methodology approved by the Commission in its September 29, 1995
16 and April 11, 1996 orders and in the Stipulation and Agreement, I have designed the CSS
17 deliverability rate for these customers based on deliverability billing units designed at a
18 37.5% load factor. The capacity and injection/withdrawal rates for these customers are
19 the same as for the large customers.

20

21 Q. Please describe how Southern has derived its proposed ISS rates.

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1 A. Consistent with the methodology underlying the rates in Southern's Stipulation and
2 Agreement, I have designed rates for ISS service based on a 100% load factor derivative
3 of Southern's firm four-part CSS rates.
4

5 E. Zone Matrix Rates
6

7 Q. Does Southern propose to continue the zone matrix methodology for computing its
8 transportation rates that was approved by the Commission in its September 29, 1995 and
9 April 11, 1996 orders?
10

11 A. Yes. This is also the same as the methodology underlying the Stipulation and
12 Agreement.
13

14 Q. Please explain Southern's zone matrix methodology.
15

16 A. Under this methodology, I have designed FT reservation rates based on the actual zone of
17 delivery. I have designed IT and FT commodity rates using a zone matrix methodology
18 whereby the inter-zone and intra-zone rates are computed by backing out the upstream
19 mileage based cost.
20

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1 Q. Have circumstances on Southern's system which would support the current zone rate
2 structure changed significantly since its last rate proceeding?

3
4 A. No. Southern's system continues to operate as an integrated system on which gas still
5 generally flows east from production areas offshore and in Louisiana and Mississippi to
6 Southern's major markets in Alabama, Georgia and South Carolina. The volumes of gas
7 received in Southern's market-area zones continue to remain relatively small in
8 proportion to the overall production area volumes.

9
10 F. PAL Rates

11
12 Q. How do you propose to design rates for Southern's PAL service?

13
14 A. Southern's PAL rates have been designed using the same methodology that was approved
15 by the Commission in its orders accepting the tariff sheets implementing this service.
16 This methodology reflects a two-tiered rate structure with a first day rate design based on
17 Southern's total transmission non-mileaged cost of service and a subsequent day rate
18 design based on the storage component of the transmission non-mileaged cost of service.
19 The first day rate is applied on the day that gas is initially parked or loaned, and the
20 subsequent day rate is applied to a shipper's balance under the PAL service on all days
21 excluding the initial day that gas is parked or loaned.

1 VI.

2 OTHER SERVICES

3
4 A. Shell Service

5
6 Q. What methodology are you proposing to use to allocate costs and determine the charges
7 for the service certificated in Docket No. CP95-500?

8
9 A. The service certificated in Docket No. CP95-500 is a Part 284 service provided under
10 Southern's FT Rate Schedule. Consistent with the methodology underlying the
11 Stipulation and Agreement, the reservation rate charged is based on the cost of service of
12 the specific facilities constructed to provide the service. The annual reservation rate
13 revenues resulting from the service are then credited to Southern's transmission function
14 cost of service before the cost allocation process begins.

15
16 Q. How were the rates designed for this service?

17
18 A. As discussed in detail in the certificate application and in the Commission's orders
19 approving Southern's proposal, the service certificated in Docket No. CP95-500 provides
20 certain firm production-area transportation (for Shell Offshore Inc.) of up to
21 140,000 Mcf/D, over a 10-year term, which commenced in 1996. The firm reservation

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1 charge approved by the Commission was to be based on the 10-year average incremental
2 cost of service of the facilities as set forth in the certificate application, adjusted only to
3 reflect the actual capital cost of the facilities and the actual platform space lease expense.
4 The resulting annual reservation rate revenue is \$2,298,475, which I have reflected as a
5 credit to Southern's transmission cost of service.

6
7 **B. At-Risk Services**

8
9 Q. Did Southern operate any facilities or provide any services that are subject to a
10 Commission at-risk condition during the base period in this proceeding?

11
12 A. No. Furthermore, none of the projected test period plant additions reflected in
13 Mr. Henderson's testimony are subject to an at-risk condition.

14
15 **C. Expansion Services**

16
17 Q. Has Southern completed and placed in-service any expansion projects since its last
18 general rate case?

19
20 A. Yes. Southern has completed and placed in-service four expansion projects since its last
21 general rate case. In 2001, Southern placed in-service an expansion of its South Georgia

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1 facilities certificated in Docket No. CP01-35. In 2002, Southern placed in-service the
2 first phase of an expansion of its South mainline system certificated in Docket
3 No. CP00-233. In 2003, Southern placed in-service the last phase of the Docket
4 No. CP00-233 facilities, an expansion of its North mainline system certificated in Docket
5 No. CP01-161, and the first two phases of a second expansion of its South mainline
6 certificated in Docket No. CP02-1. In August 2004, Southern placed in-service the final
7 phase of the facilities certificated in Docket No. CP02-1.

8
9 Q. Did the Commission make a predetermination of the rate treatment for these projects in
10 its orders issuing certificates for each of these projects?

11
12 A. Yes. In each of the orders issuing certificates the Commission determined that there
13 would be a presumption that the costs and revenues of these expansions would be treated
14 on a rolled-in basis in Southern's next general rate proceeding.

15
16 Q. Do Southern's filed rates in the instant proceeding reflect the Commission's rolled-in
17 rates presumptions for these projects.

18
19 A. Yes.

20

21

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VII.

DISCOUNTING

A. Background

Q. Earlier in your testimony you mentioned that Southern's proposed cost allocation and rate design reflect some discounting of its services. Please describe why it is necessary for Southern to make discounts.

A. Southern awards discounts when in its reasonable judgment it is likely that Southern would lose business without a discount, due to competitive alternatives.

Q. What competitive alternatives do Southern's customers have?

A. The competitive alternatives can be classified into two general categories: gas-on-gas competition and alternative fuel competition. With respect to gas-on-gas competition, many of Southern's customers, including its four largest customers, have connections that enable them to take gas from other major interstate pipelines. These four largest customers also have firm contracts with other interstate pipeline suppliers. As discussed later in my testimony, Southern faces significant competitive pressure from these pipelines both in contracting for new loads as well as in renewing existing contracts.

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1 Since these pipelines already have facilities in Southern's primary market area, it is quite
2 feasible that they could expand their facilities to provide additional service to Southern's
3 customers. In fact, as I will also discuss later, Southern's primary market area competitor
4 already has indicated a desire to attempt to cut into Southern's market share by
5 constructing major expansions in Southern's primary market area. With respect to
6 alternate fuel competition, a number of Southern's industrial customers have the ability to
7 burn alternative fuels, which, in today's environment of high gas prices, makes this
8 competitive pressure even more severe.

9
10 **B. PAL Discounts**

11
12 Q. Does Southern make discounts for reasons other than these two general categories?

13
14 A. There are two exceptions to these two general categories. As I mentioned earlier in my
15 testimony, Southern makes discounts for its PAL service based on basis differentials over
16 time. With respect to PAL service, the price that customers are willing to pay for the
17 service is based on the difference in gas prices on the day(s) that gas is delivered into
18 Southern's system (parked) or borrowed from the system (loaned) and the day(s) on
19 which the transaction is reversed by the park being returned to the shipper or the loan
20 being paid back to Southern.

21

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1 Q. If Southern were to refuse to grant PAL discounts what would be the result?

2
3 A. In many instances the transaction would simply not happen. A customer attempting to
4 use PAL service as a hedging tool could choose to implement an alternative hedging tool
5 or choose to operate with more gas price risk rather than pay for a higher rate PAL
6 transaction. In other instances, another pipeline or supplier may provide the service at a
7 price that clears the market.

8
9 C. Exxon Discounts

10
11 Q. What is the other type of discount you referred to?

12
13 A. During the base period, Southern continued to provide a discount to Exxon Corporation
14 (Exxon). Southern agreed to provide this transportation discount to Exxon as part of the
15 settlement of gas supply realignment issues. Under the settlement, Southern agreed to
16 transport for Exxon up to 50 MMcf per day of gas through the offsystem Matagorda
17 Offshore Pipeline System (MOPS) pipeline and two laterals located offshore Texas to
18 points of interconnection in Refugio County, Texas. The discounted rate for the
19 transportation service through the MOPS pipeline is 12¢ per MMBtu, while the
20 discounted rate through the laterals is 1¢ per MMBtu. The term of the discount runs
21 through August 2, 2007. In accordance with Article VII, Paragraph 6 of Southern's

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1 March 15, 1995 Stipulation and Agreement in Docket Nos. RP89-224 *et al.*, the
2 recognition of such discounts is precluded from challenge for purposes of designing
3 Southern's rates in rate proceedings.
4

5 **D. Affiliate Discounts**
6

7 Q. Were any of Southern's base period discounts to affiliates?
8

9 A. No.
10

11 **E. SCANA Discounts**
12

13 Q. Have any of Southern's base period discounts occurred in the context of negotiated rate
14 transactions?
15

16 A. With one possible exception, no. In the Commission's September 20, 2002 order in
17 Docket Nos. CP02-1-000 and CP02-1-001, the Commission found that the service
18 agreement between Southern and SCANA Resources, Inc. (SCANA) constituted a
19 negotiated rate agreement.
20

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1 Q. Why did the Commission determine that this agreement constituted a negotiated rate
2 agreement?

3

4 A. Although Southern had filed the agreement as a discounted rate agreement which under
5 certain circumstances could result in the rate to be charged being less than Southern's
6 maximum tariff rate, apparently the Commission believed that since the rate to be
7 charged SCANA potentially could be based on a formula, it constituted a negotiated rate.

8

9 Q. Please describe the relevant provisions of the SCANA agreement.

10

11 A. The agreement provides that the reservation charge shall be the lower of Southern's
12 maximum zone 3 reservation charge under its existing FT rate schedule or \$11.50/Dth.
13 After five years, the \$11.50/Dth rate cap was to be escalated at 40% of the Gross
14 Domestic Product Deflator.

15

16 Q. Is the Commission's September 20 order consistent with the Commission's current policy
17 differentiating discounted rate transactions from negotiated rate transactions?

18

19 A. No. I believe that the Commission's policy distinguishing between discounted and
20 negotiated rates has changed. The September 20 order was issued prior to the
21 Commission's December 18, 2003 Order on Remand in *Northern Natural Gas Company*,

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1 Docket No. RP00-152-002. In *Northern*, the Commission found that pipelines may enter
2 into discounted rate agreements that use formulas which may produce fluctuating
3 transportation rates, so long as the rates remain within a pipeline's maximum and
4 minimum tariff rates. See *Northern Natural Gas Company*, 105 FERC ¶ 61,299 (2003).

5
6 Q. Should Southern's agreement with SCANA qualify as a discounted rate under the
7 Commission's current policy?

8
9 A. Yes. Since under the agreement the charge is "the lower of" the tariff rate or \$11.50/Dth,
10 the rate should be considered a discounted rate rather than a negotiated rate.

11
12 **VIII.**

13 **BUSINESS RISK**

14
15 **A. - Supply Area**

16
17 Q. Turning to the issue of Southern's business risk, please describe the competitive
18 landscape in the geographic area in which Southern operates.

19
20 A. In Southern's production area zone and Zone 1, which are located in the Gulf of Mexico,
21 Louisiana and Mississippi, the markets are served by numerous interstate and intrastate

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1 pipelines as well as non-jurisdictional gathering companies. In these areas discounting is
2 required much of the time because of the accessibility to the diverse competitive
3 alternatives.

4
5 **B. Market Area**

6
7 Q. What is the competitive landscape in Southern's primary market area?

8
9 A. As I mentioned earlier in my testimony, in Southern's primary market area of Alabama,
10 Georgia and South Carolina, which account for approximately 92% of Southern's
11 transportation and storage revenues, Southern's system is configured as a distribution-
12 like system with numerous delivery points to many of our customers. This contrasts with
13 Southern's primary competitor, Transcontinental Gas Pipeline Corporation (Transco),
14 which is the classically configured long-line transmission system from the Gulf of
15 Mexico to the Northeast United States, with larger diameter pipeline. The result of this
16 difference in configuration is that Southern has higher per-unit fixed cost than Transco
17 and thus higher rates than Transco.

18
19 Q. Please quantify the difference in Southern's and Transco's transportation rates.

20

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A. With respect to Transco's system rates, the following chart compares the current reservation rates for Transco from the interconnection where gas is received from its Mobile Bay line in Transco's Zone 4 to Southern's current reservation rates:

FT Reservation Charges

\$/Dth per Month

	<u>Alabama</u>	<u>Georgia</u>	<u>South Carolina</u>
Transco	\$5.19	\$ 5.19	\$ 8.14
Southern	\$8.10	\$10.79	\$10.79

Q. Has Transco sought to expand its capacity to serve additional load in Southern's primary market area?

A. Yes. Since Southern's last rate case, Transco has completed three major expansion projects which serve loads in Alabama, Georgia and South Carolina, including service to Southern's largest customer, Atlanta Gas Light Company.

Q. What rates does Transco charge for service in these expansion projects?

A. All of the service in these expansions is provided at negotiated rates which tend to vary by the location of the firm receipt and delivery points as well as the contract term. For example, for service from receipt points in Transco's Zone 4 to delivery points along

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1 Transco's mainline in Georgia, the reservation rates have ranged from \$6.08/Dth to
2 \$8.21/Dth, all below Southern's currently effective rate for service into Georgia. The
3 largest load under these expansions, a 140,000 Dth/day service to a Southern Company
4 electric generating plant in Georgia, is at a negotiated reservation rate of \$7.00 and no
5 base commodity charge.

6
7 Q. Does Southern face competition from other pipelines in its primary market area?

8
9 A. Yes. Southern also faces competition from East Tennessee Natural Gas Company ("East
10 Tennessee"), which has an interconnection with Atlanta Gas Light and from Gulf South
11 Pipeline Company. East Tennessee markets its service aggressively in Georgia and
12 currently has significant firm capacity available as a result of the underutilization of its
13 "Patriot" expansion which went into service in 2003 pursuant to the certificate order
14 dated November 20, 2002 in Docket No. CP01-415. *See East Tennessee Natural Gas*
15 *Company*, 101 FERC ¶ 61,188 (2002), *order on reh'g*, 102 FERC ¶ 61,225 (2003).
16

17 C. Capacity Turnback
18

19 Q. Does competition from Transco and other pipelines place Southern at a significant risk of
20 turnback when its contracts expire?
21

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1 A. Yes. As shown on Exhibit No. SNG-___ (GAS-3), approximately 31% of Southern's
2 firm transportation contracts, measured by contract demand, will come up for renewal
3 before the end of 2005. Moreover, the weighted average remaining term of Southern's
4 firm transportation contracts as a whole as of the end of the test period in this proceeding
5 is only approximately four and one-half years.

6

7 Q. How does the four and one-half years average remaining life for Southern's contracts
8 compare to the remaining economic life of Southern's facilities based on its proposed
9 depreciation rates in this proceeding.

10

11 A. As Mr. Henderson's testimony indicates, Southern's net plant is approximately
12 \$1.6 billion. At an annual depreciation and amortization expense of approximately
13 \$59 million, which Southern proposes in this proceeding, Southern's pipeline system will
14 have an average depreciable life of approximately 27 years, or six times the average
15 remaining life of its contracts.

16

17 Q. Has Southern attempted to respond to the intense pipeline competition in its primary
18 market area?

19

20 A. Southern has responded to such competition from two principle perspectives. First,
21 Southern has aggressively moved to lower its cost since the Commission's restructuring

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1 of the pipeline industry under Order No. 636. For example, Southern has been able to
2 reduce the number of employees needed to run the pipeline from 1,154 in 1993 to 436 as
3 of the end of the base period in this proceeding - a reduction of 62%. Second, Southern
4 has aggressively pursued expansions of its system where the economics of the expansions
5 are such that the incremental revenues from the expansion will exceed the incremental
6 cost of the project, thereby spreading existing fixed cost over additional units of service
7 and thus reducing its rates to existing customers.

8
9 Q. Has Southern been successful in its expansion efforts?

10
11 A. Yes. As I discussed earlier in my testimony, Southern has constructed four expansions of
12 its system since its last rate case. These projects have expanded the capacity of
13 Southern's system by approximately 25% and, as the Commission found in its certificate
14 orders, rolling in the projects will provide both financial and operational benefits to
15 Southern's existing customers. On the other hand, while Southern has been successful in
16 capturing significant load growth in its primary market area, both Transco and East
17 Tennessee have aggressively priced their own expansions to capture some of the growth.
18 In some instances this has required Southern to discount its FT service associated with
19 the expansions in order to capture its share of the load growth in the Southeast.

20
21 Q. What other measures has Southern taken to respond to its competitive pressures?

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1 A. In an attempt to balance Southern's need for an adequate return to attract capital
2 investment while also recognizing the competitive market conditions, Southern has
3 selected a 13.5% rate of return on equity. This return on equity is below both the 14.29%
4 mean and 13.96% median returns on equity supported in the prepared direct testimony of
5 Southern's witness Williamson.

6

7 Q. What is your overall assessment of Southern's business risks?

8

9 A. Based on Southern's significant level of recontracting risk, particularly in the near term
10 and the intense level of competition in its primary market area, I conclude that Southern's
11 business risk is as least as great as the business risk of the average pipeline.

12

13 Q. Does this conclude your testimony?

14

15 A. Yes.

Exhibit No. SNG (GAS-2)

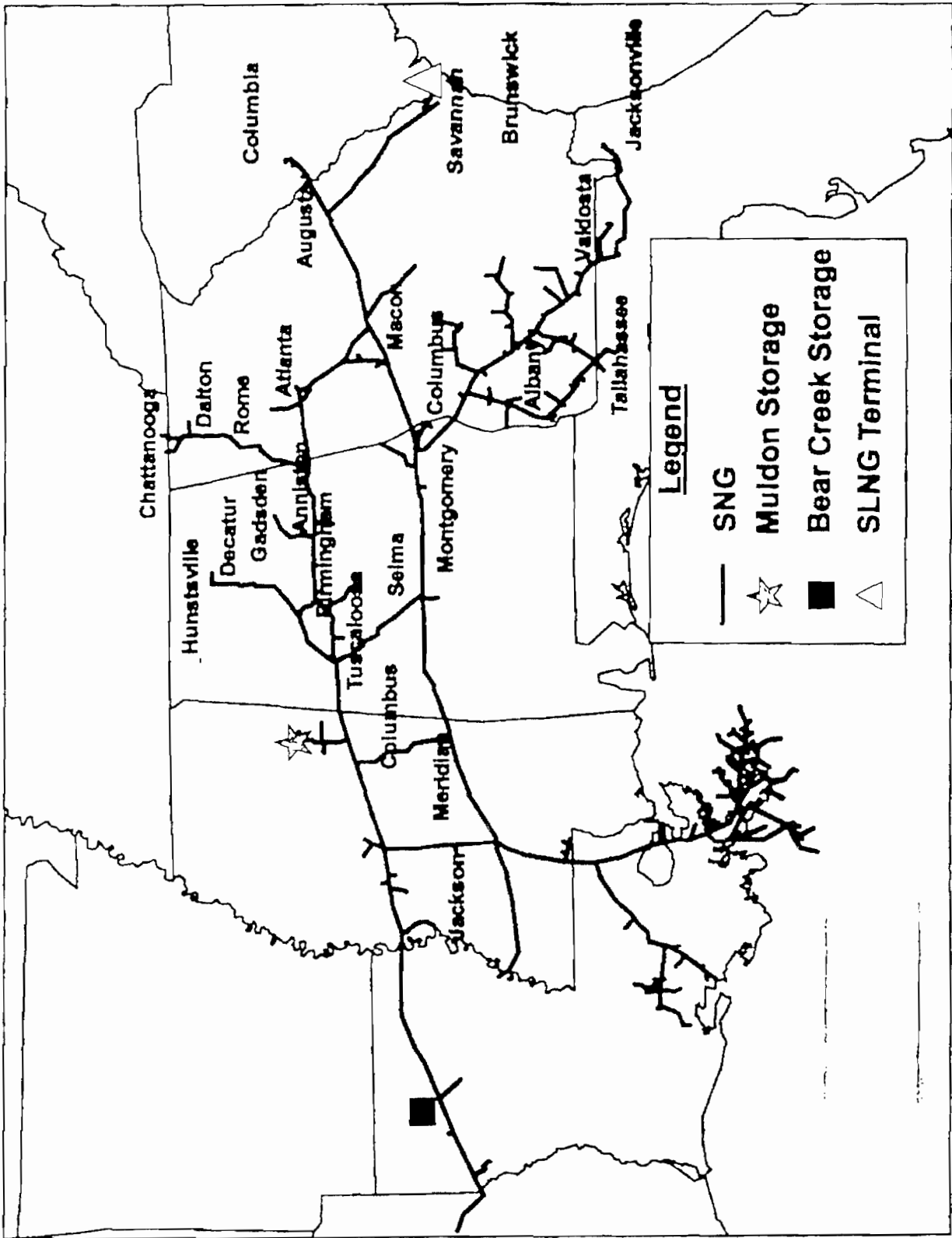
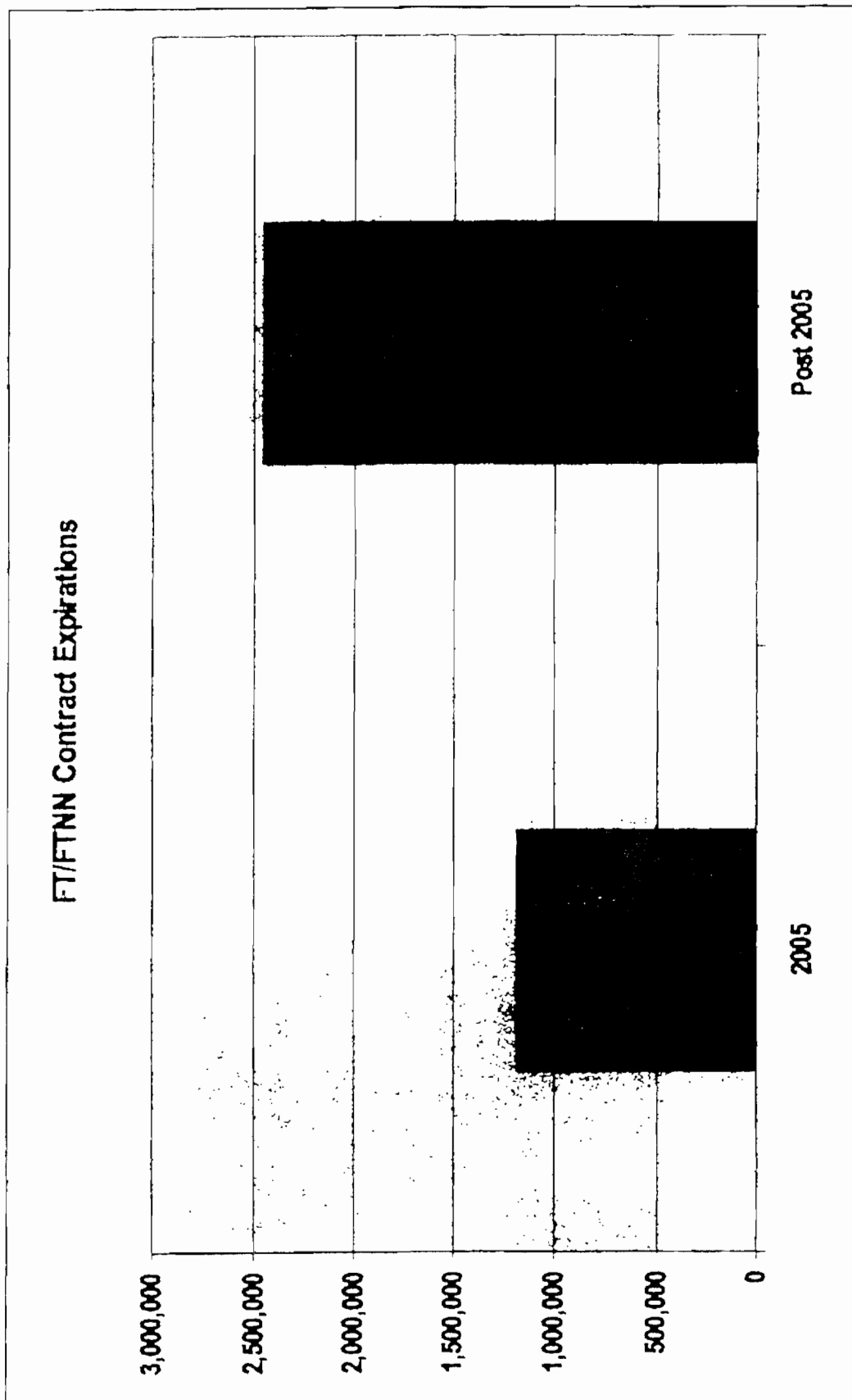


Exhibit No. SNG ____ (GAS-3)



UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southern Natural Gas Company

)
) Docket No. RP04-____-000
)

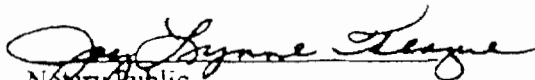
State of Alabama

County of Jefferson

Glenn A. Sheffield, being first duly sworn, on oath says that he is the Glenn A. Sheffield identified in the foregoing prepared direct testimony; that he caused to be prepared such testimony; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.


Glenn A. Sheffield
Director - Rates
Southern Natural Gas Company
P.O. Box 2563
Birmingham, Alabama 35202-2563
(205) 325-3813

Sworn to and subscribed before me this
20th of August, 2004.


Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF ALABAMA AT LARGE
MY COMMISSION EXPIRES: Dec 5, 2004
~~ISSUED BY THE NOTARY PUBLIC UNDERWRITERS~~

EXHIBIT

F

1. Southern's proposal to extend the notice period in the currently-effective section 39 of the GT&C from 90 days to 24 months for contract demand reductions pursuant to an order of a state regulatory commission ("PSC Out").
2. Southern's proposal to revise section 2.1(e) of the GT&C to provide that primary receipt points may be added to or deleted from Exhibit A to a service agreement provided that they are in the same zones for which the shipper has contracted for firm service, and to allow shippers to add or delete primary delivery points from Exhibit B to a service agreement only if the additional delivery points are in the same zone as the

shipper's current delivery points ("Amendment of Primary Receipt Points").

3. Southern's proposal to change its cash out price calculation to apply the high/low index price to the zero to two percent tolerance level ("Cash Out").
4. Southern's pro forma proposal to revise section 14.2 for the GT&C to apply the Storage Cost Reconciliation Mechanism to supply poolers ("SCRM").

II. PSC Out

At the technical conference, Southern presented its response to the general opposition to the 24 month notice requirement. Southern stated that the Commission does not require pipelines to offer PSC Outs and such provision was offered as part of Southern's settlement in Docket No. RP99-496, which expired in March 1, 2004. Southern added that it voluntarily continued the PSC Out by not removing the provision in the current proceeding. Southern also stated that the proposed 24 month notice requirement allows it to balance the goal of providing shippers flexibility with need to protect Southern and its customer base against revenue erosion. Southern suggested that LDCs could remarket surplus capacity through capacity release during the interim period to mitigate the impact. It added that the proposed 24 month notice requirement provides reasonable timeframe to remarket the turned back capacity through an expansion.

AGLC and CGC remain opposed to a 24-month notice requirement. Southern still has not offered any concrete evidence to support its claim that a 24-month notice requirement is necessary to mitigate the effects of the turned back capacity, and it has yet to "[e]xplain why the change is being proposed at this time."¹ Moreover, Southern admitted that no shipper has ever exercised the PSC Out. Therefore, Southern has not

¹ 18 C.F.R. § 154.204(c).

provided any support for the proposed revision in the manner required by the Commission's rules and regulations.

As discussed in AGLC and CGC's September 13, 2004 filing, extending the notice period to 24 months would fatally undermine the purpose of the contract demand option and upset the balance of risk that Southern negotiated with the shippers when it established the program as part of the settlement in Docket No. RP99-496. The purpose of the contract demand reduction option is to enable an LDC to respond to a final order by a state commission and reduce its transportation quantity in a timely fashion. AGLC and CGC submit that the current ninety-day notice period properly balances the risk of turned back capacity between shippers and the pipeline. A 24-month notice period, on the other hand, would shift virtually all of the risk to the shipper exercising the PSC Out option.

Additionally, despite the voluntary inclusion of the PSC Out in the Tariff by Southern, the provision should be consistent with other notice periods that the Commission has approved as part of contract demand reduction mechanisms on other pipelines. The proposed 24-month notice period would be a radical departure from the notice periods that the Commission has approved.² Southern has not presented any evidence that the proposed 24-month notice requirement is just and reasonable. Therefore, the Commission should reject this proposed revision as inconsistent with Commission precedent.

² See, e.g., *Columbia Gas Transmission Corp.*, 103 FERC ¶ 61,388, at P 9 (2003) (Commission accepts tariff sheets permitting insertion in service agreements of CD reduction rights to the extent a shipper is required to implement regulatory unbundling; reduction to take effect the later of the effective date of the regulatory unbundling or following sixty days written notice to Columbia); *Gulf South Pipeline Co., L.P.*, 101 FERC ¶ 61,019 at 61,058, at PP 10, 11 (2002) (Commission approves tariff sheets permitting reduction in "Winter Season Daily Contract Demand" under Rate Schedule NNS upon 60 days' notice following final order requiring NNS shipper to permit retail unbundling or implement open access transportation and upon a mutually agreed number of days, not to exceed 60, notice following final order that an NNS shipper has contracted for too much capacity on Gulf South).

III. Amendment of Primary Receipt Points

In its presentation, Southern stated that the proposed Amendment of Primary Receipt Points Tariff revision was not intended to limit the nomination of secondary receipt points. Rather, the revision attempts to clarify the contracting rules for amendment of firm receipt points, which is once a shipper has contracted for firm receipt point capacity, its ability to amend its contract should be within the contracted for zones. Such a rule is contrary to Commission policy and Southern's zone of delivery rate design.

Pursuant to Order 636-A, "a shipper gets flexibility in receipt and delivery points for the part of the system for which it pays a reservation charge."³ Under Southern's zone of delivery rate design, a shipper paying the Zone 3 delivered rate pays for capacity in Zones 1, 2 and 3 and may currently have its firm receipt points in Zone 1. Southern's proposal would prohibit shippers from amending their firm receipt points to zones other than those in its current contract although it may be paying for capacity in all zones. Shippers should be able to amend their receipt points to zones for which they are paying.⁴ Accordingly, the Commission should reject Southern's proposed Amendment of Primary Receipt Points revision.

IV. Cash Out

AGLC and CGC continue to support the Cash Out proposed Tariff revisions. As discussed in AGLC and CGC's September 13 filing, the companies have long been concerned that the current cash-out mechanism presented opportunities for gaming Southern's system by making the end of the month cash-out price too predictable. AGLC and CGC support the proposed Cash Out revisions because they will reduce arbitrage

³ Order 636-A, *FERC Stats. and Regs., Regulations Preambles 1991-1996* ¶30,950 (1992).

⁴ See *Great Lakes gas Transmission Limited Partnership*, 101 FERC ¶61,206, *clarifying* 100 FERC ¶61,083(2002) ("The Commission will require Great Lakes to permit shippers to permanently add, or change, primary points to those outside the transportation paths stated in their firm contracts, but within zones for which they are paying. This policy applies to segmented transactions as well.")

opportunities. Accordingly, AGLC and CGC urge the Commission to approve the proposed Cash Out Tariff revisions.

V. SCRM

AGLC and CGC also continue its support for the proposed SCRM Tariff revisions. As discussed in their September 13, 2004 filing, AGLC and CGC have also been concerned that the current SCRM does not equitably distribute the costs that are recovered through the SCRM among the shippers that are responsible for generating those costs. Accordingly, AGLC and CGC support the proposed Tariff revision to the SCRM because it will result in a more equitable distribution of SCRM costs. Therefore, AGLC and CGC urge the Commission to approve the proposed SRCM Tariff revision.

VI. Conclusion

WHEREFORE, for the foregoing reasons, AGLC and CGC respectfully request that the Commission consider these initial post-technical conference comments in opposition to Southern's proposed PSC Out and Amendment of Primary Receipt Points revisions and in support of the proposed Cash Out and SCRM revisions.

Respectfully submitted,

/s/ Shannon Omia Pierce

Shannon Omia Pierce
AGL Resources Inc.
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309

Counsel for Atlanta Gas Light Company and Chattanooga Gas Company

January 7, 2005

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing "Initial Post-Technical Conference Comments of Atlanta Gas Light Company and Chattanooga Gas Company" upon each person designated on the electronic service list compiled at the December 9, 2004 Technical Conference in this proceeding.

Dated at Atlanta, Georgia this 7th day of January 2005

/s/ Shannon Omia Pierce

Shannon Omia Pierce
AGL Resources Inc.
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309

Submission Contents

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Chattanooga Gas Company
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EXHIBIT

G



April 29, 2005

Ms. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D. C. 20426

FILED
OFFICE OF THE
SECRETARY
2005 APR 29 A 11:42
FEDERAL ENERGY
REGULATORY COMMISSION

Re: Southern Natural Gas Company
Offer of Settlement
Docket Nos. RP04-523-000 and RP04-523-001

Dear Ms. Salas:

Pursuant to Rule 602 of the Rules of Practice and Procedures of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. Section 385.602 (2004), Southern Natural Gas Company ("Southern") submits for the Commission's approval an original and fourteen copies of the attached Stipulation and Agreement and its Appendices ("Settlement"). The Settlement will resolve all issues arising out of Southern's August 31, 2004, Section 4 general rate increase filing and is offered as an integrated, comprehensive resolution of the issues in the referenced proceeding.

Among other things, the Settlement, if approved and implemented pursuant to the terms thereof, provides for a resolution of all pending issues in this proceeding, including those tariff sheets approved in the Commission's February 28, 2005 Order in this proceeding, for which rehearing has been requested. The two parties with timely requests for rehearing of the February 28 Order have agreed as part of the Settlement to request the Commission to hold in abeyance such requests for rehearing until such time as the Settlement is approved; and, if the Settlement is approved, those parties have agreed to withdraw their requests for rehearing. Southern concurs with such requests to hold the requests for rehearing in abeyance until this Settlement can be approved. Prompt consideration and approval of this Settlement by the Commission will aid Southern and all parties by providing rate certainty to Southern and its customers.

Ms. Magalie Roman Salas
April 29, 2005
Page 2

This Settlement is a result of extensive negotiations and represents a delicate compromise of numerous, complex, interrelated issues and represents a consensus among virtually all of the active parties in the proceeding and the Commission Staff. The parties supporting, or not opposing, the Settlement represent approximately 99% of Southern's total system revenue requirements. The Settlement produces an overall result that is just and reasonable and in the public interest.

The Settlement must be considered as an integrated package. The isolation or alteration of any of the Settlement's individual components would disturb the negotiated compromise and the delicate balance of interests that has been reached among the parties. In addition, any modification of the Settlement will prevent the Settlement from becoming effective unless the modification is acceptable to Southern and not objected to by at least 25% of the intervenors in this proceeding.

As required by Rule 602(c), Southern hereby submits the following:

1. The attached Stipulation and Agreement and its Appendices constitute the settlement offer ("Settlement"). The Settlement includes:
 - Appendix A - Tariff Sheets which include the rates established pursuant to this Settlement and other terms and conditions agreed upon among the parties.
 - Appendix B - A complete listing of Southern's depreciation and amortization rates, including those not changed under the Settlement and the negative salvage rate.
 - Appendix C - A list of the converted South Georgia firm contracts; and
 - Appendix D - A list of shippers that have elected in writing and received by Southern not to extend all or a portion of one or more of their firm contracts; and
2. A separate Explanatory Statement.

As required by Rule 602 (c)(ii), Southern provides this Explanatory Statement for the convenience of the Commission and the parties. The Articles that comprise the Settlement are summarized below. In the event that this Explanatory Statement is inconsistent with any aspect of the Settlement, the provisions of the Settlement shall control.

Ms. Magalie Roman Sajas

April 29, 2005

Page 3

Southern respectfully requests that the Commission waive any and all regulations that may be necessary in order to permit the approval of this Settlement as filed. In accordance with Rule 602(d), Southern certifies that it is serving this offer of Settlement upon all parties of record in the referenced proceeding and those persons that typically are served with Southern's tariff or rate schedule filings. As required by Rule 602(d)(2), Southern hereby advises the parties that initial comments on the Settlement are due no later than 20 days after the filing date hereunder, and reply comments are due no later than 30 days after the filing date hereunder.

Respectfully Submitted,

SOUTHERN NATURAL GAS COMPANY



Patricia S. Francis
Senior Counsel
Southern Natural Gas Company
P.O. Box 2563
Birmingham, Alabama 35202-2563
(205) 325-7696

Patrick Pope
Vice President and General Counsel
Southern Natural Gas Company
P.O. Box 2563
Birmingham, Alabama 35202-2563
(205) 325-7126

Howard Nelson
Senior Counsel
El Paso Corporation
555 11th Street N.W.
Washington, D.C. 20004
(202) 637-3543

Mark Sundback
Andrews Kurth, LLP
1701 Pennsylvania Ave., NW
Suite 300
Washington, D.C. 20006
(202) 662-2700

1. The primary term(s) of each current two-part rate contract under Rate Schedules for FT and FT-NN service; and each current, non-small shipper Contract Storage Service ("CSS") agreement, including all contracts for firm service on the South Georgia facilities, as amended hereunder, which primary term(s) expire prior to August 31, 2010, will be extended through August 31, 2010. In addition, any contract under Rate Schedules FT, FT-NN or CSS under which a small shipper charge is applicable ("**Small Shipper Contract**") whose primary term expires prior to August 31, 2010 may, at the shipper's option, be extended through August 31, 2010. If a discounted rate granted under the March 10, 2000 Settlement currently applies to the contract quantity extended, but the discount expires prior to August 31, 2010, then any extensions as described above shall include an extension of such discount through August 31, 2010. Any seasonal mitigation in contract quantity or other sculpting provision implemented pursuant to Commission Order No. 636 will be continued during a term extended pursuant to this provision, except as such sculpting may have been modified for the converted South Georgia firm contracts, as more particularly shown in **Appendix C**. Further, such mitigated or sculpted contracts shall not be deemed to be seasonally adjusted contracts or discounted contracts for purposes of the ROFR regulations, if applicable. A request by a shipper to extend in conjunction with amending any other provisions of the contract that in Southern Natural's reasonable judgment reduces the value of the contract, including a request to

EXHIBIT

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The Settlement is the result of extensive negotiations between the parties and represents a fair and reasonable reconciliation of the parties' varying interests in this proceeding. The lower, than filed, transportation rates, additional fuel savings and rate certainty achieved by the Settlement will benefit AGLC, CGC, and their customers. AGLC and its customers will also benefit from the "roll-in" of the South Georgia facilities into the settlement rates. Additionally, approval of the Settlement will enable the parties to avoid significant litigation expenses. AGLC and CGC request that the Commission promptly approve the Settlement without any material modification so as to not disturb the compromise and balance of interests represented in the Settlement.

WHEREFORE, AGLC and CGC respectfully requests that the Presiding Administrative Law Judge promptly certify the Settlement to the Commission for approval and respectfully request that the Commission approve the Settlement, without material modification, as just, reasonable, and in the public interest.

Respectfully submitted,

/s/ Shannon Omia Pierce

Shannon Omia Pierce
AGL Resources Inc.
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309

Counsel for Atlanta Gas Light Company and Chattanooga Gas Company

May 19, 2005

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing "Initial Comments of Atlanta Gas Light Company and Chattanooga Gas Company in Support of Offer of Settlement" upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Atlanta, Georgia this 19th day of May 2005.

/s/ Shannon Omia Pierce

Shannon Omia Pierce
AGL Resources Inc.
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309

EXHIBIT

I



April 29, 2005

Ms. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D. C. 20426

FILED
OFFICE OF THE
SECRETARY
2005 APR 29 A 11:42
FEDERAL ENERGY
REGULATORY COMMISSION

Re: Southern Natural Gas Company
Offer of Settlement
Docket Nos. RP04-523-000 and RP04-523-001

Dear Ms. Salas:

Pursuant to Rule 602 of the Rules of Practice and Procedures of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. Section 385.602 (2004), Southern Natural Gas Company ("Southern") submits for the Commission's approval an original and fourteen copies of the attached Stipulation and Agreement and its Appendices ("Settlement"). The Settlement will resolve all issues arising out of Southern's August 31, 2004, Section 4 general rate increase filing and is offered as an integrated, comprehensive resolution of the issues in the referenced proceeding.

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Ms. Magalie Roman Salas
April 29, 2005
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 - Appendix D - A list of shippers that have elected in writing and received by Southern not to extend all or a portion of one or more of their firm contracts; and
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Ms. Magalie Roman Salas

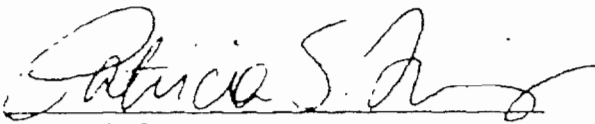
April 29, 2005

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reduce or otherwise sculpt seasonal contract quantities, shall be deemed an election not to extend; and that contract or that portion of the contract will be treated under Article III Paragraph 3. Southern Natural agrees that for the primary term of any firm contract being extended under this Article III Paragraph 1 or for the primary term of any firm contract that is exempt under Paragraph 5, the contract extension will provide for a cap of sixty (60) consecutive months on the maximum term that such shipper must match when exercising a ROFR under Section 20 of the GT&Cs at the termination of the primary term of such extension. This contractual ROFR cap of five years shall carry over to the contract of a replacement shipper if the contract is permanently assigned by the releasing shipper during the primary term of the contract.

2. For all contracts extended under the preceding paragraph and whose provision for giving notice to Southern Natural prior to termination is less than three hundred and sixty five (365) calendar days, each Consenting Party (as that term is defined in Article XIII, Paragraph 3(a)) agrees that such prior notice period for termination at the end of the primary term or any evergreen period shall be amended to 365 days.

3. Appendix D hereto lists shippers that have elected in a writing received by Southern Natural not to extend all or a portion of one or more of their firm contracts. With respect to those contract quantities for which those shippers have elected not to extend, such shippers agree to pay, in lieu of the applicable

EXHIBIT

J



April 29, 2005

Ms. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D. C. 20426

FILED
OFFICE OF THE
SECRETARY
2005 APR 29 A 11:42
FEDERAL ENERGY
REGULATORY COMMISSION

Re: Southern Natural Gas Company
Offer of Settlement
Docket Nos. RP04-523-000 and RP04-523-001

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Ms. Magalie Roman Salas

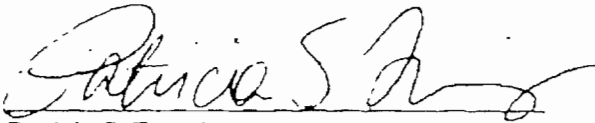
April 29, 2005

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(202) 662-2700

APPENDIX D

CONTRACTS NOT EXTENDED

Appendix D

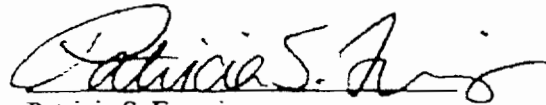
Southern Natural Gas Company Docket No. RP04-523

<u>SHIPPER</u>	<u>Mcf/d</u>
Alabama Gas Corporation	1,959
Atmos Energy Corporation - MidStates	5,000
Cheney Lime and Cement Company	147
Enterprise Alabama Intrastate LLC	1,592
G-P Gypsum Corporation	3,090
Gulf States Paper Corporation	712
Industrial Insulations Group LLC	500
International Paper Company	3,918
Jefferson-Cocke County Utility District	350
Knoxville Utilities Board	10,000
Middle Tennessee Natural Gas Utility District	1,000
Northwest Alabama Gas District	5,000
Oak Ridge Utility District	100
Occidental Chemical Corporation	600
Oglethorpe Power Corporation	161,606
Powell Clinch Utility District	500
Shell Offshore Inc	140,000
SP Newsprint Co	7,581

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding via first-class mail.

Dated at Birmingham, Alabama, this 29th day of April, 2005.

A handwritten signature in black ink, appearing to read "Patricia S. Francis". The signature is fluid and cursive, with a large initial "P" and a stylized "F".

Patricia S. Francis
Senior Counsel
Southern Natural Gas Company
1900 5th Avenue North
Birmingham, AL 35203
(205)325-7696

EXHIBIT

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DAV/jr

1

1 UNITED STATES OF AMERICA
2 FEDERAL ENERGY REGULATORY COMMISSION
3

4 - - - - - x

5 IN THE MATTER OF: : Docket Number

6 STATE OF THE NATURAL GAS : PL04-17-000

7 INDUSTRY CONFERENCE :

8 STAFF REPORT ON NATURAL GAS : AD04-11-000

9 STORAGE :

10 - - - - - x

11

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Hearing Room 2C

13

Federal Energy Regulatory

14

Commission

15

888 First Street, NE

16

Washington, D.C.

17

18

Thursday, October 21, 2004

19

20

The above-entitled matter came on for hearing,
21 pursuant to notice, at 9:10 a.m.

22

23

PRESIDING:

24

BERNE MOSLEY, OEP, presiding

25

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DAV/jr

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1 pricing corollary in the pipeline industry I would suggest
2 you consider along with market-based rates.

3 I think I've probably used my time, and exhausted
4 my comments at this stage.

5 MR. MOSLEY: Thank you, Mr. Dickerson. Mr. Oaks.

6 MR. OAKS: Good afternoon. I'd like to thank the
7 Commission for this opportunity to speak. I'm Tim Oaks from
8 UGI Utilities, Inc., in eastern Pennsylvania. Today, I'm
9 speaking on behalf of the American Gas Association.

10 I'd like to cover three topics today. The first
11 topic is LDC use of storage. AGA is concerned for some time
12 now that there seems to be some misconception about how LDCs
13 use storage, how we contract for it, how we plan for it, how
14 we use it. In fact, I heard some of those misconceptions
15 already today. Then I will move on to the topic of this
16 panel, the uncommitted reserve capacity, and then finally a
17 brief discussion about some market rates.

18 AGA members represent 90 percent of the gas that
19 is delivered at retail in this country. As the staff report
20 points out, we hold the majority of storage. We hold that
21 storage for both the merchant and delivery functions that we
22 provide. We utilize storage to meet retail obligations. We
23 assure that we meet our winter requirements through storage.
24 This morning I heard storage is an optional service. For
25 LDC's it's not an optional service. It's a critical

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1 component to what we do. It provides a large portion of our
2 deliveries at the time deliveries are most critical. We
3 focus our planning on delivering for a firm, reliable
4 service. This cannot be overemphasized.

5 While we do use storage for other reasons, like
6 price hedging, daily balancing, and no notice service, those
7 unfortunate consequences of holding storage, our planning
8 focus is still firm, reliable deliveries.

9 In my slides, I present a graph which is sort of
10 gas supply planning 101. It provides something called a
11 load duration curve, a bit of an unusual curve in that it
12 resorts temperatures from coldest to warmest. It provides a
13 quick profile of how LDCs face temperature sensitivity
14 during the winter season. The planning focus of any LDC is
15 to optimize its capacity portfolio to meet that load
16 duration curve. We want to do two things. We want to
17 maintain reliable service, and we want to meet it at least
18 cost. We want to minimize fixed costs.

19 The second graph in the handout superimposes
20 capacities on that load duration curve. The lines and step
21 lines you see on that graph are representative of an
22 optimized portfolio. It can be broken into three parts, as
23 you know. FT, which is the flat line, which represents how
24 firm transportation is more a base load serving capacity.
25 Storage, which are the step lines immediately above firm
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1 transportation, which serve to sculpt our capacities in a
2 form that meets the demand requirements of the system. And
3 then finally peak shaving, which is the step line at the
4 very top for the very coldest days.

5 The third graph focuses on storage. Sculpting of
6 storage creates three level of storage that LDCs contract
7 for. I call the first new peak, approximately 20 days or
8 less storage. The next one intermediate storage, which runs
9 from 25 to 75 days, and then finally seasonal storage, which
10 tends to run from 75 days to 150 days, the full winter
11 season.

12 These differing levels of service are the primary
13 tools for optimizing our contracts and for maintaining least
14 cost. They also are part of close scrutiny by state
15 commissions.

16 As I pointed out earlier, they are the primary
17 components of our portfolio for the meeting of winter
18 requirements. The next graph focuses on some of the
19 benefits we receive from helping storage. We do use the
20 price hedge of the summer injection versus winter
21 withdrawals. While those benefits have lessened or become
22 less assured over the last few years, those things still
23 exist and we do use that physical hedge. There seems to be
24 confusion regarding how LDCs inject storage versus price
25 plays. Price plays generally are handed by marketers.

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1 Virtually all LDCs are injecting during summer season. Even
2 if the price levels we are experiencing on future NYMEX
3 contracts are decreasing as we go through the winter, we
4 will be injecting storage. We have no choice but to inject.
5 The obligations to serve our firm customers outweigh any
6 price. It's also been pointed out that storage injection
7 capacities are often less than withdrawal capacities.
8 Therefore, to the extent that we have longer storage
9 services in the form of seasonal service, seasonal storage
10 or intermediate storage, it generally takes most of the
11 summer to inject those gases. Again, most price spikes come
12 from the marketers.

13 Finally, summer injections. The differential in
14 prices between summer injections and winter prices has, at
15 times, become less pronounced because of the lack of
16 competition in the summer months.

17 Just to summarize the things we focus on: the
18 obligation to serve firm service drives all planning. In
19 early November, all LDCs are close to full inventory. On
20 March 31st, they're all close to empty. We take one full
21 term for most of our services. There are variances in
22 storage injections during the summer we realize, but it is
23 not coming from the LDCs. While we do make some adjustments
24 based on price levels, given the limited flexibility that
25 exists in storage contracts, we will still fill storage.

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1 Also, in addition, most LDC storage is market area.

2 Generally, reservoirs or aquifers, having only
3 one term per year, generally what we do is we fill
4 throughout the entire summer and withdraw during the winter
5 season. While we do hold some production area storage,
6 those are mainly for commodity reasons, for replacement of
7 supply during well freeze offs for short-term least cost
8 activities.

9 I'd now like to turn to the question of
10 uncommitted reserves. Certainly, simple supply and demand
11 theory would suggest that additional capacity would reduce
12 volatility. I'd like to point out, however, that capacity
13 constraints are only half of the equation. Indeed, some
14 additional capacity might limit some of the upward
15 volatility on demand pressures, putting pressure on higher
16 prices. However, the other half of the equation, and I
17 would argue maybe more than half of the equation, is the
18 availability of the commodity itself. As long as supply
19 remains tight, volatility will remain.

20 While AGA finds the idea of uncommitted reserves
21 an interesting idea, we have some concerns. The first is
22 obviously cost allocation. We're moving to the bottom line.
23 Who pays? This raises other questions. What is the
24 appropriate level of service for each pipeline? Is it
25 different for each pipeline? Is it different regionally?
26

17200
DAV/jr

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1 Does the pipeline earn a fair return? I guess I know the
2 pipeline's answer on that one. How is the construction
3 certificated and financed?

4 The second issue AGA has is the nature of the
5 demand pressure that we're currently seeing. As I have
6 emphasized earlier, LDCs focus on our core responsibility:
7 our obligation to serve. We design and contract where a
8 portfolio can meet our design loads. Therefore, the LDC
9 loads are not a surprise in peak situations. We are not
10 adding to any shortage of capacity. Much of the pressure
11 appears to be coming from interruptible loads. We remain on
12 at near peak situations primarily from electric generation
13 and other industrial loads.

14 These entities have made the economic decision to
15 shun from capacity. In doing so, they're sending the wrong
16 market signals. They're increasing demand into those
17 situations and are attempting to commoditize the capacity
18 market while LDCs pay the fixed cost on an annual basis.
19 Given this reality, creating what would in essence be
20 additional capacity to exacerbate reliance on inappropriate
21 services during peak conditions, the LDCs will stand firmly
22 against subsidizing excess interruptible capacity that would
23 be created through a mandate to build reserve capacity. If
24 a reserve margin develops through market forces, that is
25 another matter. The market will be signaling a willingness
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DAV/jr

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1 to pay and a subsidization issue would not come into play.
2 For example, some state commissions already require LDCs to
3 contract for reserve capacity. Margins for reliability
4 purposes, but holding reserves to build into a contract
5 portfolio is different than a mandate. That would create
6 excess uncommitted capacity in the market.

7 Third, LDCs are concerned about the effect that
8 extra capacity will have on the capacity release market.
9 Under Order 636, the capacity release mechanism is directly
10 tied to the recognition that firm customers needed a means
11 to mitigate fixed costs. Additional unused capacity, which
12 from a planning standpoint would be available at virtually
13 100 percent of the time, will significantly reduce the value
14 of capacity in the release market, thereby weakening the
15 cost mitigation we received under 636. Such an event would
16 necessitate reconsideration of the regulatory impact we
17 received under Order 636.

18 Finally, AGA would like to turn its attention
19 briefly to market-based rates. The staff report points out
20 that several proposed storage projects have been delayed or
21 canceled. The staff report also points out that right now
22 we have about sufficient level of storage. We need to meet
23 projected storage growth. LDCs have been meeting with
24 pipelines and independent project developers. At times, we
25 signal our willingness to buy in, and at other times, the
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17200
DAV/jr

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1 economics just are not right for us.

2 The recent Duke Project, which received a
3 significant amount of attention from LDCs on Texas Eastern
4 and Algonquin indicates our willingness to acquire
5 additional storage. It appears the economics don't make
6 sense. The buyers are not interested or the promoters will
7 cancel or delay that. And sometimes the transportation tied
8 to the storage just doesn't work for the project.

9 Accordingly, AGA supports the staff proposal to
10 relax or broaden the current market-based rates test to spur
11 more storage development. Another option might be to
12 develop incentives to spur storage development. In a fair
13 market, if a party is interested, it will make a rational
14 decision. The market will bear the market-based rates, and
15 there is no reason to foreclose that option.

16 Critical for consumer protection are the staff's
17 provisions that discuss assuring that all market risks lay
18 with the projects' owners, and no captive customers are
19 involved in the project. Additionally, periodic review of
20 market-based rate storage services would be an important
21 check on the continued appropriateness of the rate-based
22 authority. The good news is that we are not in a critical
23 situation today, and efforts like today's conference should
24 prevent it in the future. Thank you

25 MR. MOSLEY: Thank you, Mr. Oaks. Next is Mr.

26

EXHIBIT

L

**FERC Conference on
State of the Natural Gas Industry – Storage
October 21, 2004**

**Comments of
Tim Oaks
UGI Utilities Inc
Manager – Federal Regulatory Affairs
On Behalf of
The American Gas Association**

**FERC Conference on
State of the Natural Gas Industry – Storage
October 21, 2004**

◆ Topics:

- ✓ LDCs use of storage.
- ✓ Uncommitted Capacity
- ✓ Market Based Rates

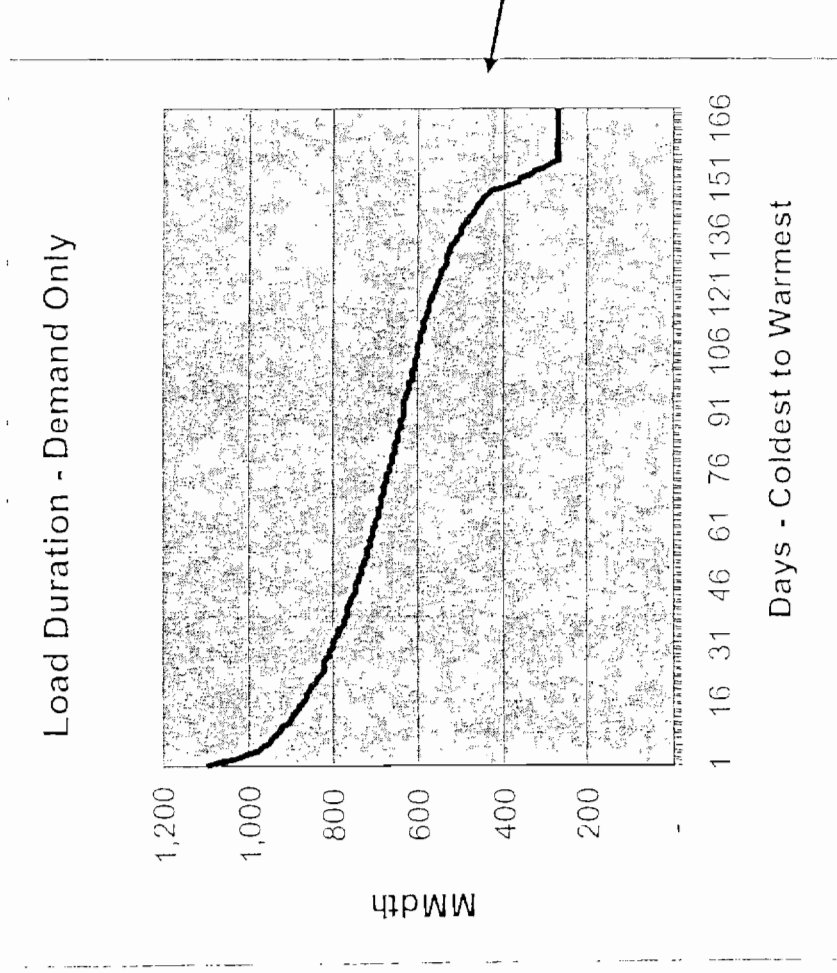
FERC Conference on
State of the Natural Gas Industry – Storage
October 21, 2004

- ◆ LDCs use of storage.
- ◆ LDCs hold the majority of storage contracts
- ◆ LDCs utilize storage as a tool for meeting their retail obligations

**FERC Conference on
State of the Natural Gas Industry – Storage
October 21, 2004**

- ◆ Storage is acquired to ensure LDCs can reliably serve our peak, firm markets.
- ✓ Cannot be over emphasized
- ✓ LDCs use storage for other reasons, like price hedging, this is a fortunate consequence of operations of storage, but NOT the driving force in planning.

FERC Conference on State of the Natural Gas Industry – Storage October 21, 2004



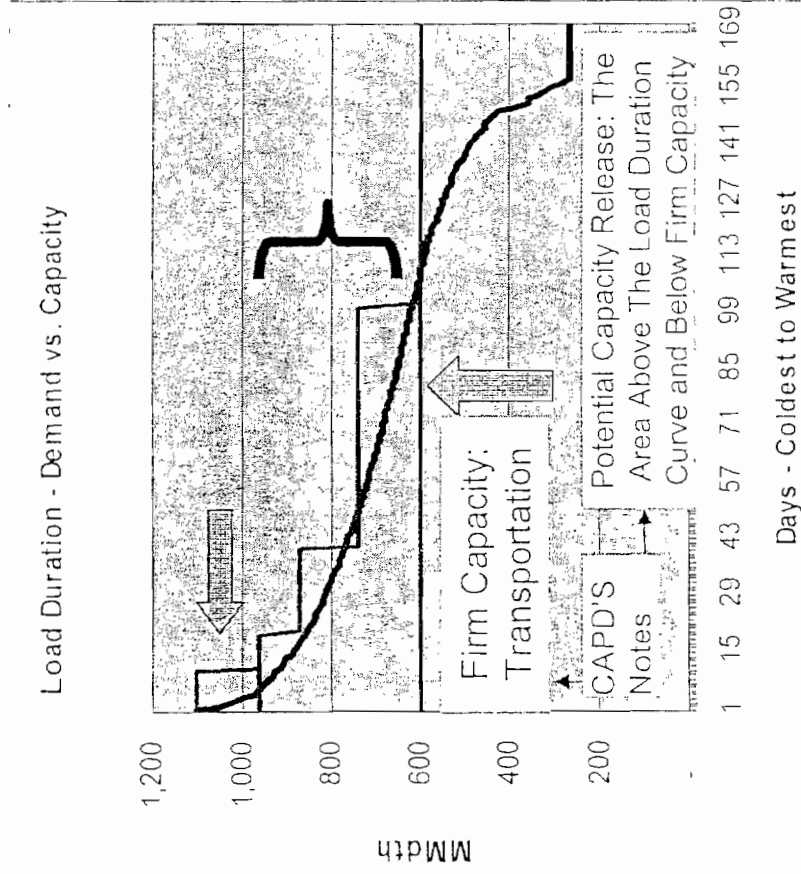
- Typical Load Duration
- From a Demand Standpoint
- Winter
- Summer
- Storage Injections
 - Increase Summer Needs
- Optimize the Portfolio of Capacity Services



American Gas Association



FERC Conference on State of the Natural Gas Industry – Storage October 21, 2004

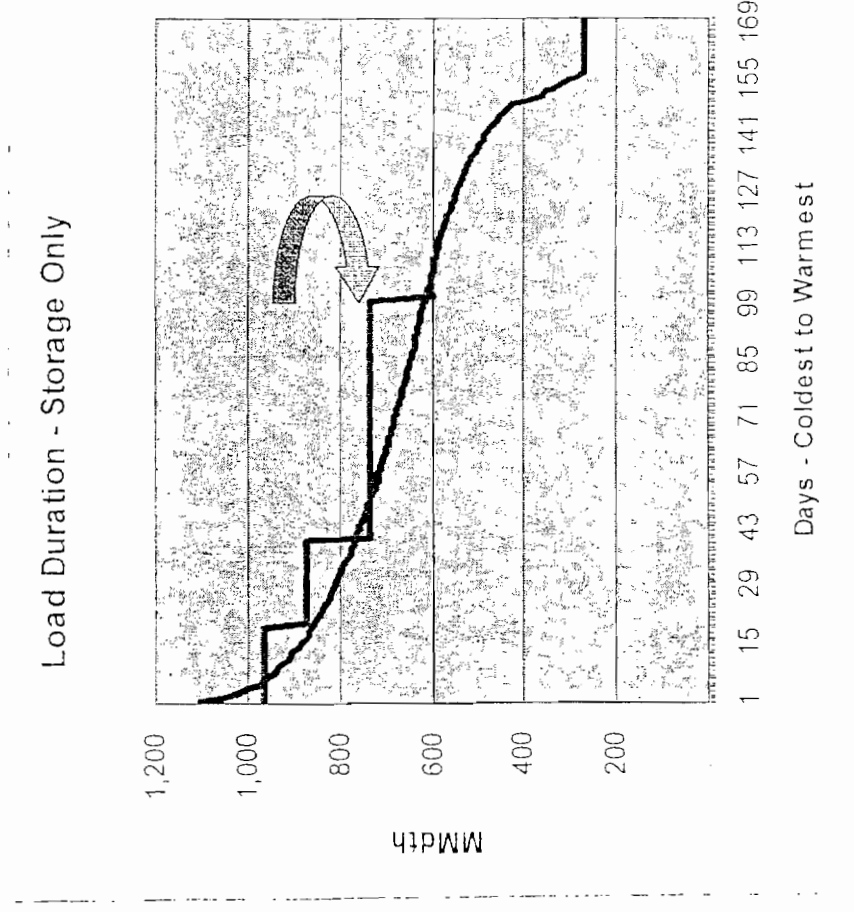


- Adds Supply/Capacity to the Load Duration
 - Broken into three Parts
 - Flowing Gas (FT)
 - Storage Withdrawals
 - Peak Shaving
- Minimize Fixed Costs & Optimize Assets

FERC Conference on State of the Natural Gas Industry – Storage October 21, 2004

Storage

- Multiple Options – Days of Service
 - Near Peak (20 days or less)
 - Intermediate (25 to 70 days)
 - Seasonal (75 to 150 days)
 - Number of Turns
- Optimization of Contract Profile
 - Least Cost Capacity Mix
 - State Regulatory Scrutiny

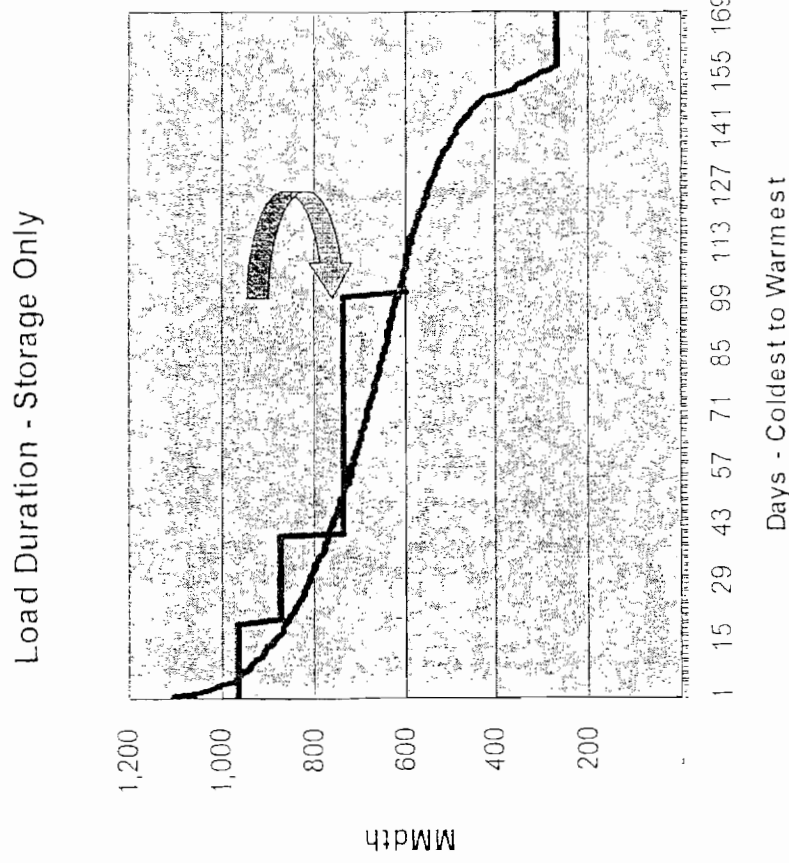


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Storage

➤ Seasonal Pricing issues

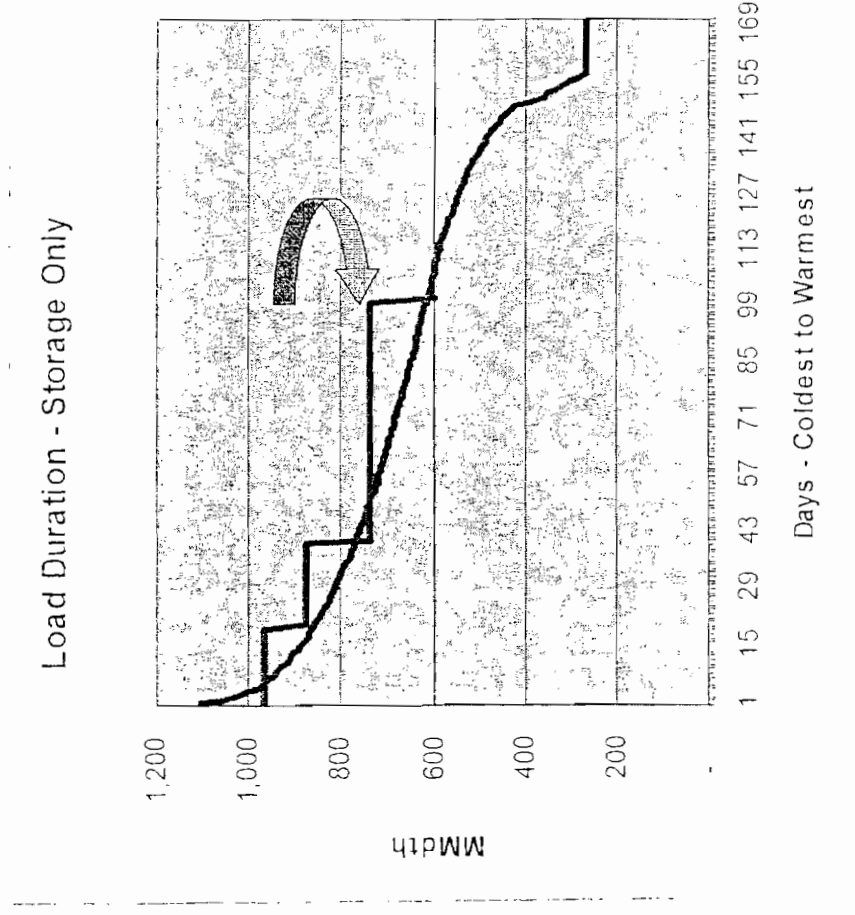
- Summer/Winter price Difference Physical Hedge
- Summer Fill for LDC vs. Price Plays for Marketers
- The Affect of Summer Electric Generation.
- Seasonal Price Differential has shrunk in recent years



FERC Conference on State of the Natural Gas Industry – Storage October 21, 2004

Storage

- Obligation to Serve Drives Planning
- LDCs at or near Full Inventory in November
 - Different from marketers – less price plays
- Market area versus Production area
 - Market area services generally Summer injection, Winter withdrawal (i.e. 1 turn)
 - Production area services have the ability to quickly refill and withdraw (i.e. multiple turns all year round)



**FERC Conference on
State of the Natural Gas Industry – Storage
October 21, 2004**

- ◆ Uncommitted reserves for storage and FT
 - ✓ Supply and demand would suggest this could help reduce volatility in prices.
 - ✓ Capacity constraints are only half of this equation
 - ✓ Other half of the equation is the availability of the commodity itself
 - ✓ As long as supply remains tight, volatility will remain

TRA DOCKET NUMBER 07-00224

EXHIBIT B

FERC Order 637 supports Dr. Brown's
opinions on the following subjects.

ON THE DEVELOPMENT OF MARKET CENTERS

“Market centers began to develop to facilitate the buying and selling of natural gas and, in 1990, NYMEX established a futures market using the Henry Hub as the market exchange center. Shippers and marketers began to use the capacity release mechanism as an alternative to obtaining transportation service from the pipeline, particularly for short-term service.” Page 7 {Page numbers refer to the pages in the copy of 637 given to CGC by CAPD}

“Market centers: In order for producers and marketers to serve LDCs and other customers, active wholesale markets have developed upstream (in production areas) and they are growing in downstream markets as well. Gas customers have the choice of entering into long-term gas contracts to assure supply or price or they can rely upon monthly and daily spot markets to obtain their gas supplies. Customers further have the option of buying gas at upstream market centers in the production area or at market centers in downstream markets. A market center is a point of interconnection between pipelines where traders can exchange gas and shippers can obtain a variety of services, including gas trading, wheeling, parking, loaning, storage, and transfer facilities.” Page 11.

ON CGC'S OPPORTUNITY TO TURNBACK CAPACITY
FROM 2000 TO 2005.

“LDCs are considering whether to continue their current firm-to-the-wellhead capacity contracts or whether to reduce their contractual entitlements or to rely more heavily on purchasing gas from producers or gas marketers at downstream market centers or trading points. It is not clear whether marketers will choose to pick up all or some of the firm capacity relinquished by LDCs. Marketers' purchase of firm capacity, for instance, has been increasing, with their holdings increasing by 18% during the 12-months ending July 1, 1998...” Page 25.

1 *“The increasing use of asset managers by LDCs and other*
2 *shippers to manage their pipeline capacity could result in the*
3 *concentration of pipeline capacity in a few hands, reducing the*
4 *competitiveness of the capacity resale market.” Page 29.*
5

6
7 ON COST BENEFIT ANALYSIS OF AN LNG PLANT
8

9 *“Similarly, an LDC might have a peak shaving capability (storage*
10 *or liquefied natural gas (LNG)) that costs more to produce and*
11 *deliver gas than purchasing the gas in upstream markets and using*
12 *its transportation capacity to transport that gas to its citygate. The*
13 *LDC might be willing to release its transportation capacity and*
14 *use the peak shaving device instead if it could receive a price*
15 *above the maximum rate for its transportation capacity so that the*
16 *amount it receives for the release of its transportation capacity*
17 *covers the costs of the peak shaving device. Page 68.*
18

19 *[Footnote 93 at this paragraph says further: ‘Suppose the costs to*
20 *the LDC of using the peak shaving device were \$6.00/MMBtu and*
21 *the costs of buying gas in the upstream market was \$4.00/MMBtu*
22 *with a \$.10/MMBtu usage charge (under its firm contract) for*
23 *transportation. If the LDC could resell its transportation capacity*
24 *for more than \$1.90/MMBtu (the difference between using its peak*
25 *shaving device and its transportation service), it would release that*
26 *capacity and use its peak shaving instead. If the release were*
27 *subject to a maximum cap of less than \$1.90, however, the LDC*
28 *would choose not to peak shave and the capacity would not be*
29 *released to others.’*
30

31
32 ON CGC’S RECEIPT CAPACITY AT RIDGETOP
33 BEING VALUABLE TO SEQUENT FOR ITS SALES TO
34 THE TRANSCO MARKETS:
35

36 *“The use of released capacity has made possible the development*
37 *of virtual pipelines. A virtual pipeline can be created when a*
38 *marketer or other shipper acquires capacity on interconnecting*
39 *pipelines and can schedule gas supplies across the interconnect,*
40 *creating in effect a new pipeline between receipt and delivery*
41 *points that are not physically connected under a single pipeline*
42 *management.” Page 18*
43

“The ability to use flexible receipt and delivery point rights and to segment capacity enhances the value of firm capacity and the ability of firm capacity holders to compete with capacity available from the pipeline as well as capacity available from other releasing shippers. In the example used in Order No. 636, a shipper holding firm capacity from a primary receipt point in the Gulf of Mexico to primary delivery points in New York could release that capacity to a replacement shipper moving gas from the Gulf to Atlanta while the New York releasing shipper could inject gas downstream of Atlanta and use the remainder of the capacity to deliver the gas to New York. In order for such a transaction to work, both the releasing and replacement shippers need the right to change their receipt and delivery points from the primary points in their contracts to use other available points.” Page 128, 129.

“Information on the amount of capacity available at receipt and delivery points and on mainline segments, as well as on the daily amount of capacity that pipelines schedule at these points, helps shippers structure gas transactions and casts light on whether shippers or the pipeline may be withholding capacity.” Page 178.

ON FERC’S CUSTOMER INDEX, RECEIPT CAPACITY
AND DELIVERY CAPACITY REPORTING AS PUBLIC
RECORDS :

“Therefore, the Commission is revising its reporting requirements in a few main respects to improve the availability and usefulness of the information currently reported. First, the Commission is changing and consolidating the reporting formats in which it collects the information, including the time frames within which information is reported, to enable the Commission to equalize the reporting requirements for capacity release transactions and pipeline transactions, and to simplify the overall reporting system. The new reporting system reduces the amount of periodic reporting to the Commission currently required, and instead relies on Internet posting and maintenance of information. Second, the Commission is adding certain data to the information that is already collected on pipeline transactions, the structure of the market, and capacity availability in various reporting formats. Specifically, the most significant additional information being required here is receipt and delivery point data in the report on pipeline transactions and the Index of Customers, certain organizational and personnel information on affiliates, and information on design and scheduled capacity and service outages. Third, the Commission is reorganizing its regulations to consolidate all of the existing and new Part 284 reporting requirements into a single, new Section 284.13 governing open-access reporting requirements for interstate pipelines.” Page 179.

ON THE DETERMINING THE GROWTH OF GAS
RECEIPTS AND GAS DELIVERIES ON ETNG BY
SPECIFIC POINTS SINCE 2002:

“Specifically, for firm service, pipelines will be required to post the following information, contemporaneously with the execution of the contract.” Page 181.

1 *“Information on Available Capacity. In section 284.8(b)(3) of the*
2 *Commission's existing regulations, pipelines are required to post*
3 *information about the amount of operationally available capacity*
4 *at receipt and delivery points, on the mainline, in storage fields,*
5 *and whether the capacity is available directly from the pipeline or*
6 *through capacity release. In new section 284.13(d)(1), being*
7 *adopted here, the Commission is continuing to require that*
8 *pipelines post this information, and is adding the following*
9 *information on capacity availability to the information that is*
10 *already collected: the total design capacity of the point or*
11 *segment; the amount of capacity scheduled at each point on a daily*
12 *basis; and information on planned and actual service outages that*
13 *would reduce the amount of capacity available.” Page 205.*

14
15
16
17 ON THE NEED FOR STATE REGULATORY AGENCIES
18 TO HAVE A FULL PICTURE OF THE GAS INDUSTRY.

19
20 *“But monitoring, by itself, is not sufficient to develop a full picture*
21 *of the trends in the industry. It is important for all segments of the*
22 *industry to engage in a dialog to consider how industry changes do*
23 *or should affect Commission regulatory policy. Such a dialog will*
24 *enable the Commission and state regulators to achieve a better*
25 *understanding of industry trends and regulatory changes that*
26 *better meet the changing character of the industry.” Page 49*

27
28
29
30 ON THE NEED FOR CGC TO SEEK OUT ETNG
31 SEASONAL CAPACITY AND REDUCE YEAR-ROUND
32 CAPACITY
33

1 *“The removal of the rate ceiling for short-term capacity release*
2 *transactions and the ability of pipelines to institute peak/off-peak*
3 *and term-differentiated rates should help to reduce the cost of*
4 *capacity to captive customers. The captive customers currently pay*
5 *maximum rates for transportation capacity during peak and off-*
6 *peak periods to support the pipeline system, while short-term*
7 *shippers benefit by paying lower market prices during off-peak*
8 *periods reflecting the reduced demand on the system, but do not*
9 *face the market rate for capacity during peak periods as a result of*
10 *the rate ceiling. The changes in ratemaking policies adopted in this*
11 *rule will help to reduce the revenue responsibility of captive*
12 *customers by placing on short-term shippers more of the burden of*
13 *paying for peak period usage of the system. The Commission's*
14 *objective is for the reduction in captive customers' revenue*
15 *responsibility to be achieved through a combination of increased*
16 *capacity release revenues, as well as revenue credits, reduced*
17 *discount adjustments, and lower long-term rates on pipelines*
18 *instituting peak/off-peak or term-differentiated rates.” Page 36, 37*
19

20 In addition to FERC Order 637, PIEDMONT
21 NATURAL GAS Company's filing in on January
22 9, 2003 in FERC Docket RM98-10-012,
23 supports Dr. Brown's opinion that CGC's
24 policy of maintaining year-round firm
25 transportation on ETNG (which is largely
26 underused by CGC's firm customers) is
27 advantageous to CGC and its asset manager,
28 Sequent
29

30 *“These changes in Commission policy took the first major steps*
31 *toward creating a competitive interstate natural gas pipeline grid,*
32 *where shippers could use the capacity they contracted for not only*
33 *to facilitate flexible deliveries for their own use but could also*
34 *utilize that capacity to compete with the pipelines themselves –*
35 *through capacity release transactions – when the capacity was not*
36 *needed to serve their own customers [emphasis added by CAPD].”*
37 *[Piedmont , Pages 11-12].*
38

39 As Dr. Brown's testimony shows, CGC's firm
40 transportation capacity from ETNG' is largely underused
41 and therefore available for purposes other than meeting
42 the needs of firm customers.

TRA DOCKET NUMBER 07-00224

EXHIBIT C

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 154, 161, 250, and 284

[Docket Nos. RM98-10-000 & RM98-12-000; Order No. 637]

Regulation of Short-Term Natural Gas Transportation Services, and
Regulation of Interstate Natural Gas Transportation Services

(Issued February 9, 2000)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. In this rule, the Commission is revising its current regulatory framework to improve the efficiency of the market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power. The rule revises Commission pricing policy to enhance the efficiency of the market by waiving price ceilings for short-term released capacity for a two year period and permitting pipelines to file for peak/off-peak and term differentiated rate structures. It effects changes in regulations relating to scheduling procedures, capacity segmentation and pipeline penalties to improve the competitiveness and efficiency of the interstate pipeline grid. It narrows the right of first refusal to remove economic biases in the current rule,

while still protecting captive customers' ability to resubscribe to long-term capacity. And, it improves the Commission's reporting requirements to provide more transparent pricing information and permit more effective monitoring of the market.

DATES: The rule will become effective [insert date 30 days after publication in the Federal Register], with the exception of the removal of paragraph (c)(6) of redesignated section 284.10, which will be effective on September 1, 2000. Pro forma tariff filings to comply with certain requirements of the rule are due by May 1, 2000. Changes to reporting requirements are to be implemented by September 1, 2000.

ADDRESSES: Federal Energy Regulatory Commission
888 First Street, N.E.
Washington DC, 20426

FOR FURTHER INFORMATION CONTACT:

Michael Goldenberg
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426.

(202) 208-2294

Robert A. Flanders
Office of Markets, Tariffs, and Rates
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426.

(202) 208-2084

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of Short-Term Natural
Gas Transportation Services

Docket No. RM98-10-000

Regulation of Interstate Natural
Gas Transportation Services

Docket No. RM98-12-000

ORDER NO. 637

FINAL RULE

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

Regulation of Short-Term Natural
Gas Transportation Services

Docket No. RM98-10-000

Regulation of Interstate Natural
Gas Transportation Services

Docket No. RM98-12-000

ORDER NO. 637

FINAL RULE

(Issued February 9, 2000)

The Federal Energy Regulatory Commission (Commission) is amending Part 284 of its open access regulations in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. In this rule, the Commission is revising its current regulatory framework to improve the efficiency of the market and to provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power. To this end, the final rule makes the following changes in the Commission's current regulatory model:

- The rule grants a waiver for a limited period of the price ceiling for short-term released capacity to enhance the efficiency of the market while continuing regulation of pipeline rates and services to provide protection against the exercise of market power.

- The rule revises the Commission's regulatory approach to pipeline pricing by permitting pipelines to propose peak/off-peak and term differentiated rate structures. Peak/off-peak rates can better accommodate rate regulation to the seasonal demands of the market, while term differentiated rates can be used to better allocate the underlying risk of contracting to both shippers and pipelines.
- The rule adds regulations to improve the competitiveness and efficiency of the interstate pipeline grid by making changes in regulations relating to scheduling procedures, capacity segmentation and pipeline penalties.
- The rule narrows the right of first refusal to remove economic biases in the current rule, while still protecting captive customers' ability to resubscribe to long-term capacity.
- The rule improves reporting requirements to provide more transparent pricing information and to permit more effective monitoring for the exercise of market power and undue discrimination.

While the regulatory revisions adopted in this rule primarily affect the regulation of short-term transportation options, the changing nature of the natural gas market also poses significant challenges to the Commission's current model for regulating long-term transportation capacity. Changing the Commission's fundamental regulatory model goes beyond the scope of this proceeding. However, the Commission is beginning a new effort to monitor the changes taking place in the market so that, after this rulemaking terminates, the Commission can be prepared to reexamine its regulatory framework in light of the challenges posed by the growing competitive market.

The changes in the gas market since wellhead decontrol and Order Nos. 436 and 636 have created a better functioning and more reliable gas market. But the very growth of a more efficient market for natural gas and transportation capacity poses significant

challenges to the Commission's regulatory model which was developed when the market was not competitive or efficient. The Commission discusses below the growth that has occurred in the market since Order No. 636, the current trends and their regulatory implications. The Commission then discusses its regulatory objectives and why the Commission is instituting a new process, independent of this proceeding, to examine whether fundamental changes to its current regulatory framework are needed to respond to the changed structure of the natural gas market. In Parts II through VII, the Commission discusses the adjustments to its current regulatory model that it is making in this rule.

I. INTRODUCTION

A. The Changing Natural Gas Market

1. Prologue to Competition

Prior to Order Nos. 436 and 636, and the implementation of the Wellhead Decontrol Act, all aspects of the natural gas market were regulated. The Commission, pursuant to the dictates of the Natural Gas Act (NGA)¹ and then the Natural Gas Policy Act (NGPA) established the prices for natural gas. Interstate pipelines purchased gas at the wellhead and delivered that gas at regulated rates to local distribution companies (LDCs). The LDCs, in turn, distributed gas to industrial, commercial, and residential consumers at rates regulated by the states, which permitted passthrough of the interstate

¹Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954) (mandating Commission regulation of the gas commodity).

pipeline costs. There was little choice in the market for natural gas or the market for transportation capacity. The market distortions and inefficiencies created by this regulatory regime are well known. The regulation of natural gas prices created economic incentives for producers to divert interstate gas to the unregulated intrastate market where they could obtain higher prices. The regulated prices dampened the incentive to invest in the production of natural gas, which led to the gas shortages in the 1970's.²

The passage of the Natural Gas Policy Act (NGPA)³ in 1978 began to alleviate the problems caused by regulation of the gas commodity by regulating both interstate and intrastate gas prices in an effort to limit the incentives for diversion of gas, seeking to break down the artificial barriers between interstate and intrastate gas markets, and gradually providing for deregulation of natural gas prices. In 1985, in response to the changed market conditions created by the NGPA, the Commission adopted Order No. 436⁴ which established rules for pipelines to offer open access transportation service independent of pipelines' sales service. In 1989, Congress passed the Wellhead Decontrol

²See *Transcontinental Gas Pipe Line Corporation v. State Oil & Gas Board*, 474 U.S. 409 (1986) (NGA's artificial pricing scheme major cause of imbalance between supply and demand); *Public Service Commission of New York v. Mid-Louisiana Gas Co.*, 463 U.S. 319, 30-31 (1983) (interstate natural gas prices could not compete with intrastate prices).

³15 U.S.C. 3301-3432 (1978).

⁴Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol. Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. Regulations Preambles [1982-1985] ¶ 30,665, at 31,472-74 (Oct. 9, 1985).

Act⁵ which removed all regulation from the gas commodity by 1993. In passing the Wellhead Decontrol Act, Congress assigned to the Commission the task of regulating interstate pipeline capacity in a way that would "maximize the benefits of [wellhead] decontrol."⁶

In Order No. 636,⁷ the Commission found that the pipelines' provision of a bundled gas and transportation service had anticompetitive effects that limited the benefits of open access service and wellhead decontrol. The Commission, therefore, required pipelines to separate their sales of gas from their transportation service and to provide comparable transportation service to all shippers whether they purchase gas from the pipeline or another gas seller. The Commission further adopted initiatives to increase competition for pipeline capacity in order to reduce the prices paid for transportation and ultimately the overall price consumers pay for gas. The Commission allowed firm holders of pipeline capacity to resell or release their capacity to other shippers and required pipelines to permit shippers to use flexible receipt and delivery points. Enabling firm shippers to resell their capacity created competitive alternatives to purchasing

⁵Pub. L. No.101-60 (1989); 15 U.S.C. § 3431 (b)(1)(A) (as of Jan. 1, 1993, any amount paid for a first sales of natural gas is just and reasonable).

⁶Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101-29, 101st Cong., 1st Sess., at 6 (1989).

⁷Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,939 (Apr. 8, 1992).

pipeline services. The ability to use flexible receipt or delivery points also expanded the capacity alternatives available to buyers of capacity because it meant that buyers were not restricted to using the primary points in the releasing shipper's contract. Capacity buyers could seek capacity from any number of firm capacity holders and use flexible point authority to inject and deliver gas at the points the purchasing shipper chose to use.

The combination of wellhead decontrol, open access transportation, and the unbundling of pipeline gas sales from the pipelines' transportation function created an opportunity for increased efficiency and competition both in the gas commodity market and the transportation market. The Commission's initiatives were supplemented by the actions of state regulators who too saw the need to begin to open local distribution systems by allowing large industrial and commercial customers to purchase their own gas and transport that gas both on the interstate pipeline and on the LDC's facilities.

As a result of the Commission and state open access and unbundling efforts, the stage was set for more efficient and competitive markets to develop that would reduce overall gas prices to consumers. LDCs began to contract for gas supplies in the production area and separately for transportation service from pipelines. Large industrial customers began to do the same, contracting for interstate pipeline capacity and transportation service on LDCs. Market centers began to develop to facilitate the buying and selling of natural gas and, in 1990, NYMEX established a futures market using the

Henry Hub as the market exchange center.⁸ Shippers and marketers began to use the capacity release mechanism as an alternative to obtaining transportation service from the pipeline, particularly for short-term service.⁹

2. Trends in the Gas Market Today

Today's natural gas market is again in the process of change, and is substantially different operationally and economically from the market in 1993. Upstream and downstream wholesale markets are maturing. As part of this process, both upstream and downstream market centers and gas trading points are increasing, providing shippers with greater gas and capacity choices. The financial marketplace has developed a variety of options and futures contracts that better enable participants to hedge against price risk. Electronic commerce (eCommerce) has grown rapidly providing greater liquidity in commodity markets and with the promise of providing such liquidity in the transportation market as well. The industry is relying more on self-regulation to develop standards for business and electronic processes that create greater efficiency in moving gas across the integrated pipeline grid. There is greater integration between the natural gas and the electric generation market, with gas usage for power generation expected to grow substantially in the near future. Residential unbundling at the state level is underway

⁸NYMEX, Henry Hub Natural Gas, <http://www.nymex.com> (November 17, 1999) (futures contract began in 1990).

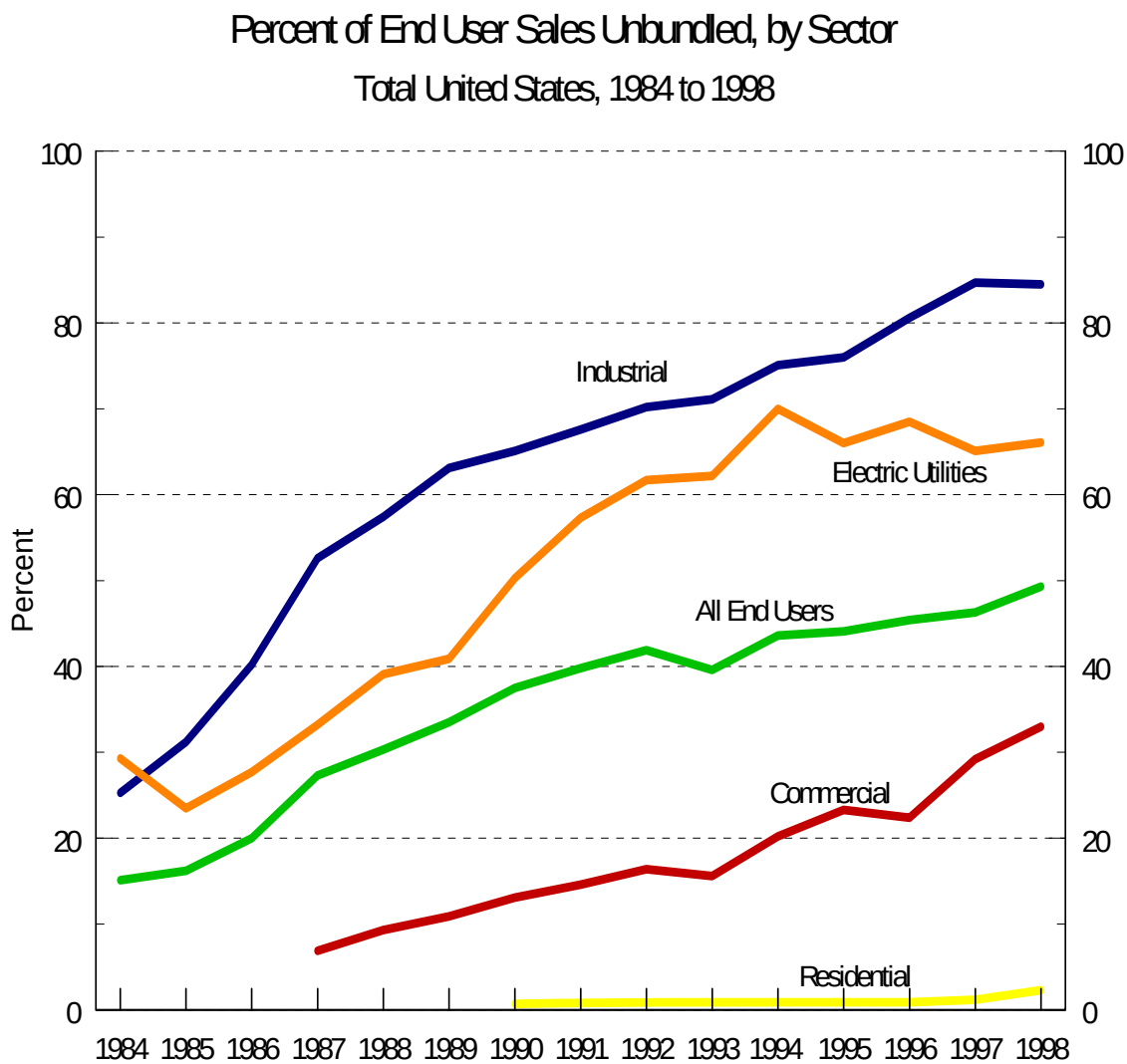
⁹Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 26 (June 1999) (growth of capacity release from 1993 to the present).

which may provide the opportunity for small commercial firms and residential consumers to purchase their gas supplies in a competitive market. These trends are in various stages of development, with the growth of wholesale markets firmly established while residential retail unbundling is still in its infancy. These trends, and the challenges they present the Commission in its regulation of the natural gas industry, are discussed below.

a. Wholesale Markets

The wholesale market, composed of both the natural gas commodity market and the transportation market, has grown with new participants with the unbundling of transportation and sales service at the LDC level. Since 1984, large numbers of industrial customers, electric generators, and end use customers have been buying gas from parties other than the pipelines or LDCs, as shown in Figure 1.¹⁰

¹⁰As of 1998, the percentage of customers unbundled at the retail level were: industrials -- 84.5%, electric utilities -- 66.1%, other end users -- 49.3%, commercial customers -- 33%, residential consumers -- 2.3%. Energy Information Administration, Natural Gas Annual 1998, at 35-37, 39, 41 (Oct.1999).

Figure 1 -- Retail Unbundling by End User Segment

Source: Energy Information Administration, *Natural Gas Annual 1998*, October 1999, pp. 35-37, 39, 41.

Note: The Energy Information Administration believes there may be some double counting in the the number of residential customers for 1998.

While industrial customers consume the largest amount of gas of any sector, the use of gas for electric generation shows the greatest recent growth, estimated for the first 11 months of 1998 at 11% greater than in 1997.¹¹

Since Order No. 636, the industry has witnessed a dramatic growth in the use of marketers to provide gas, arrange transportation, or provide both services to LDCs, industrials, end users, and electric generators. Marketing is still relatively unconcentrated, with the shares of the top 4 marketers actually declining by one-third from 1992-1997.¹² At the same time, marketing sales volume has increased sharply, with the sales volume of the top twenty marketers tripling to 40 trillion cubic feet from 1992 to 1997.¹³ Marketers currently hold over 20% of pipeline firm capacity.¹⁴ Gas customers use marketers in a variety of ways. LDCs, which hold firm transportation on a single pipeline, can use the marketer to obtain and deliver gas to an interconnect point on that pipeline and the LDC can use its firm transportation service to deliver that gas to its citygate delivery point. Other customers, such as industrials, may employ a marketer to

¹¹Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), Natural Gas Issues and Trends 31-33 (1999).

¹²Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 152-153& Figure 55 (June 1999). According to one source, there are 541 electric and gas marketers as of 1998. The Energy Report, June 8, 1998.

¹³Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 152-153& Figure 55 (June 1999).

¹⁴Id. at 222, Table D12.

acquire gas and interstate transportation service to deliver the gas to the industrial's citygate delivery point. Increasingly, marketers are offering additional services to customers such as asset management services where the marketer manages capacity for LDCs as well as price hedging and risk management services, including the provision of financing options.¹⁵

Market centers: In order for producers and marketers to serve LDCs and other customers, active wholesale markets have developed upstream (in production areas) and they are growing in downstream markets as well. Gas customers have the choice of entering into long-term gas contracts to assure supply or price or they can rely upon monthly and daily spot markets to obtain their gas supplies. Customers further have the option of buying gas at upstream market centers in the production area or at market centers in downstream markets. A market center is a point of interconnection between pipelines where traders can exchange gas and shippers can obtain a variety of services, including gas trading, wheeling, parking, loaning, storage, and transfer facilities.¹⁶

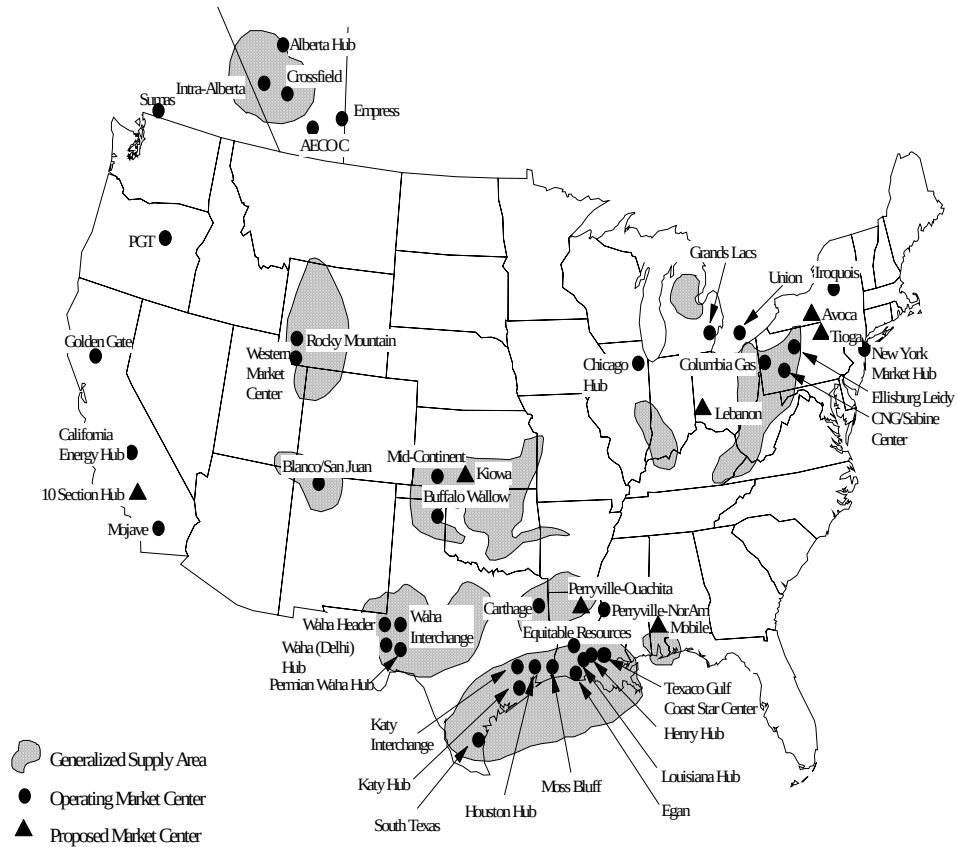
¹⁵See Comments of Dynegy (national marketer of both gas and electricity, asset manager for LDC capacity, owner of interstate pipelines and gathering systems, partner in retail gas ventures); Duke Energy Trading (provides gas and energy-related services); Enron Capital (asset management services, supplying gas for electric loads, price hedging and risk management services, provision of financing options).

¹⁶S. Holmes, The Development of Market Centers and Electronic Trading in Natural Gas Markets 1-2 (June 1999) (Discussion Paper 99-01, Office of Economic Policy, Federal Energy Regulatory Commission) (available from the Commission).

Market centers enhance competition because buyers and sellers of gas have a greater number of alternative pipelines from which to choose in order to obtain and deliver gas supplies. The number of market centers has increased from 5 in 1992 to 38 today with additional market centers being proposed.¹⁷ Although the initial market centers were in the upstream production areas, downstream market centers are now developing. (See Figure 2)¹⁸

¹⁷Id.

¹⁸Id., at Figure 1 and Table 1 (showing market centers in the Midwest, Northeast, and West).

Figure 2 -- Current and Proposed Market Centers as of June 1999

The buying and selling of gas similarly has moved from the production area into downstream markets. Trade publications, for instance, report monthly prices at over 100 locations, including many downstream markets.¹⁹

Financial market: At the same time, an active financial market has developed on the NYMEX to enable wholesale shippers to hedge against future price risks in gas. The NYMEX futures contract has been the fastest growing instrument in its history, and in October 1992, NYMEX began offering options on natural gas futures, giving market participants additional flexibility in managing their market risk.²⁰

Hedging occurs when a seller uses a financial instrument to fix the price at which it will buy or sell a commodity at some future date. By locking in a known price in the future, a buyer in the natural gas market, for example, can protect itself against future increases in the spot market price. Two financial instruments commonly used for hedging are a forward contract and a futures contract.²¹

¹⁹See Henning & Sloan, Analysis of Short-Term Natural Gas Markets, A-2 (Energy and Environmental Analysis, Inc., Nov. 1998).

²⁰NYMEX, Henry Hub Natural Gas, <http://www.nymex.com> (November 17, 1999).

²¹A forward contract is a contract made now for the exchange (sale and purchase) of a physical commodity (or financial instrument) at some future date. For many forward contracts, no price is paid or received at the time the contract is entered into. The exchange contemplated in the forward contract almost always takes place. Forward contracts are usually used as a way to buy or sell the commodity.

A futures contract is a standardized contract to take or make delivery of a commodity (or financial instrument) at some future date at the prevailing price at the time
(continued...)

Transportation market: The growth of downstream markets has affected the transportation market as well. Shippers now have the choice of buying gas in upstream markets and transporting that gas to their downstream delivery points or purchasing gas in downstream markets.²² Although not as well developed as the gas market, a more competitive transportation market also has developed with shippers able to choose between alternative means of acquiring capacity. Shippers can choose either short or long-term services from the pipeline or acquire capacity from other shippers through the capacity release mechanism. As an example of the growth of the capacity release market,

²¹(...continued)

they are entered into. Futures contracts differ from forward contracts in that delivery or receipt of the commodity almost never takes place. Holders of futures contracts get out of their contracts by acquiring opposite contracts for the same commodity and delivery date as their own. For example, a person who purchased a futures contract initially would sell a similar contract to get out of the initial contract prior to its delivery date. This process is known as "offsetting" the initial contract. After completing it, the purchaser is no longer a party to either contract.

When using futures to hedge, a seller or buyer of natural gas takes a position on the futures market that is the opposite of its position in the physical or cash market. The objective is to lock in a price (and consequently a margin) that is acceptable to the hedger. For example, a producer who wants to receive \$2.00 per MMBtu for gas next month would sell a futures contract for \$2.00 to deliver gas in that month. If the price on the cash market and the futures market both drop to \$1.80 for the next month, the producer will obtain only \$1.80 for its gas in the cash market. However, the producer can now close out its futures position by buying a similar contract (offsetting his contract) for \$1.80. Since it originally sold for \$2.00, it earns \$0.20 on its futures position. This, added to the \$1.80 received for its gas, provides the producer with the desired \$2.00 price for its gas.

²²See Gas Daily, September 14, 1999, at 2 (reports on citygate and pooling point prices); Natural Gas Week, November 1, 1999, at 7-8 (spot differentials between market hubs in production and consumption markets).

released capacity for the 12 month period ending March 1997 averaged 20 trillion Btu/day, totaling 7.4 quadrillion Btu for the year, a 22% percent increase over the previous 12 month period and almost double the level for the 12 months ending March 1995.²³ Unlike the commodity market, however, a formal forward or options market for transportation capacity has not developed, although private parties are providing price hedging and risk management services.²⁴

The development of the wholesale gas market is dynamic, reflecting the ever changing supply conditions in the industry. In the past, gas supplies generally flowed north into the mid-west and Northeastern markets. But, with the development of new and increased gas supplies from Canada, gas supplies now flow south and east as well as north. Natural gas supplies from Canada have increased from less than 1 Tcf in 1985 to 3Tcf in 1998, and pipeline expansions would add approximately 3 Bcf per day of capacity to ship gas from Canada to the United States.²⁵ This flow creates additional market centers and trading points, such as the Chicago hub. Pipeline projects are being proposed to pick up gas at the Chicago hub and carry the gas eastward.²⁶ New supplies in the outer

²³Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0618(98), Deliverability on the Interstate Natural Gas Pipeline System 83 (1998).

²⁴See Comment of Enron Capital (providing price hedging and risk management services).

²⁵See Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 12-13 (June 1999).

²⁶See Department of Energy/Energy Information Administration, Pub. No.
(continued...)

continental shelf, the production areas of Wyoming and Montana, and in Nova Scotia also create demand for new pipeline construction that will change the way in which shippers and pipelines do business and can lead to the creation of additional market centers and trading points.²⁷

Changes have already occurred in the way shippers use pipelines because the growth of downstream market and trading centers has enlarged the purchasing options for gas buyers. As a result of market centers, for example, an industrial gas customer no longer needs to hold pipeline capacity upstream at the wellhead or production area. The industrial customer can hold firm capacity on the downstream pipeline that directly connects to its plant (or the LDC serving its plant) and purchase its gas from a marketer at a downstream market center. The marketer makes the arrangements for providing gas at the market center, which could include purchasing gas at the wellhead or an upstream market center in the production area and transporting the gas to the market center or simply purchasing gas from another party at the downstream market center.

The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires

²⁶(...continued)
DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 21 (June 1999).

²⁷Id; If You Build It, Will They Come (1999 Status Report), American Gas Association, Appendix A (summarizing new pipeline construction projects related to gas supplies in the Western Canada sedimentary basin, the deepwater Gulf of Mexico, and the Rocky Mountain states.)

capacity on interconnecting pipelines and can schedule gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points that are not physically connected under a single pipeline management.²⁸

Reliability and price: The changes in the wholesale market have increased efficiency and competition in the natural gas market. For example, NYMEX states "the Commission's actions to date have promoted and produced a short-term gas market that is robust, functioning, efficient, and effective."²⁹ The increase in competition has not come at the expense of reliability, although that was a concern expressed prior to issuance of Order No. 636. For example, the first winter after implementation of Order No. 636, in February 1994, a cold spell hit the Northeast, but the market responded with prices rising to balance supply and demand, with only minor distribution outages well removed from the interstate system. Similarly, the market cleared even during severe demand conditions during the winter of 1996.³⁰ Indeed, competition may improve reliability by enabling the market to adjust to demand conditions quickly without the need to rely on regulatory allocation or curtailment policies to determine who obtains gas.³¹

²⁸Comments of Dynegy and Reliant.

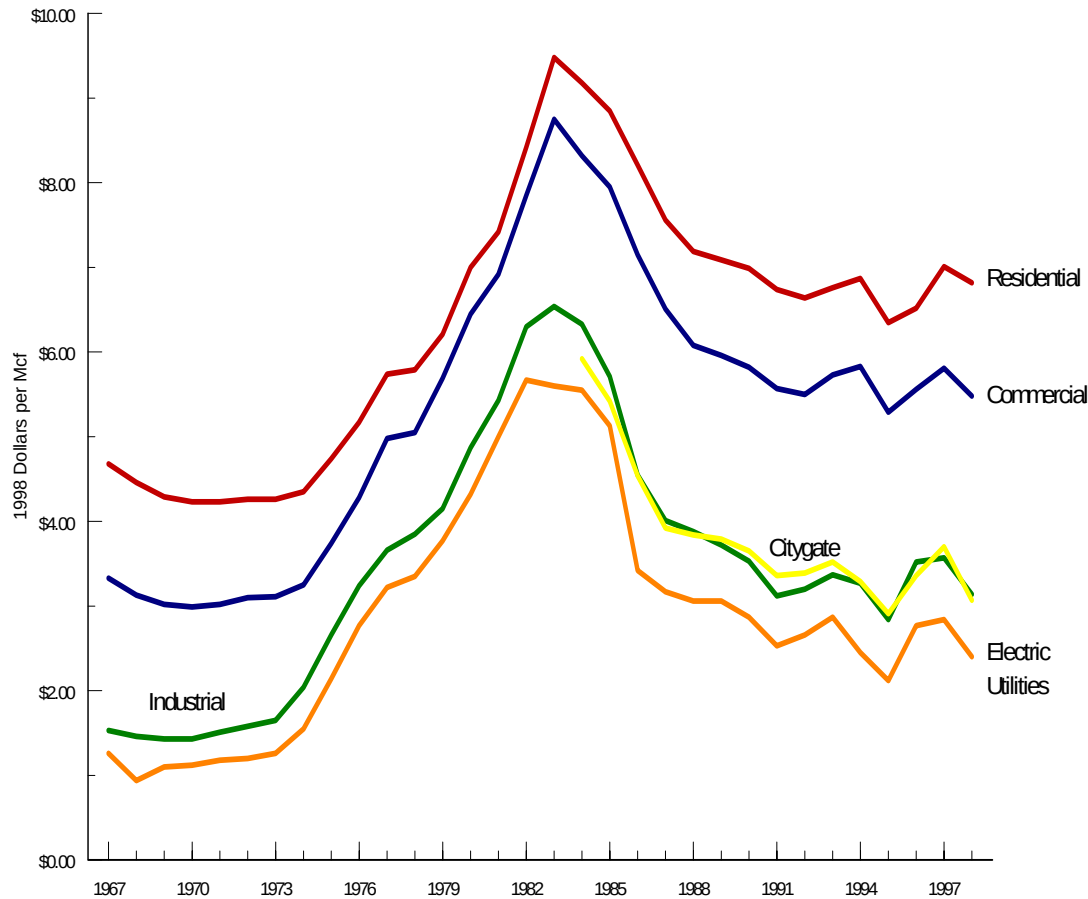
²⁹Comments of NYMEX, at 2.

³⁰See R. O'Neill, C. Whitmore, M. Veloso, The Governance of Energy Displacement Network Oligopolies, Discussion Paper 96-08, at 16-17 Federal Energy Regulatory Commission, Office of Economic Policy, revised May 1997) (copy available from the Federal Energy Regulatory Commission).

³¹Id. (concluding that the unbundled gas market has responded to severe demand
(continued...))

The ultimate test of any regulatory change is the impact of those changes on consumers. By this measure, wellhead decontrol and the Commission's policies have benefitted consumers by lowering the overall price they pay for natural gas. From 1983-1997, the price of natural gas to all industry sectors has fallen significantly from the peaks reached during the periods of gas price regulation and bundled sales. (See Figure 3)

³¹(...continued)
conditions better than the traditionally regulated electric market).

Figure 3 -- Average Prices of Natural Gas by Industry Sector 1967-1998

Sources: Energy Information Administration, *Annual Energy Review*, 1997, and *Natural Gas Annual*, October 1999.

Note: Prices adjusted using GDP Deflator.

eCommerce: The development of the wholesale gas market has been aided by the standardization of pipeline business practices and communication methodologies and the growth of eCommerce. As a result of Commission initiatives, the industry formed a self-governing standards development organization, the Gas Industry Standards Board

(GISB), to develop standards for pipeline business and communication practices that enhance efficiency by better enabling shippers to move gas through markets centers and across interconnected pipelines.³² GISB is a private organization which brings together all segments of the natural gas industry to develop needed standards. Its purpose is to reduce the disparities and inconsistencies in pipeline business and communication practices that have impeded the development of an integrated pipeline grid.

The Commission has encouraged the gas industry to move toward the use of eCommerce to increase efficiency. Beginning in 1993, the Commission established industry working groups to develop a set of electronic standards governing the trading of released capacity on pipeline Electronic Bulletin Boards.³³ Since then, GISB has been developing standards for conducting a wide range of business transactions over the Internet, including scheduling, transmission of flowing gas information, invoicing, and capacity release transactions.³⁴

³²Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587, 61 FR 39053 (Jul. 26, 1996), III FERC Stats. & Regs. Regulations Preambles ¶ 31,038 (Jul. 17, 1996).

³³Standards of Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, 59 FR 516 (Jan. 5, 1994), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,988 (Dec. 23, 1993).

³⁴Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587, 61 FR 39053 (Jul. 26, 1996), III FERC Stats. & Regs. Regulations Preambles ¶ 31,038 (Jul. 17, 1996), Order No. 587-B, 62 FR 5521 (Feb. 6, 1997), III FERC Stats. & Regs. Regulations Preambles ¶ 31,046 (Jan. 30, 1997).

Along with the development of electronic communication between pipelines and shippers, an electronic market has developed to facilitate the buying and selling of natural gas. Electronic trading of natural gas is the furthest along of all energy markets.³⁵ Without electronic trading, shippers have to obtain gas by checking industry publications for a range of gas prices for the previous day, contacting potential gas suppliers using the telephone or fax machines to obtain price quotes to compare, deciding which is the best deal, and consummating the final transaction. Electronic trading creates a more efficient market by expanding the number of buyers and sellers interacting, reducing the time and resources needed to obtain price information and consummate trades, providing anonymity so traders do not have to disclose their market positions, and providing traders with more confidence in the prices they obtain.³⁶ One study estimates that on-line trading of natural gas in 1999 will amount to \$10 billion.³⁷ Many of these electronic transactions

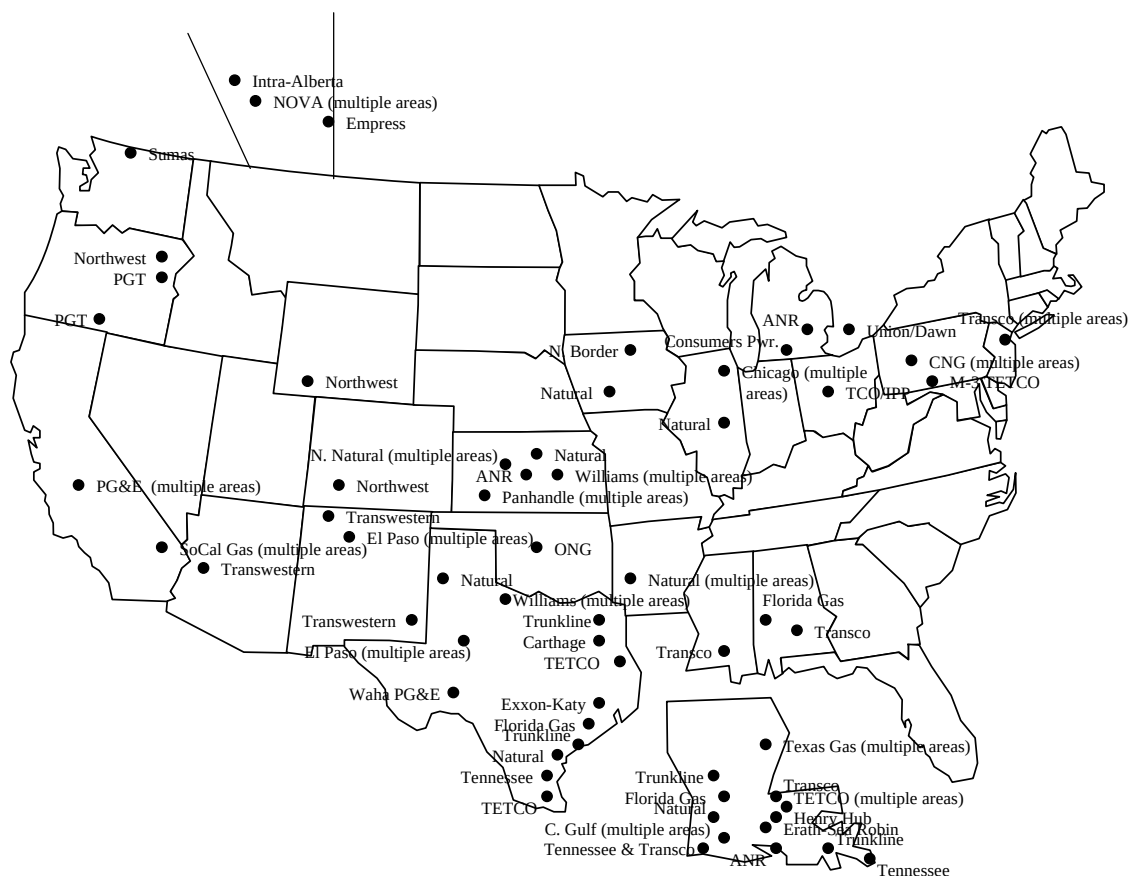
³⁵V. Lief, The Surge of Online Energy, The Forrester Report, 2-3 (Sept. 1999); Comment of Altra; Enermetrix.com, <http://www.enermetrix.com>.

³⁶As one interviewee in the Forrester report explained: "before online trading, if you didn't talk to people all morning -- you'd miss the market. We use it quite a bit and sometimes its the only market." V. Lief, The Surge of Online Energy, The Forrester Report, 2 (Sept. 1999). See Electronic Trading Revolution Not Over, Gas Daily, Vol. 15, No. 224, (Nov. 18, 1998) (electronic trading provides access to hundreds of potential transaction partners and price transparency).

³⁷V. Lief, The Surge of Online Energy, The Forrester Report, 9 (Sept. 1999).

occur at downstream markets. (See Figure 4 showing the electronic gas trading points for Altrade and Natural Gas Exchange).³⁸

Figure 4 -- Altrade and Natural Gas Exchange Trading Points



³⁸The trading points for Altrade were provided courtesy of Ultra. The Natural Gas Exchange trading points are taken from S. Holmes, *The Development of Market Centers and Electronic Trading in Natural Gas Markets 7* (June 1999) (Discussion Paper 99-01, Office of Economic Policy, Federal Energy Regulatory Commission) (available from the Commission).

New electronic trading companies are entering the market³⁹ and eCommerce for gas is expected to grow, reaching 20% of total gas business within two years.⁴⁰ The development of eCommerce can equalize the marketplace between large and small customers. As a customer quoted by Forrester Research states: "Using online services has made us more efficient. We're a small shop so our resources are limited. The system puts us on the same page as the big guys."⁴¹

Implications for Commission regulation: Commodity and transportation markets are closely interdependent in the natural gas business with changes in one market affecting the other. This interdependence has important implications for the Commission's regulation of pipeline transportation. While the growth of a vibrant active wholesale marketplace has enhanced competition, this growth, particularly the development of downstream market centers and trading points, also creates both challenges and opportunities for Commission regulatory policy.

Many LDCs' contracts have expired, or are expiring soon, providing, in many cases, the first opportunity for these LDCs to recontract in the competitive market

³⁹Enron Launches Global Web-based Commodity Trading Site, <http://www4.enron.com/corp/pr/releases/1999/ene/EnronOnline.html> (Internet online trading for wholesale energy and other commodities).

⁴⁰V. Lief, The Surge of Online Energy, The Forrester Report (Sept. 1999).

⁴¹*Id.* at 5. Another customer stated: "Before we just always went to the big guys even though we were not necessarily getting the best prices. Now everyone is using the screens, everyone has the prices, and everyone has the advantage -- making the net one culprit along the path towards reduced margins."

spawned by Order Nos. 436 and 636.⁴² LDCs are considering whether to continue their current firm-to-the-wellhead capacity contracts or whether to reduce their contractual entitlements or to rely more heavily on purchasing gas from producers or gas marketers at downstream market centers or trading points. It is not clear whether marketers will choose to pick up all or some of the firm capacity relinquished by LDCs. Marketers' purchase of firm capacity, for instance, has been increasing, with their holdings increasing by 18% during the 12-months ending July 1, 1998.⁴³ But, unlike LDCs, marketers are not guaranteed passthrough of capacity costs and therefore are likely to subscribe to shorter term contracts than what the LDCs signed in the past.⁴⁴ Marketers, and other transportation customers, also may be less willing than LDCs to sign long-term contracts with Memphis⁴⁵ clauses that permit pipelines to increase prices unilaterally by filing new rate cases.

The renegotiation of contracts, both as to coverage and term, increases the risks for pipelines that may have greater difficulty reselling capacity (capacity turnback).⁴⁶ This

⁴²See Comments of Columbia.

⁴³Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 136 (June 1999).

⁴⁴Id. at 137.

⁴⁵United Gas Pipeline Co. v. Memphis, 358 U.S. 103 (1958).

⁴⁶The Energy Information Agency has estimated the nationwide turnback level at 20% of the long-term contracted capacity as of July 1998, with variations by region. Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), (continued...)

raises issues about how to compensate pipelines for the increased risk as well as the proper way to design rates for customers remaining on the system.⁴⁷

The growing importance of market centers suggests the need for policy development that will continue to foster the development of both upstream and downstream market centers. For instance, some urge that in order to further market center development, pipeline rate zones need to be redrawn to coincide better with market centers, rates need to be reestablished so that upstream capacity costs are not included in downstream rates, and capacity segmentation policies should be enhanced so that shippers can obtain capacity only on portions of a pipeline.⁴⁸ Reliant also suggests that the use of market centers can be encouraged by the creation of virtual pipelines in which one pipeline is able to acquire capacity on another pipeline.

The movement toward eCommerce highlights the need to create greater integration between the allocation system for pipeline and released capacity and the pipeline scheduling system. In addition, the integration of electronic trading for gas and pipeline

⁴⁶(...continued)
Natural Gas Issues and Trends 144 (1999).

⁴⁷The Commission already has been faced with some of these difficulties. See El Paso Natural Gas Company, 83 FERC ¶ 61,286 (1998) (remarketing of turnback capacity); El Paso Natural Gas Company, 79 FERC ¶ 61,028, reh'g denied, 80 FERC ¶ 61,084 (1997), remanded Southern California Edison Company v. FERC, 162 F.3d 116 (D.C. Cir. 1999) (attempt to reach settlement on capacity turnback); Natural Gas Pipeline Company of America, 73 FERC ¶ 61,050, at 61,128-29 (1995)(recovery of turnback capacity costs).

⁴⁸See Comments of Production Area Rate Design Group; Reliant.

capacity would further efficiency by permitting shippers to complete all aspects of a transaction in a single online auction. GISB has recently approved standards for title transfer tracking under which pipelines will track gas transactions between parties at pooling points using the electronic protocols for scheduling gas. Third parties also will be able to consummate gas trades at pooling points and have those trades processed by the pipeline.⁴⁹ Such title transfer services could form the basis for electronic trading that fully integrates gas and capacity trades with the pipelines' scheduling system.

b. Integration of the Gas and Electric Markets

The increasing development of wholesale markets for gas also are affected by the growing synergy between the gas and electric markets. The Commission, in Order No. 888,⁵⁰ and the states have begun to open the electric market to competitive forces in generation, a trend which is having, and is projected to have, a significant effect on gas markets. Gas for power generation is projected to grow 4.5% annually from 1997 through 2020, reaching 9.2 Tcf, a level three times the 1997 level of usage.⁵¹ As a result of this new demand, the gas market is projected to grow from 22 Tcf per year today to 30

⁴⁹Final Actions Regarding Title Transfer Tracking, standard 1.3.64, <http://www.gisb.org/final.htm> (ratified on January 23, 1999).

⁵⁰ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 31,036 (Apr. 24, 1996).

⁵¹Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), Natural Gas Issues and Trends 33 (1999).

Tcf per year by 2010, a 27% increase over current levels.⁵² Distributed power generation located near the end user may provide another vehicle for the use of natural gas, as many of these units are projected to use natural gas as an energy source.⁵³ Gas fired electric generators contend that their use of natural gas as a supply source would be improved by the provision of transportation service that enables them to coordinate the delivery of gas with their need to generate electricity.⁵⁴

The increased integration of gas and electric markets is reflected in the mergers between power generators and pipeline companies as well as the number of marketers that resell both gas and electricity.⁵⁵ Some marketers are operating their own generation plants.⁵⁶ For some customers, the energy markets have converged to a Btu market where the customer can purchase whatever energy source is cheapest at the time.

⁵²Department of Energy/Energy Information Administration, 1999 Annual Energy Outlook (30 Tcf by 2010). See Gas Research Institute, Baseline Projection Data Book, at Page Sum 20 (1998 edition) (30 Tcf by 2015).

⁵³Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), Natural Gas Issues and Trends 33. Distributed power is projected to account for 20 percent of additions to generating capacity, or 35 Gigawatts, over the next two decades. See Distributed Power Coalition of America, <http://www.dpc.org/faq.html> (November 17, 1999) (gas turbines most popular means of generating distributed power).

⁵⁴See Comments of INGAA, Williams Companies, Reliant, Sithe, Sempra Energy, EEI. See also Reliant Energy Gas Transmission Company, 87 FERC ¶ 61,298 (1999) (hourly flexibility service designed to meet needs of power generators).

⁵⁵Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), Natural Gas Issues and Trends 147-67, 231-42 (1999) (discussing the increased trend toward corporate alliances and mergers).

⁵⁶See Comments of Dynegy (owner of power generation facilities).

The pace of mergers and alliances raises questions about the future structure of the industry.⁵⁷ Mergers between pipeline corporations can increase concentration and reduce competition in markets where the merged firms previously competed. Vertical mergers between pipeline companies and gas fired power generators raise concerns about the ability of the integrated firm to injure competition by favoring its vertically integrated affiliate.⁵⁸ The increasing use of asset managers by LDCs⁵⁹ and other shippers to manage their pipeline capacity could result in the concentration of pipeline capacity in a few hands, reducing the competitiveness of the capacity resale market. The potential for increasing affiliation between pipelines and power generators also raises questions about whether changes are needed in the Commission's regulations of pipeline affiliate relationships, which are limited to pipeline marketing affiliates.⁶⁰

c. Residential Retail Markets

The unbundling that already has taken place may be only a harbinger of the future. While unbundling for the larger industrial and end-use customers is at relatively high

⁵⁷See Comment of Dynegy (expressing concern about the integrated corporations using transportation capacity as a marketing lever to obtain business for a generation affiliate).

⁵⁸The Federal Trade Commission entered into a consent decree in one vertical merger between a pipeline and an LDC out of concern about the ability of the LDC to manipulate its confirmation practices to favor its pipeline affiliate. CMS Energy Corp, 64 FR 14725 (Mar. 26, 1999).

⁵⁹See Comments of Dynegy, Enron Capital (providing asset management services).

⁶⁰18 CFR 161 (1999).

level,⁶¹ unbundling for smaller commercial customers and for residential consumers has not taken place to the same extent. The growing focus in the states is on efforts to complete the unbundling process by offering unbundled services to commercial and residential consumers. According to the Energy Information Administration, as of June 1999, eleven states have active unbundling programs or are in the implementation phase, nine states and the District of Columbia have pilot programs or partial unbundling programs (with one state scheduled to begin its pilot program in November 1999), eleven states are considering action on unbundling plans, and eighteen states have taken no action. Consumer acceptance of these programs is mixed.⁶² In Nebraska, 97% of eligible residential consumers have elected to choose their own supplier, while in other states participation of eligible consumers is 2% or less.⁶³

The competitive dynamics of both gas and electric unbundling are generating a movement toward new ways of selling energy products to residential consumers. For instance, eCommerce is beginning to enter the consumer arena with companies offering residential customers one-stop shopping over the Internet for electric and gas service from affiliated companies as well as offering other utility services, such as long-distance

⁶¹See text and notes, *supra*, at Figure 1.

⁶²Department of Energy/Energy Information Administration, http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html (2/2/00) (The eleven states that have active unbundling programs or are in the implementation phase are: New Mexico, New York, West Virginia, Georgia, Maryland, Massachusetts, New Jersey, Ohio, California, Colorado, Pennsylvania).

⁶³*Id.*

telephone and Internet services.⁶⁴ There are business alliances between gas distributors and traditional consumer retailers to sell both gas and electricity to residential and commercial customers.⁶⁵

Whether and how far residential unbundling will progress is one of the major unknowns in the current market and, even if it does occur, the implications of such a change are hard to predict. To the extent full residential unbundling occurs, LDCs would exit the interstate transportation function entirely, being replaced by producers and marketers, neither of which have the ability automatically to pass costs on to consumers. In the short-run, retail unbundling has created more uncertainty about contract duration. LDCs, which may unbundle their transportation service from gas sales, are unwilling to enter into long-term contracts for interstate capacity until the structure of unbundling in their state is determined.⁶⁶ Similarly, the marketers that may replace the LDCs are not in position yet to determine whether to sign long-term capacity contracts and for what quantities. In the long-run, however, the effect of unbundling on firm capacity holdings

⁶⁴See PowerTrust.com, <http://www.powertrust.com>; Essential.com, <http://essential.com>.

⁶⁵Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560(98), Natural Gas Issues and Trends 231 (1999) (alliance between Columbia Energy and Amway Corporation for door-to-door marketing of gas and electricity); <http://www.amway.com/infocenter/pressrel/pressrel49.asp> (November 18, 1999) (program expands from Georgia to Ohio); Ga. Marketers Unveil Deals, Gas Daily, November 16, 1999, at 5 (alliance between SCANA Energy and Krogers grocery stores to market natural gas services at kiosks).

⁶⁶Comments of AGA I, PSE&G, Columbia.

is less clear. Marketers still may choose to subscribe to firm capacity in order to guarantee service. In some states, regulators, concerned with ensuring reliable deliveries, are considering whether LDCs should be required to be the suppliers of last resort in case marketers default or whether marketers will be required to hold primary firm capacity as a prerequisite to participation in unbundling programs.⁶⁷

B. The Commission's Response to the Transition in the Market

The Commission's response to the changes taking place in the market must be informed by its regulatory responsibilities and objectives.

1. The Commission's Regulatory Objectives

The Commission has the regulatory responsibility under the Natural Gas Act to ensure that pipeline rates and services are just and reasonable and not unduly discriminatory.⁶⁸ Just and reasonable rates and services need to be designed to achieve two principal objectives. They should promote competitive and efficient markets,⁶⁹ while mitigating market power and preventing undue discrimination, especially for the

⁶⁷See Comment of ConEd.

⁶⁸Natural Gas Act, § 4, 15 U.S.C. 717(d).

⁶⁹Under the Wellhead Decontrol Act, for example, the Commission is obliged to structure its regulatory framework to "improve [the] competitive structure [of the natural gas industry] in order to maximize the benefits of [Wellhead] decontrol. Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101-29, 101st Cong., 1st Sess., at 6 (1989); Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,939, at 30,932 (Apr. 8, 1992).

Commission's "prime constituency, captive customers vulnerable to pipelines' market power".⁷⁰ In short, the Commission's regulatory policy must seek to reconcile the objectives of fostering an efficient market that provides good alternatives to as many shippers as possible while at the same time creating a regulatory framework that is fair and protects captive customers without good alternatives.

In order to achieve these basic objectives, there are several subsidiary ends that regulatory policy should strive to achieve. Regulatory policies should seek to expand customers' alternatives and choices, which will in turn dissipate the ability to exercise market power. These policies need to create efficient market mechanisms that will enhance competitive options. They also should ensure that reliable information is available to better enable shippers to make informed choices in the market and to permit shippers and the Commission to monitor for undue discrimination and the exercise of market power. At the same time, to the extent adequate competition does not exist, regulation needs to mitigate residual market power and protect captive customers. In addition, regulation needs to be fair and administratively efficient, so that the regulation itself does not impose undue or unnecessary costs on the industry.

2. The Commission's Response to the Changing Gas Market

⁷⁰United Distribution Companies v. FERC, 88 F.3d 1105, 1123 (D.C. Cir. 1996). See Maryland People's Counsel v. FERC, 761 F.2d 780, 781 (D.C. Cir. 1985); FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988).

Since Order No. 436, the Commission has been reexamining its rate and regulatory policies to adapt those policies to changes in the competitive market and to ensure that its regulatory policies promote its goals and objectives.⁷¹ In analyzing the interrelation between the Commission's current regulatory policy and the changing natural gas market, the Commission has concluded that its current regulatory framework does not meet the current needs of the market. In some situations, the current regulatory model inhibits the ability of the market to respond efficiently to demand conditions, limits shippers' capacity choices, and may not provide the lowest rates to captive customers.

The Commission is taking two steps to better achieve its regulatory objectives. First, in this rule, the Commission is taking an interim step to revise aspects of its current regulatory model to improve competition and efficiency, without making fundamental changes to that model. Second, the Commission is beginning an effort, outside of this proceeding, to examine more fundamental changes to its regulatory model.

a. The Changes Adopted in this Rule

The changes adopted in this rule are designed to improve the efficiency of the market and increase competition while continuing cost-of-service regulation to protect against the exercise of market power by pipelines. These changes involve modifications

⁷¹See Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. Regulations Preambles [1982-1985] ¶ 30,665, at 31,534 (Oct. 9., 1985); 18 CFR 284.7(c); Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 (1989) (requiring that rate methodologies must be designed to improve allocative and productivity efficiency).

to the Commission's ratesetting policies to enable rates to better reflect market demand and to reduce the rate burden on captive customers, improvements to the Commission's regulation of the pipeline grid to increase competition, and revisions to the Commission's reporting requirements.

With respect to rates, the Commission is waiving the price ceiling for short-term capacity release transactions for a period of two years. This change is intended to improve shipper options and market efficiency during peak periods, when an efficient and effective market is most needed. During peak periods, the maximum rate cap on capacity release transactions inhibits the creation of an effective transportation market by preventing capacity from going to those who value it the most. The elimination of the rate ceiling will eliminate this inefficiency and enhance shipper options in the short-term market. To protect against the potential exercise of market power, the Commission is maintaining cost-of-service regulation of the pipelines as well as improving efficiency and competition across the pipeline grid along with enhanced reporting requirements that will provide more information to the market and permit better detection of market power abuses. While the changes in the natural gas industry support the removal of the rate ceiling, the Commission recognizes that this is a significant change in policy. The limited term waiver is intended to provide an opportunity for Commission review of this policy after the industry and the Commission have experience over two winters, which should be sufficient to analyze the results of this change.

The Commission further is revising its regulatory policies regarding rates for pipeline services to enable pipelines to file for peak/off-peak and term differentiated rates if a pipeline finds that such rates better reflect the demands and risks it faces. Such rates, however, would still have to satisfy the revenue and cost constraints of the traditional regulatory model. To help facilitate the trend toward eCommerce, the Commission is encouraging both pipelines and third-parties to develop voluntary auctions and is willing to consider waivers of some of its regulatory requirements that may impede the development of capacity auctions.

The removal of the rate ceiling for short-term capacity release transactions and the ability of pipelines to institute peak/off-peak and term-differentiated rates should help to reduce the cost of capacity to captive customers. The captive customers currently pay maximum rates for transportation capacity during peak and off-peak periods to support the pipeline system, while short-term shippers benefit by paying lower market prices during off-peak periods reflecting the reduced demand on the system, but do not face the market rate for capacity during peak periods as a result of the rate ceiling. The changes in ratemaking policies adopted in this rule will help to reduce the revenue responsibility of captive customers by placing on short-term shippers more of the burden of paying for peak period usage of the system. The Commission's objective is for the reduction in captive customers' revenue responsibility to be achieved through a combination of increased capacity release revenues, as well as revenue credits, reduced discount

adjustments, and lower long-term rates on pipelines instituting peak/off-peak or term-differentiated rates.

To create greater substitutability between different forms of capacity and enhance competition across the pipeline grid, the Commission is revising its regulations regarding scheduling, segmentation and flexible point rights, penalties, and reporting requirements. The Commission is revising pipeline scheduling procedures so that capacity release transactions can be better coordinated with the nomination process. The Commission is further requiring pipelines to permit shippers to segment capacity wherever feasible, which increases potential capacity alternatives and helps to facilitate the development and use of market centers. The Commission's revision to penalty procedures will create appropriate incentives and will provide shippers with increased information and additional services to help them avoid the incurrence of penalties. The changes to the Commission's reporting requirements will enhance the reliability of information about capacity availability and price that shippers need to make informed decisions in a competitive market as well as improve shippers' and the Commission's ability to monitor marketplace behavior to detect, and remedy anticompetitive behavior.

The Commission is clarifying its policies regarding two aspects of pipeline service: the right of first refusal and negotiated rates and terms and conditions of service. The Commission is narrowing the right of first refusal (ROFR) in its regulations so that this right interferes as little as possible with the efficient allocation of pipeline capacity, while protecting captive customers against the loss of transportation service. The

Commission is clarifying the operation of its policies regarding negotiated rates and negotiated terms and conditions of service in light of its decision in this rule not to adopt regulations providing pre-approval for pipelines to negotiate terms and conditions of service.

b. Process for Future Regulatory Policy Development

All of the changes in this rule remain within the Commission's current regulatory framework. As discussed earlier, many of the trends in the current market raise questions about a number of Commission regulatory policies, including the effectiveness of the current regulatory model in light of changes to long-term contracts, the effect of regulatory policies on market centers, the need to improve the effectiveness of eCommerce, and the regulation of pipeline affiliates not covered by the current affiliate regulations. It is not yet clear in what direction these trends will lead the market. The changes adopted in this rule are designed to improve the efficiency of the market and to facilitate its development, primarily toward the open and competitive marketplace that current conditions appear to support. Whether more fundamental changes are needed will depend on future market developments and especially how the industry responds to the changes adopted in this rule.

In the Notice of Proposed Rulemaking (NOPR)⁷² and Notice of Inquiry (NOI),⁷³ the Commission sought comment on a variety of fundamental changes to its current regulatory methods to respond to issues raised by the changes in the gas market. In the NOPR, for example, the Commission sought comment on whether mandatory auctions should be used to allocate pipeline capacity and whether pipelines should receive pre-approval for negotiation of the terms and conditions of service with individual shippers. In the NOI, the Commission inquired as to whether fundamental changes in the cost-of-service rate methodology, such as indexing and incentive and performance based rates, should be implemented, whether market based rates are appropriate for turned back capacity, whether a periodic review of pipeline rates should be implemented, whether to revise the straight-fixed-variable rate design requirement, and whether options other than cost-based ratemaking would be more efficient.

Some commenters contend the Commission should make fundamental changes in its regulatory model to accommodate the changes in the market, maintaining that such changes would be consistent with the Commission's responsibilities under the Natural Gas Act. AGA and Williams, for instance, envision a market that is moving toward a structure divided between two classes of pipeline shippers: one class comprised of those

⁷²Regulation of Short-Term Natural Gas Transportation Services, Notice of Proposed Rulemaking, 63 FR 42982 (Aug. 11, 1998), FERC Stats. & Regs. Proposed Regulations [1988-1998] ¶ 32,533 (July 29, 1998).

⁷³Regulation of Interstate Natural Gas Transportation Services, Notice of Inquiry, 63 FR 42973, IV FERC Stats. & Regs. Notices ¶ 35,533 (July 29, 1998).

customers with sufficient alternatives and options which insulate them from the exercise of market power by the pipelines; the other class comprised of those customers who are captive and have limited choices. As AGA states:

some LDCs are captive to pipelines' market power because they are tied to capacity contracts for many more years or because pipeline capacity is constrained into their region.... Other LDCs are not subject to abuse of market power by pipelines because they have been able to renegotiate their capacity contracts to better reflect their current and anticipated need for capacity and because capacity is not constrained into the region."⁷⁴

AGA proposes that the Commission institute two tracks for regulating pipeline transportation service, each available for any shipper to choose. One track would be for cost-based regulated tariff service and the other track for market-responsive negotiated services. The Williams Companies similarly assert that pipelines need to be able to respond to the needs of new customers, like gas fired power generators, by offering market responsive rates and contracts, while still providing cost-based rates as protections for all shippers.

Reliant contends that the development of greater competition in certain areas should lead the Commission to place greater reliance on the use of market forces to establish rates. It contends, for example, that market-based rates should be permitted for pipelines in producing regions where interstate pipelines compete with intrastate

⁷⁴AGA II, at 5.

pipelines, when a pipeline is unable to sell turned back capacity, and where customers can solicit bids for services from more than one pipeline.

A number of parties support the use of auctions as creating more efficient and fairer methods of allocating capacity,⁷⁵ although many other parties are concerned about whether auctions can be designed efficiently and the ability to coordinate gas and capacity purchases in an auction limited to pipeline capacity.⁷⁶ INGAA is concerned that auctions would lower capacity prices which would threaten pipeline revenue recovery, and AGA is concerned about similar impacts on the value of released capacity.

Amoco and NGSA recommend significant changes in current regulatory policy through the adoption of an incentivized cost-of-service of service regulatory model to replace existing cost-of-service procedures. Others support periodic rate reviews or other methods of readjusting pipeline rates.⁷⁷ The Customer Coalition argues that the need to review these long-term issues requires that the Commission consider changes through a new NOPR, additional comments, or further technical conferences.

After reviewing the comments, and the current state of the industry, the Commission has determined that (1) it must approach its regulatory policymaking more strategically to determine whether it needs to examine and begin developing fundamentally new regulatory methods in anticipation of changing market conditions and

⁷⁵Comments of Amoco, Altra, Sithe, Southern Company Energy Marketing.

⁷⁶E.g., Comment of Dynegy.

⁷⁷Comments and Supplemental Comments of the Customer Coalition.

(2) it must monitor market conditions on an ongoing basis to ensure that its decisions do not inhibit competition or foster inefficiency. In these proceedings, the Commission has studied improvements to its regulatory policies that would comport with current developments in the market. It must now ask whether it is effective in this dynamic environment to engage in generic policymaking without a deeper understanding of which possible regulatory model best achieves the Commission's regulatory objectives within the changing structure of the natural gas market and energy markets generally. The Commission, therefore, will be instituting a new process to undertake a continuing examination of the market and the relationship of its rules to the market. This examination will involve questions of rate design and risk allocation in light of changes to long-term contracting policies, improving market centers, creating greater integration of capacity allocation and scheduling processes with the growing trend toward eCommerce, and reexamining the methods for setting and reviewing pipeline rates.

In a nutshell, the Commission still largely applies a coherent "model" of regulation designed for traditional regulated monopolies. Its ratemaking tenets were not fundamentally questioned even as Order Nos. 436 and 636 were adopted. However, the current market may in fact call into question the basic underpinnings of this model and require the Commission to examine the legitimacy of alternative models. Some commenters suggest, for example, that the market is moving toward a dual market structure in which some customers want to negotiate with the pipelines, while others are still captive and need protection against the exercise of market power and undue

discrimination. If that is the case, such a trend raises significant questions about the nature of the Commission's regulatory model. Designing a regulatory framework to accommodate such a trend, if that is the direction of the industry, would involve issues such as whether to permit negotiated terms and conditions of service, whether to allow market-based pricing for pipeline services (both long and short term), whether and how to support pipeline revenue requirements, and whether to change rate designs or the ratemaking process itself.

The Commission's current regulatory model is premised on the assumption that regulation of all pipeline services is necessary and that pipeline rates should be set so that the pipeline is given a reasonable opportunity to recover its prudently incurred costs. But this model would need to be changed to accommodate a two-track model of regulation in which non-captive customers would face market priced services and service flexibility and captive customers would be able to obtain service at regulated rates to protect against the exercise of market power.

A two-track regulatory model would require development of new regulatory methods developed for both the non-captive and captive customers. Customers opting for negotiated service should be subject to the risk of that choice and not be able to choose to negotiate only when it benefits them. New methods would be needed for determining just and reasonable rates and services to protect captive customers.

Captive customers should not be forced to pay for pipeline losses or additional risks in the unregulated portion of their businesses. Indeed, such an outcome may be

difficult to square with the Commission's mandate under the NGA. If pipelines are given the upside potential inherent in lifting regulatory controls over prices and services, it is questionable whether they should have their revenues supported by a ratemaking regime that also guarantees the recovery of all "prudently incurred" costs.⁷⁸ Under a two-track regulatory model, therefore, the rates for captive customers would likely need to be established separate from the revenues from the pipelines' market-based services. One possibility would be to establish captive customer rates based on the proportion of pipeline capacity used by the captive and non-captive customers rather than as is done today on throughput and contract demand. It also might be necessary to change from rates based on a pipeline's individual cost-of-service to rates developed more on average industry costs. In addition, quality of service would need to factor into rate design so that pipelines would have an incentive to continue to improve the quality of service for captive customers.

The industry indeed may be headed in a direction that would make a two-track regulatory model appropriate. If so, these are the kinds of issues with which the Commission would need to grapple. It is not clear, however, whether this is in fact the industry's direction or whether a two-track regulatory model would be the best regulatory model to use. The market's development may reveal that other regulatory models are

⁷⁸Williams, for instance, recognizes that if pipelines are to be given the same potential as competitive firms to earn greater returns through market opportunities, they need to be subject to the risks of market failure just as are unregulated firms.

more desirable. It is possible that a sound regulatory approach could fall anywhere on a spectrum, from traditional utility regulation to a lighter-handed, highly market-oriented focus. Where Commission regulation should fall on that spectrum will depend on the developments in the market and the specific measures that would promote efficiency and protect captive customers at any moment in time. Simply because the industry is in transition today and these choices are therefore difficult, does not mean that the larger questions, of how to adapt the Commission's regulatory approach to changing conditions and how to move policy toward identifiable goals or models, are to be avoided.

The Commission, therefore, is still considering whether to move forward on various proposals for changes in its current regulatory framework, including the use of negotiated terms and conditions of service, changes to SFV rate design, whether to permit discount adjustments, whether to adopt rate reviews or refreshers, and whether to permit more market-based rates. But these issues are interrelated in many respects and cannot be considered separately. Rather, they must be considered within the overall context of the regulatory model that is most appropriate for the current conditions in the market and its likely future direction.

In order to better address these interrelated issues, the Commission has determined to institute a new process outside of this proceeding that will undertake a more systematic approach to evaluating the direction of future natural gas regulation than was possible in this proceeding. This process will be a flexible one and will involve Commission monitoring of the market, dialog between various industry segments, as well as

participation by Commission staff in industry conferences or the establishment of new Commission docketed proceedings if needed.

Any such systematic approach to continuous improvement must do two things. First, it should not contribute greater uncertainty to commercial transactions. The Commission, therefore, needs to collaborate with the pipeline industry and its customers to advance market efficiency on a consensus basis where possible. Second, it should be based on current information. Therefore, the Commission needs to gather and analyze data on an ongoing basis to ensure that its decisions, even in individual cases, reflect the current state of the market. In order to address the comprehensive regulatory issues raised by the changing gas market, the Commission is directing its staff to develop the appropriate market monitoring capability and to begin engaging in a continuing dialog with the industry about potential regulatory improvements.

Through monitoring, the Commission staff will seek to evaluate the structure, conduct, and performance of the industry. For example, Commission staff is directed to look at issues relating to capacity availability during periods of peak and nonpeak demand, the concentration of capacity holdings during peak and nonpeak periods, and the rates charged for service.

This analysis should seek to identify markets where light-handed regulation may be appropriate, as well as those markets in which competitive constraints still exist and the reasons for such constraints. This will allow an assessment of the need for negotiated terms and conditions of service. Such monitoring also will include examination of the

industry's response to the changes in this rule to see the effects of these developments on the market. In this regard, the revised reporting requirements adopted in this rule will permit the Commission to examine how capacity prices respond to the lifting of the price ceiling on short-term capacity release transactions and how delivered prices and capacity prices track each other.

The staff should also monitor pipeline rates and operating and maintenance expenditures to see how well pipelines are performing both as an industry and individually compared to the rest of the industry. Such measures should provide a better measure of pipeline performance than relying on earnings or profitability based on historic investment in plant and equipment. In this regard, the staff should examine whether to change the annual reporting forms filed by pipelines to reduce the burden of supplying unnecessary information, while focusing the reports on data that will provide for a better evaluation of pipeline performance and efficiency. As part of this review, staff should consider whether performance based ratemaking should be pursued as a means to establish rates that appropriately reimburse pipelines for efficiency gains while passing on some of those gains to ratepayers through reduced rates.

In addition, the Commission will be looking at the development of the market in a number of areas, including residential unbundling, evolution of downstream gas markets, the development of eCommerce and auctions, mergers and changes in market structure, affiliate relationships and conduct, the effect of penalties on the market, and long-term investments.

But monitoring, by itself, is not sufficient to develop a full picture of the trends in the industry. It is important for all segments of the industry to engage in a dialog to consider how industry changes do or should affect Commission regulatory policy. Such a dialog will enable the Commission and state regulators to achieve a better understanding of industry trends and regulatory changes that better meet the changing character of the industry. Also, constructive dialog between all the industry segments such as was held under the auspices of the Natural Gas Council will be needed if the industry is to grow to the levels some project. This kind of industry dialog can occur independently of government regulators or it can begin initially with regularly scheduled Commission staff conferences with the industry and market participants. The frequency of these conferences and the nature of any reports or recommendations to the Commission can be determined by the participants themselves.

Some of the topics that need to be considered are:

- whether regulatory changes would further facilitate upstream and downstream market centers, trading areas, and greater gas liquidity;
- whether changes are needed in gas transportation policies to accommodate the increasing convergence of energy markets;
- whether the Commission should seek to create greater standardization in terms and conditions of service across the grid;
- whether regulatory policy with respect to pipeline affiliates and nonaffiliates, as well as asset managers and agents, should be revised to reflect the changing nature of the gas market;
- whether auctions should be developed to coordinate the allocation and scheduling of capacity and the purchase and sale of gas;

- whether rate design policies need to be changed to establish incentives for pipelines to enhance quality and efficiency and reward pipelines appropriately;
- whether the Commission should fundamentally reform its current regulatory model, moving to a two track model or to performance based ratemaking; and
- whether adjustments to reporting requirements beyond those adopted in this rule are needed to better reflect pipeline performance and efficiency.

Examination of these topics could show that changes in certain areas would be inconsistent with changes in other areas, while other changes would complement each other. Whether discussion of these topics ultimately leads to regulatory changes, and what those changes might be, will depend on the outcome of the dialog and developments in the market. The objective is to establish, as routine, an industry-wide dialog with the Commission, through its staff, to determine whether changes are needed in Commission policy and regulation to achieve the Commission's regulatory objectives.

To begin this process, staff will be scheduling technical conferences over the course of the year to discuss issues relating to: whether changes are needed to facilitate the development of upstream and downstream market centers and trading areas, including rate design changes; whether changes are needed to accommodate the convergence of electric and gas markets; whether the Commission should seek to create greater standardization of services and penalty provisions; and whether there need to be revisions to regulations relating to pipeline affiliates.

In the sections that follow, the Commission discusses the changes in its regulations and policies that are being adopted in this order.

II. ADJUSTMENTS TO RATE POLICIES TO IMPROVE EFFICIENCY AND PROTECT AGAINST THE EXERCISE OF MARKET POWER

The Commission's objective in designing rates is to establish a ratesetting framework that increases efficiency in the marketplace, while protecting against the potential exercise of market power. No regulated rate can perfectly emulate the prices found in a competitive marketplace nor protect perfectly against the exercise of market power. This is particularly true when the regulated firm is a natural monopoly⁷⁹ where the competitive price would be insufficient to permit the firm to recover its costs.⁸⁰ Thus, price regulation often permits some exercise of market power and involves tradeoffs between pricing efficiency and the regulatory control over market power. On balance, the Commission finds that the changes to regulation made in this rule -- removing the rate

⁷⁹See *United Distribution Companies v. FERC*, 88 F.3d 1105, 1122 & n.4 (D.C. Cir. 1996) (pipelines are treated as natural monopolies with enormous economies of scale producing declining average costs).

⁸⁰The competitive price is the single price at which the marginal cost curve intersects the demand curve. Due to declining average costs at the point where demand intersects marginal cost (the competitive price), a natural monopoly charging what would be the competitive price for capacity would not cover its total investment. This creates difficult questions of devising an efficient price structure. See Comment of El Paso Energy, Appendix A, at 15 (no way to ensure revenue adequacy for pipelines without deviating in some way from short-run optimal prices); 1 A. Kahn, *The Economics of Regulation*, 130 (1970) (in decreasing cost cases, price at marginal cost insufficient to cover total costs); R. Posner, *Economic Analysis of the Law*, § 12.1, 251-254 (2d ed. 1977) (difficulty of devising an efficient price structure for natural monopolies).

ceiling from capacity release transactions, permitting pipelines to file for peak/off-peak and term differentiated rates, plus the improvements to scheduling, segmentation, penalties, and reporting requirements -- will enhance marketplace efficiency and competition, protect captive customers, and set prices for short-term transactions that reflect demand during peak periods, while not jeopardizing protections against the exercise of market power

In this Part, the Commission discusses the changes in rate policies for capacity release transactions as well as for pipeline services. The first section discusses generally the inefficiencies created by the current regulatory method and how the removal of the rate ceiling for short-term capacity release transactions will create a more efficient and competitive marketplace. That is followed by discussion of changes in policy with respect to pipeline service, i.e., peak/off-peak and term differentiated rates. Finally, the use of voluntary auctions as a means of pricing short-term services is discussed.

A. Removal of the Rate Ceiling for Short-Term Capacity Release Transactions

During peak demand periods, when capacity is at a premium, the need to provide shippers with the greatest number of potential options and the most efficient competitive marketplace is crucial. Shippers that most need capacity during periods of scarce supply need a market that can efficiently respond to their demands and provide the capacity they need. The Commission's regulatory framework also needs to protect captive customers and fairly apportion revenue responsibility between captive customers with limited alternatives and short-term shippers with greater options. At the same time, the

Commission's regulatory mechanism needs to provide all shippers with as much regulatory protection against the exercise of market power as possible. The removal of the rate ceiling for capacity release transactions with continued cost-of-service regulation of pipeline services better satisfies these objectives than continuation of the current uniform maximum rate ceiling for capacity release transactions.

This section first examines the inefficiencies engendered by the current uniform maximum rate ceiling; second, it summarizes the options put forward in the NOPR and comments for dealing with these inefficiencies; third, it discusses how the removal of the rate ceiling for capacity release transactions provides for more efficient markets and protects captive customers, while maintaining cost-based regulation of pipeline services as a protection against market power; and fourth, it addresses the comments on the legal and policy basis for these regulatory changes.

1. Current Regulatory Framework

- a. Description of the Current Regulatory Framework

Under section 4 of the NGA, rates are established by the pipeline filing for rate changes. The rates thus established continue in effect until the pipeline makes a subsequent rate case filing or the Commission takes action under section 5 of the NGA and determines that the existing rates are not just and reasonable.

The Commission currently develops a maximum annual transportation rate for each pipeline that, when applied to the pipeline's contract demand and throughput levels, will enable the pipeline to recover its annual cost-of-service revenue requirement. When

the Commission sought to develop a maximum rate for monthly or daily interruptible or short-term firm transactions, it simply took the yearly maximum rate and divided by 12 or 365, respectively.

The principal reason for limiting pipeline rates to a level that would permit recovery of the pipeline's annual revenue requirement is to limit the ability of the pipelines to exercise market power, so that the pipeline does not charge excessive rates. Without rate regulation, pipelines would have the economic incentive to exercise market power by withholding capacity (including not building new capacity) in order to raise rates and earn greater revenue by creating scarcity. Because pipeline rates are regulated, however, there is little incentive for a pipeline to withhold capacity, because even if it creates scarcity, it cannot charge rates above those set by its cost-of-service. Since pipelines cannot increase revenues by withholding capacity, rate regulation has the added benefit of providing pipelines with a financial incentive to build new capacity when demand exists. The investment in new capacity increases a pipeline's revenue because the new investment increases the pipeline's rate base on which the pipeline earns a rate of return.⁸¹ Thus, annual rate regulation protects against the pipeline's exercise of market power by limiting the incentive of a monopolist to withhold capacity in order to increase

⁸¹For instance, if a pipeline has a current rate base of \$1 million and an approved overall rate of return of 10%, the pipeline earns \$100,000. However, if demand justifies an expansion of the pipeline's system at a cost of \$500,000, at the same rate of return, the pipeline would earn \$150,000, thus creating a financial incentive to expand the pipeline's system whenever demand permits.

price as well as creates a positive incentive for a pipeline to add capacity when needed by the market.

The protection provided by rate regulation, however, is related solely to the pipeline's annual revenue requirement, not to the monthly or daily rate charged by the pipelines for capacity. The monthly or daily rate does not approximate the rates that would be charged in a competitive market, since such short-term rates do not seek to match price with the demands placed on the system. Indeed, the current regulatory model permits pipelines to exercise market power by selectively discounting their daily, monthly, and sometimes yearly rates (in effect price discriminating) at rates less than the maximum rate. Selective discounting helps the pipeline generate more annual revenue than it could receive by charging a single fixed price. The justification for permitting selective discounting is that the additional revenue benefits those shippers paying maximum cost-of-service rates by reducing, in the pipeline's rate case, the amount of the costs that otherwise would be recovered through the rates paid by those captive customers.⁸²

In Order No. 636, the Commission applied the daily maximum rate to capacity release transactions. At that time, the Commission declined requests to remove the price

⁸²Associated Gas Distributors v. FERC, 824 F.2d 981, 1010-1012 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988); Comment of El Paso Energy, Appendix A (price discrimination below the existing maximum rate helps pipelines recover cost-of-service); 1 A. Kahn, The Economics of Regulation 131-33 (1970) (price discrimination one solution to problems of natural monopoly and declining costs).

cap for released capacity on the ground that the release market had not been shown to be sufficiently competitive.⁸³ When Order No. 636 was issued, most gas transactions occurred at the wellhead or upstream market centers.

Since Order No. 636, the gas market has continued to evolve with the development of spot markets in downstream markets at which customers without firm capacity or without sufficient capacity to cover their needs purchase delivered gas on a short-term basis. The price for these transactions reflects both the cost of gas and the value of transportation to the delivered market. Figure 5 shows the variances between weekly average gas prices in various upstream and downstream markets as well as the implicit price for transportation between each of the markets. The prices at each designated market represent the price of gas and the figures in parenthesis between markets represent the implicit value of transporting gas from the lower priced to the higher priced market. The prices in downstream markets, such as the Chicago Citygate, represent the price paid by shippers purchasing delivered gas at that market.⁸⁴ The implicit price for transportation represents the most any shipper purchasing delivered gas at a downstream market would pay to move gas from the lower priced market to the

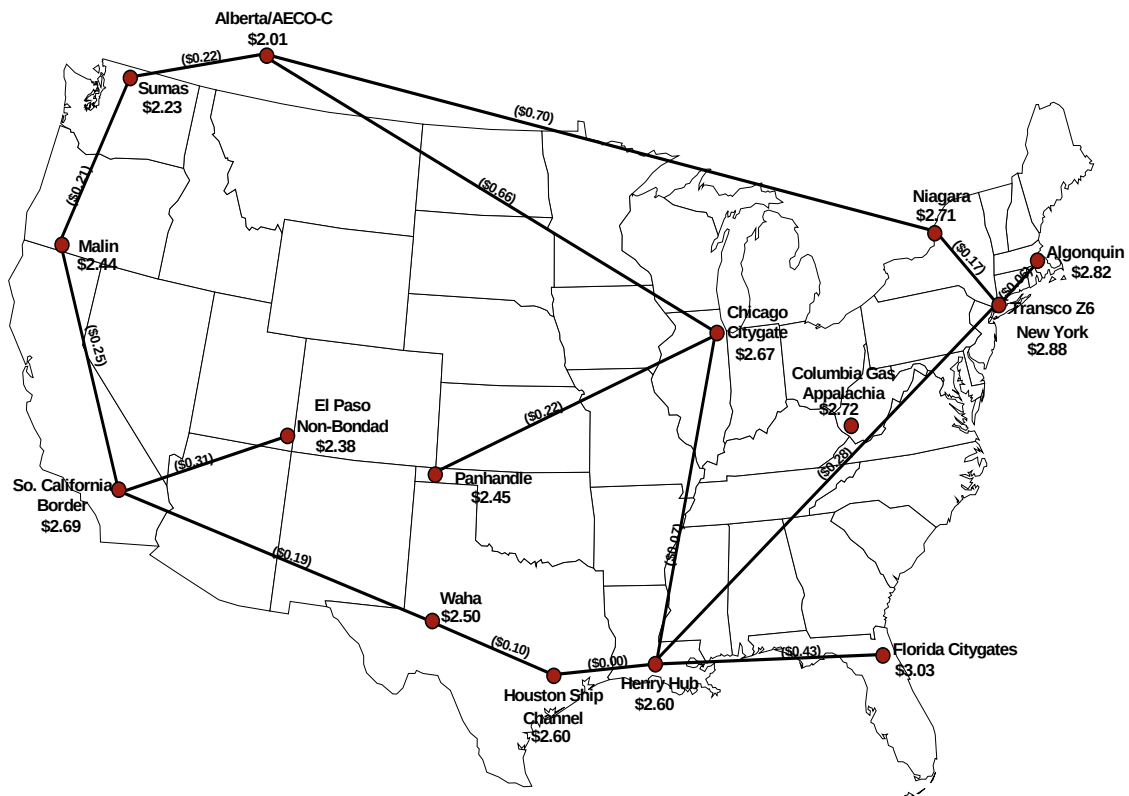
⁸³Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636-A, [Regs. Preambles Jan. 1991-June 1992] FERC Stats. & Regs ¶ 30,950, at 30,569 (1992).

⁸⁴The prices in downstream markets do not represent the price firm shippers would pay. A firm shipper could purchase gas at the Henry Hub price and would pay only the low usage charge to transport gas to Chicago.

higher priced market. For instance, the implicit value of transportation between the Henry Hub and the Chicago Citygate market was \$.07 in September 1999 (the difference between the \$2.67 price for gas in Chicago and the \$2.60 price at the Henry Hub).⁸⁵

⁸⁵A shipper would not pay more than \$.07 to transport gas purchased at \$2.60 at the Henry Hub to the Chicago Citygate market, because the shipper could buy gas for \$2.67 at the Chicago citygate.

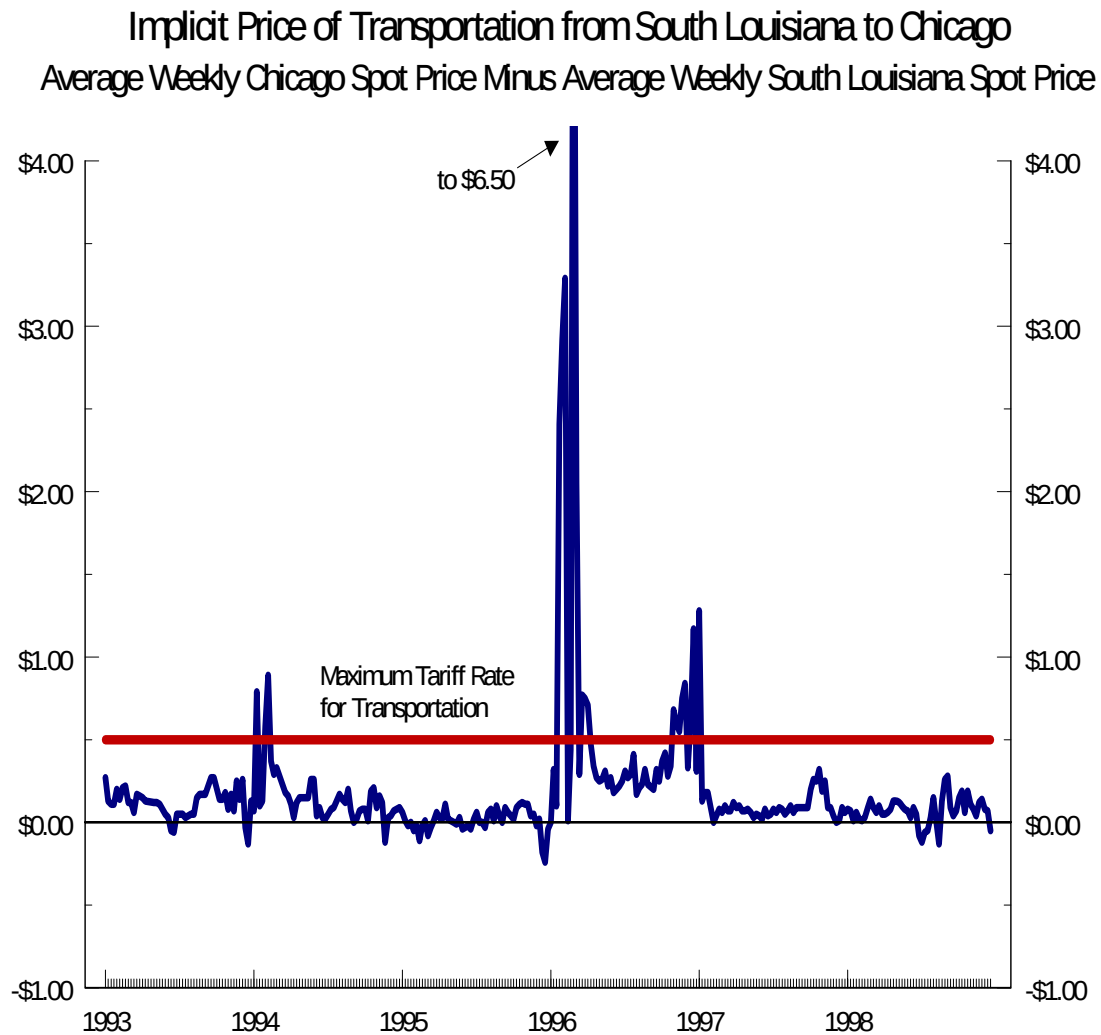
**Figure 5 -- Regional Natural Gas Prices and Differentials in Transportation Values
September 1999**



Source: Gas Daily, Weekly Weighted Average Prices. Data through September 30, 1999.
Note: Prices shown on map are in dollars per MMBtu.

The value of the transportation component of these bundled sales transactions results from the interaction of supply and demand forces and, unlike capacity release transactions, is not constrained by the maximum rate. Particularly during peak periods, shippers making bundled sales in the current market can avoid the maximum transportation rate and thereby obtain the market value for their capacity.

Figure 6 illustrates shows the increasing value of the transportation component during peak periods when demand for capacity is high. The transportation values in this chart represent the implicit amount that shippers that are unable to use firm capacity would pay for the transportation component of a bundled sales transaction. In the graph, for instance, the value of transportation rose to \$6.50/MMBtu during the peak winter period of 1995-1996, to \$1 during the winter of 1996-1997, and to less than \$.50 during the winter of 1997-1998.

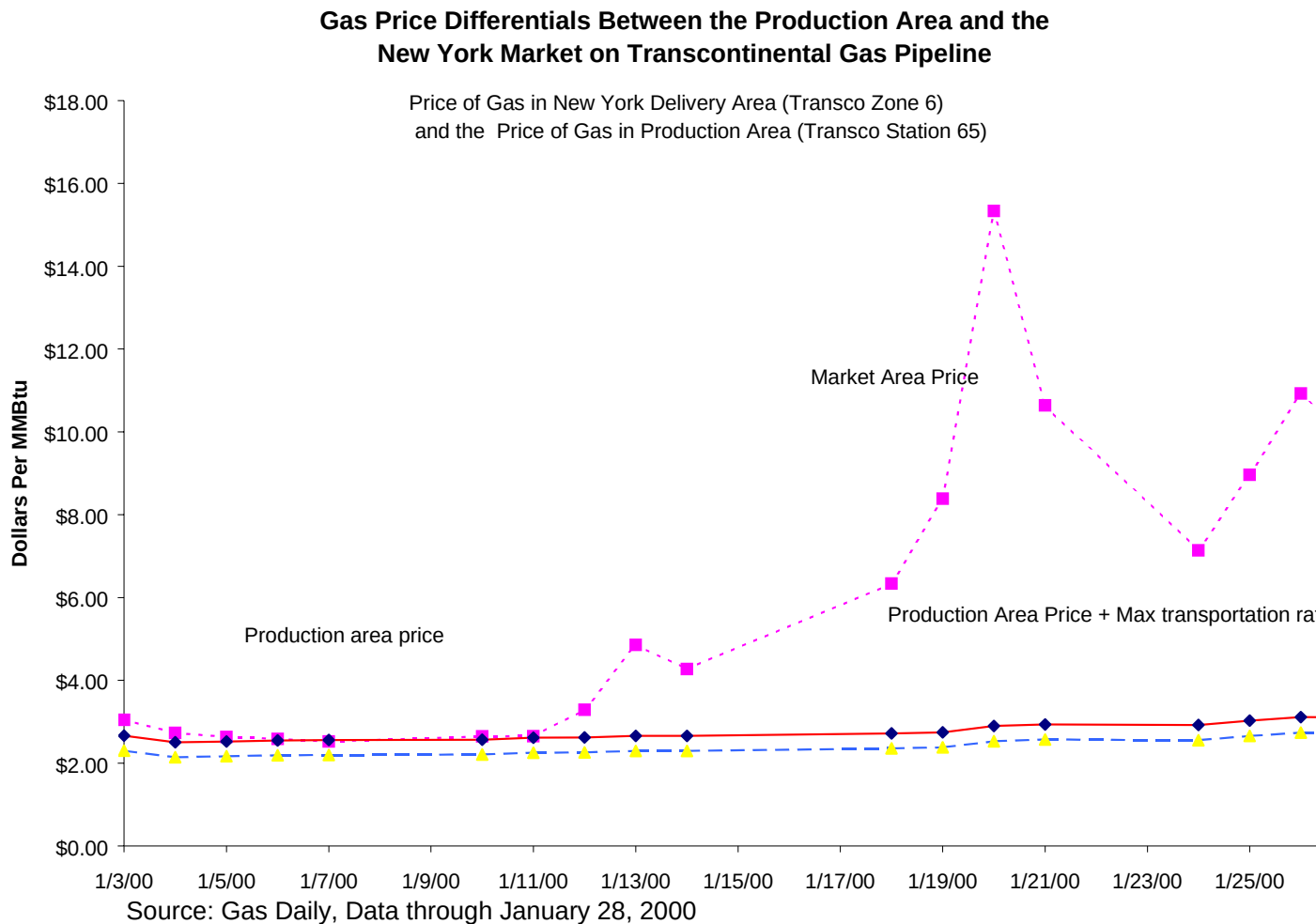
Figure 6 -- Implicit Transportation Values

Sources: *Gas Daily*, Weekly Weighted Average Prices and PI Grid. Data through December 31, 1998.
Tariff rate is the IT rate from Natural Gas Pipeline.

Figure 7 illustrates how the value of transportation can vary on a daily basis. This graph shows the price of gas in the New York market for January 2000 compared with the price of gas in the production area. The line entitled production area price plus maximum transportation rate reflects the price that would be paid by a shipper purchasing gas in the production area and transporting that gas to New York at the maximum interruptible transportation rate on the pipeline.⁸⁶ As the chart shows, as temperatures dropped in the Northeast during January,⁸⁷ the price of buying delivered gas in New York rose to \$15/MMBtu. In contrast, before the weather turned colder, the price of delivered gas in New York essentially reflected the price of gas in the production area plus the maximum transportation rate to transport that gas to New York. The difference between the price in the New York market area and the production area price represents the implicit price for (or value of) transportation paid by those shippers buying delivered gas in New York.

⁸⁶Firm shippers would pay a lower rate because they would pay the production area price plus a usage charge of only \$.0202 which is much lower than the maximum interruptible transportation rate of \$.3147. See Transcontinental Gas Pipe Line Corporation FERC Gas Tariff, Third Revised Volume No. 1, Eighth Revised Sheet No. 35-A (firm usage charge zones 4-6) and Eighth Revised Sheet No. 42 (interruptible rate zones 4-6).

⁸⁷The temperatures during this period changed from daily range in the low mid-thirties to low fifties to mid-thirties during the early part of the month to temperature ranges in the teens and low twenties during the later part of the month. The temperatures are reported at http://www.wunderground.com/US/NY/New_York.html (historical data).

Figure 7 -- Price Differentials During January 2000

Market Area Price -- The market area price is the price paid by short-term customers (those without sufficient firm capacity for their needs) to obtain gas in the New York market. Shippers using firm capacity would pay the production area price plus the 2¢ usage charge to transport gas to New York.

Production Area Price -- This is the price of gas purchased at the production area.

Production Area + Maximum Transportation rate -- This is the price a shipper would pay if it could buy gas in the production area and ship it to New York at the pipeline's maximum IT rate.

Value of Transportation -- The value of transportation is the area between the market area price and the production area price. During much of January, the value of transportation is shown to be about equal to the maximum IT rate. The value exceeds that rate only on days of peak demand.

These graphs show that the value of transportation, particularly during peak periods, is not related to the maximum tariff rates for transportation. As one commentator has stated, "gas commodity markets now determine the economic value of pipeline transportation services in many parts of the country. Thus, even as FERC has sought to isolate pipeline services from commodity sales, it is within the commodity markets that one can see revealed the true price for gas transportation."⁸⁸ Because the Commission's current regulatory model permits discounting below the maximum rate, the Commission's regulation does not inhibit pipelines and shippers from adjusting transportation rates to the off-peak demand in the market. However, during peak periods, the Commission's maximum rate cap does not allow unbundled transportation prices to equilibrate with demand.

The fact that the value of transportation in the short-term bundled sales market exceeds the daily or monthly maximum rate now permitted in pipeline tariffs is not surprising, nor is it evidence that market power is being exercised. The daily or monthly

⁸⁸M. Barcella, How Commodity Markets Drive Gas Pipeline Values, Public Utilities Fortnightly, Feb. 1, 1998, 24-25; See Henning & Sloan, Analysis of Short-Term Natural Gas Markets (Energy and Environmental Analysis, Inc., Nov. 1998) (showing how basis differentials between prices in different pipeline corridors correlate with value of capacity release transactions); B. Schlesinger, Natural Gas Industry Trends: Commoditizing Everything in Sight, <http://www.nymex.com> (November 17, 1999) (basis competition establishes the value of transportation capacity); R. O'Neill, C. Whitmore, M. Veloso, The Governance of Energy Displacement Network Oligopolies, Discussion Paper 96-08, at 41 Federal Energy Regulatory Commission, Office of Economic Policy, revised May 1997) (copy available from the Federal Energy Regulatory Commission) (the option to buy transmission rights is worth the difference in spot prices between two geographic areas, as opposed to a rate relating to embedded costs).

rates (derived by simple division of the annual rate) were never intended to replicate prices that demand conditions would produce.⁸⁹ Particularly during peak periods, the value of transportation will rise because the transportation quantity demanded begins to exceed the quantity of capacity supplied. As a result, a higher price is needed to efficiently allocate transportation to those who most need to obtain it and are willing to pay the highest price for the bundled commodity. Such price increases would occur in any competitive market when supply becomes constrained relative to demand. This situation must be distinguished from the exercise of market power when a pipeline has power to raise prices by withholding capacity, creating greater scarcity than would occur in a competitive market. Indeed, all commenters recognize that the bundled sales market operates independently of the regulated rate governing straight-forward (unbundled) capacity transactions, but none suggest that the Commission should attempt to impose more stringent regulation on the bundled sales market.

b. The Price Constraint for Capacity Release Transactions
Reduces Efficiency

⁸⁹The rationale for the Commission's method of regulating the rates of pipeline transactions does not apply to capacity release transactions. As discussed earlier, by regulating pipelines' rates so they cannot recover more than their annual revenue requirement, the Commission seeks to ensure that the pipelines do not have an incentive to withhold capacity to create excess returns. But this justification for rate regulation has little applicability to capacity release transactions, since releasing shippers are not in the position to withhold long-term capacity by failing to add capacity when necessary.

Applying a ceiling to the rate for capacity release transactions does not achieve the Commission's regulatory objectives. It reduces shippers' options, decreases the efficient operation of the market, and does not adequately protect captive customers.

Particularly during peak constraint periods on pipelines, preventing transportation prices from exceeding the pipeline's maximum rate can reduce the options of shippers purchasing in the short-term market. With the maximum rate cap, a shipper, without a contract sufficient to cover its requirements on a peak day, that is seeking to acquire additional capacity has limited options. It can first try to obtain pipeline interruptible capacity at the maximum rate cap, if the capacity is available. Even if pipeline capacity is available, the shipper may be unable to obtain that capacity despite placing the highest value on the capacity. Because the pipeline cannot exceed the maximum rate, the pipeline must allocate its available capacity either on a pro rata basis or on the basis of a queue based on contract execution date. In either case, a shipper may not obtain the capacity or the amount of capacity it needs regardless of whether it places the highest value on the capacity.

The shipper is therefore left with only two available options: to purchase gas in a bundled transaction in the downstream market at a price reflecting the market-determined value of transportation, or to simply take the gas out of the pipeline and pay the pipeline's scheduling or overrun penalties. The shipper generally will not be able to obtain released capacity at the capped price, because holders of that capacity are unlikely to release capacity at a price less than the amount they can receive by making a bundled sales

transaction. Thus, during a peak day, capping the price of released capacity does not effectively limit the price a purchaser has to pay to obtain transportation service. It only serves to limit the purchasing shipper's capacity options.

But the shipper's other options -- using a bundled sales transaction or incurring overrun and scheduling penalties -- may not be the most efficient choice. The purchaser may prefer not to use the bundled gas sales market when it has a natural gas contract at a less expensive price than the price of gas included in the bundled transaction and, as a result, would prefer to use its own gas. To use its own gas supplies to meet its peak day needs, the shipper would have to pay substantial penalties for overrunning its transportation contract. Shippers accumulating overruns also compromise the operational integrity of the pipeline's system, leading to a degradation of service for all shippers, including the possibility of service curtailment through operational flow orders, during peak periods when shippers most need the system to run efficiently.

Moreover, even if the maximum rate cap were more effective in limiting the prices at which firm capacity holders could resell capacity (for instance, LDCs who are unable to make bundled sales),⁹⁰ it would provide little benefit to shippers purchasing capacity during peak periods. The maximum rate cap reduces the efficiency of the market by preventing the efficient allocation of capacity to those who most need it and are willing to pay for it. During a time of capacity constraint, there may not be sufficient capacity to

⁹⁰See Comment of Arkansas PSC (price ceiling is effective, if at all, only on LDC capacity releases which tend to be unbundled sales of capacity).

serve all shippers seeking capacity at the maximum rate. It is therefore necessary to allocate or ration that capacity among the shippers desiring it. The Commission's regulations, in fact, require that one of the objectives in setting rates is to ration capacity during peak periods.⁹¹ The appropriate method of rationing scarce capacity is to allocate the capacity to those who place the greatest value on obtaining that capacity. Maximum rate regulation prevents such allocation during constrained periods, resulting in shippers who place a lower value on capacity retaining their capacity, rather than selling the capacity to shippers placing a greater value on obtaining the capacity.

Restrictions on capacity release transactions limit the development of an efficient and viable capacity market and can skew customer capacity choices. If a customer could rely on an effective short-term market to obtain additional capacity during peak periods, it might decide that it was not necessary to reserve sufficient long-term firm transportation to cover all of its peak day needs. It could be more economic for it to purchase short-term daily capacity, even at a high price, when it needed additional capacity, as opposed to paying for long-term capacity to meet peak needs. However, if the short-term market is less reliable, and, as a result, the customer valuing the capacity the most cannot acquire as much as it needs, the customer will be more reluctant to relinquish long-term capacity and rely upon the short-term market for its peak needs.⁹²

⁹¹18 CFR 284.7(b)(1), redesignated section 284.10(b)(1).

⁹²The comments recognize that the Commission's current regulatory policy can
(continued...)

Indeed, the use of the pipeline's maximum rate as the cap for capacity release transactions, can reduce the amount of released capacity available during peak periods, precisely the period when capacity is needed most. As a result of the maximum rate, firm capacity holders may not find it sufficiently profitable to make their capacity available for release. For instance, a dual fuel industrial customer might determine that it would be more economic not to use gas, and to substitute a different fuel, if it could obtain a sufficiently high price for its released capacity. Similarly, an LDC might have a peak shaving capability (storage or liquefied natural gas (LNG)) that costs more to produce and deliver gas than purchasing the gas in upstream markets and using its transportation capacity to transport that gas to its citygate. The LDC might be willing to release its transportation capacity and use the peak shaving device instead if it could receive a price above the maximum rate for its transportation capacity so that the amount it receives for the release of its transportation capacity covers the costs of the peak shaving device.⁹³ By

(...continued)

result in market distortions and inefficiencies. See Comments of Amoco I, at 17-18 ("maximum rates can result in inefficiencies); INGAA, at 25 (graph of transportation value shows that the market value of capacity is less than its allocated cost during off-peak periods and must be discounted); AGA I, at 13 (off-peak customers receive transportation at discounted rates which cannot be recouped during peak periods); El Paso Energy, Appendix A (allocative inefficiencies exist when prices exceed maximum rate).

⁹³Suppose the costs to the LDC of using the peak shaving device were \$6.00/MMBtu and the costs of buying gas in the upstream market was \$4.00/MMBtu with a \$.10/MMBtu usage charge (under its firm contract) for transportation. If the LDC could resell its transportation capacity for more than \$1.90/MMBtu (the difference between using its peak shaving device and its transportation service), it would release that
(continued...)

using its peak shaving device instead of transportation, the shipper would be expanding the amount of released capacity available during a peak period. But if the price cap prevents the shipper from obtaining a price higher than the cost of the peak shaving device, and the shipper cannot sell the gas on a delivered basis, the shipper will use its transportation capacity, thus depriving other shippers (without peak shaving) of the opportunity to acquire needed transportation capacity. Removal of the price cap, therefore, could make additional released capacity available during peak periods to those most needing that capacity. As more capacity enters the marketplace during peak periods, the consequence would be a lowering of transportation prices, which would be of significant benefit to all shippers needing capacity when the pipeline system is most constrained.⁹⁴

Capping capacity release transactions during peak periods at the current maximum rate system also harms captive customers holding long-term contracts on the pipeline. These customers have to pay maximum rates for both peak and off-peak periods. During off-peak periods, when prices are generally low, they cannot recover the cost of their

⁹³(...continued)
capacity and use its peak shaving instead. If the release were subject to a maximum cap of less than \$1.90, however, the LDC would choose not to peak shave and the capacity would not be released to others.

⁹⁴See Comments of Amoco I, at 17-18 ("incremental costs due to market inefficiencies (which may be described as transaction costs) may arise during periods when the demand for capacity exceeds its supply, resulting in delivered gas prices in downstream markets that are higher than they would be in a more allocatively efficient, i.e., liquid and transparent market").

investment. But, when demand increases the value of capacity, captive customers cannot reap the benefits of the higher value through a straight-forward release of capacity.

Instead, their only alternative in selling capacity is to seek to make bundled sales transactions, which may be more difficult for smaller customers and raise transactions costs for both parties.

2. Alternatives to the Price Cap

In the NOPR, the Commission proposed one alternative to respond to the inefficiencies created by price caps, as well as requesting comments on other approaches. The Commission proposed to eliminate the maximum rate from both short-term (less than one year) capacity release and pipeline transactions, together with a number of proposals to increase competition in the short-term market and limit the exercise of market power. Chief among the proposals was the requirement that all short-term capacity would be sold through an auction process in which daily pipeline capacity would be sold without a reserve (or minimum) price. The purpose of the no-reserve price proposal was to protect against the exercise of market power in the short-term market by ensuring that pipelines could not withhold capacity. In addition, the Commission solicited comment on other potential approaches, such as the use of seasonal rates or the application of market power analysis similar to that used in the Alternative Rate Design Policy Statement,⁹⁵ to

⁹⁵ Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), 74 FERC ¶ 61,076 (1996).

determine whether markets are sufficiently competitive to remove regulatory rate ceilings for all services.

The comments, for the most part, do not challenge the Commission's analysis of the inefficiencies created by maximum rate regulation in the short-term market, but they take very different positions as to the possible solution. Some commenters, principally pipelines, support removal of the price cap for all services in the short-term market, contending removal would improve market efficiency, mitigate the adverse effects of the current cost-based rate designs, increase competition, and remove a major obstacle to contracting for long-term capacity.⁹⁶ Many of the comments, however, contend that the Commission should not remove rate regulation over pipelines, because pipelines continue to hold market power. They maintain that rate caps can be removed only upon a showing that market power cannot be exercised.⁹⁷ Several commenters, particularly LDCs, support removal of price caps for short-term capacity release transactions, but not for pipeline services.⁹⁸

⁹⁶Comments of Consolidated Natural Gas I, IMD, Koch I, MichCon, NYMEX, Nicor, PG&E, Mercatus, Sempra Energy, TransCanada, and Williams I.

⁹⁷Comments of Arkansas Gas Consumers, Market Hub Partners, NWIGU, Process Gas Consumers, et al., and Southern Company Services, Amoco I, IPAA, Indicated Shippers, NGSA, PanCanadian, PSC of New York I, and CPUC.

⁹⁸Comments of AGA I, Arkansas PSC, ConEd, Enron Pipelines, Illinois Commerce Commission, INGAA, NARUC, NASUCA, Nisource, Pennsylvania/Ohio Consumer Advocates, Pennsylvania PUC, Philadelphia Gas Works, Piedmont/UGI, PSC of Wisconsin I, PUC of Ohio, and Washington Gas Light.

Some commenters support the use of auctions as a method for limiting the exercise of market power and providing a non-discriminatory method for allocating capacity, although they recognize that there may be a need to implement some mechanism to protect pipelines against cost under-recovery.⁹⁹ By far the vast majority of commenters, however, oppose the use of mandatory auctions at this time, principally out of a concern that auctions would be complex and expensive, would require more personnel to monitor the auctions on multiple pipelines, would not work as efficiently as the use of pre-arranged deals for capacity exchanges, would not permit coordination between gas and capacity purchases, could interfere with state unbundling plans by inhibiting prearranged releases, and would frustrate asset management arrangements.¹⁰⁰ INGAA and AGA raise concerns about the impact of mandatory no-reserve price auctions on pipelines' or firm

⁹⁹Comments of Altra, Amoco I, Florida DMS, Sithe, Southern Company Energy Marketing, and Southern Company Services. While not directly supporting removal of the maximum rate cap, Indicated Shippers and NGSA maintain that if the price cap is lifted, auctions need to be required.

¹⁰⁰Comments of AEC Marketing, Allenergy Marketing, et al., AGA I, CMS Panhandle, Coastal I, Colorado Springs I, Columbia LDCs, Consolidated Natural Gas I, Cove Point, Duke Energy Trading, El Paso, Enron Pipelines, INGAA, KN, Koch I, Louisville, Mississippi Valley, et al., National Fuel Gas Supply, Nisource, NWIGU, PanCanadian, Pennsylvania PUC, Peoples Energy I, Philadelphia Gas Works, Piedmont/UGI, Process Gas Consumers, et al., Reliant, Sempra Energy, TETCO/Algonquin, TransCanada, Williston Basin, Williams I, and UGI. Other commenters, while not specifically opposing auctions, raise similar concerns about the use of auctions. APGA, Enron Capital & Trade, Entergy, Fertilizer Institute, Foothills, Illinois Commerce Commission, IMD, Market Hub Partners, NARUC, Nicor, PG&E, PNGTS, Proliance, PSC of Kentucky, PSC of New York I, PSC of Wisconsin I, CPUC, Mercatus, Shell, and Southwest Gas.

shippers' abilities to recover their investments. Several commenters suggest the use of voluntary rather than mandatory auctions as a way to gain more experience with auctions.¹⁰¹ Others suggest that while auctions may be a viable method of allocating capacity, a mandatory auction may not be the most efficient method of allocating capacity and may inhibit the development of other equally efficient approaches, in particular pre-arranged deals. They suggest that the Commission should not mandate the use of auctions, but instead consider a variety of options, including auctions that would prevent withholding of capacity.¹⁰²

In place of mandatory auctions, INGAA, along with most pipelines, and AGA, and most of the LDCs, propose an alternative to mandatory auctions under which the Commission would remove maximum rate caps from capacity release transactions, but not pipeline transactions. INGAA and AGA argue that such an approach would eliminate inefficiencies in the marketplace while preserving pipeline capacity as a "just and reasonable" safe harbor or recourse service. INGAA also proposes that pipelines be permitted to institute seasonal rates to better reflect peak and off-peak demands faced by many pipelines. INGAA maintains that permitting pipelines to institute seasonal rates where demand differs throughout the year would help to ameliorate the inequities of the current ratemaking structure in which shippers purchasing short-term capacity are able to

¹⁰¹Comments of Colorado Springs I, Enron Capital & Trade, Enron Pipelines, INGAA, K N, National Fuel Gas Supply, Sempra Energy, and TransCanada.

¹⁰²Comments of Mercatus; CAPP/ADOE.

shift costs to those customers purchasing capacity on a long-term basis at maximum rates. INGAA further proposes that seasonal rates be cost-based in the sense that they be limited by the pipeline's revenue requirement. INGAA suggests a number of ways in which seasonal rates could be designed, for instance, using seasonal pipeline utilization, and others suggest other approaches.¹⁰³

3. The Regulatory Changes Implemented in this Rule

In this rule, the Commission is revising its policies on rate regulation to improve marketplace efficiency by adopting the two-part approach suggested by commenters: removing the rate ceiling for capacity release transactions and clarifying its policy on seasonal rates to permit pipelines to file for differing peak and off-peak rates based on different demand conditions on those pipelines. The Commission is waiving the rate ceiling in its capacity release regulations¹⁰⁴ until September 30, 2002 for short-term releases of capacity of less than one year beginning upon the effective date of this rule. The Commission, however, is continuing its current regulations regarding the posting and bidding for capacity release transactions of greater than one month.

While the removal of the price cap is justified based on the record in this rulemaking, the Commission recognizes that this is a significant regulatory change that should be subject to ongoing review by the Commission and the industry. No matter how

¹⁰³Comments of Enron Pipelines, Amoco I.

¹⁰⁴The waiver is contained in redesignated 284.8 (i). The existing capacity release regulations are not being revised.

good the data suggesting that a regulatory change should be made, there is no substitute for reviewing the actual results of a regulatory action. The two year waiver will provide an opportunity for such a review after sufficient information is obtained to validly assess the results. Due to the variation between years in winter temperatures, the waiver will provide the Commission and the industry with two winter's worth of data with which to examine the effects of this policy change and determine whether changes or modifications may be needed prior to the expiration of the waiver.

At this point, the Commission is retaining the price cap for capacity release transactions over one year because this rule is focused on revising regulations that interfere with the efficient allocation of capacity during the short-term periods when demand pushes the value of transportation above the current maximum rate. There has been no showing made that for capacity release transactions of one year or more the value of capacity exceeds the uniform annual rate such that maximum rates impede efficiency. This policy too may be reassessed based on the results during the two year waiver period.

a. Consistency with the Commission's Regulatory Objectives

The removal of the price cap from short-term capacity release transactions better satisfies the Commission's regulatory objectives than the current system. Removal of the rate cap will expand shippers' options, create a more efficient marketplace, increase market transparency, and better protect captive customers, without changing the current regulatory environment.

Removal of the rate ceiling from short-term capacity release transactions will remove an impediment to the development of an efficient capacity market by giving purchasers an additional option for obtaining capacity during peak periods. Instead of having only the choices of purchasing a bundled sale or incurring a contract overrun, a customer needing gas can directly obtain the capacity it needs from a firm capacity holder. Removal of the rate ceiling for capacity release transactions also will enhance efficiency by ensuring that capacity is properly allocated to those placing the most value on obtaining capacity during peak periods.

By fostering a more efficient short-term market, removal of the rate ceiling on short-term capacity release transactions will help create a more reliable short-term capacity market where shippers who need short-term capacity will know they can obtain as much capacity as they need by paying the market price. The development of a more reliable short-term capacity market, in turn, will enable shippers to make better informed choices about whether to purchase long or short-term capacity depending on their circumstances. Some shippers may prefer the price stability they obtain from a long-term firm contract. On the other hand, some shippers may opt not to contract for long-term capacity if they are assured of a reliable short-term capacity market in which they could obtain transportation by offering to pay the market price for the capacity.¹⁰⁵ Even

¹⁰⁵ A low load factor shipper (one with greater demand during peak than off-peak) might find that paying reservation rates for a full year to hold long-term capacity sufficient to meet its peak needs is less economic than purchasing capacity only for the
(continued...)

demand inelastic customers in Chicago might not want to subscribe to sufficient firm capacity to meet the worst-case scenario that occurred in 1996¹⁰⁶ if an effective spot market exists in which they can obtain capacity when needed or hedge against the financial risk of buying in the spot market.

The more reliable the market the less shippers and regulators may be pushed toward requiring long-term capacity contracts to ensure reliability. For example, with an effective market for transportation capacity, there could be less need for states contemplating retail unbundling to require marketers or LDCs, as suppliers of last resort, to hold firm capacity on pipelines to guarantee transportation, just as long-term contracts are no longer necessary to guarantee access to the gas commodity.

Removal of the rate cap for short-term capacity release transactions also will have an added benefit of increasing market transparency. In today's market, there is little information on the price of transportation capacity during peak periods, because, due to the price caps, transactions move to the bundled sales market. Permitting transportation capacity to trade freely during peak periods will increase the number of transactions moving from the bundled sales market to the transportation market, which, given the

¹⁰⁵(...continued)

short time when it needs the capacity even if the rate for that short-term capacity is much higher than the yearly rate.

¹⁰⁶See Figure 6, supra (showing the spike in gas prices to \$6.50/MMBtu during the winter of 1996).

changes in reporting requirements adopted in this rule, will increase pricing information during peak periods, when such information is most critical to the marketplace.

Removal of the rate ceiling will have limited effect on the effective prices paid by customers using short-term transportation capacity. In today's market, when the value of transportation exceeds the maximum rate, firm capacity holders have an incentive not to release capacity, but to bundle that capacity with gas so that they can obtain the full market value of the transportation capacity by selling gas in the delivery market. Thus, removal of the rate ceiling should not significantly raise transportation prices, but will instead provide shippers looking for capacity with the alternative of buying transportation capacity directly rather than obtaining that capacity indirectly through a bundled sale.

Moreover, even if some replacement shippers do end up paying higher prices for capacity during peak periods than they did with the regulated rate in effect, it is appropriate for shippers using the system only during peak periods to pay higher prices reflecting the greater demand on the system. Short-term shippers currently receive the benefit of paying reduced capacity release prices during off-peak periods, but face a cap on the market price during peak periods. Removal of the rate ceiling on capacity release prices will ensure that those shippers which receive the benefit of lower market prices during off-peak periods face the higher market prices during peak periods. Removing the price ceiling for released capacity also will benefit captive customers by eliminating the regulatory bias built into the current rate structure. Long-term shippers pay the same rate for capacity during both peak and off-peak periods. During off-peak periods, they can

recover only a small portion of their capacity cost through capacity release, because the market value for released capacity is generally quite low due to the reduced demand for capacity and the increased availability of released capacity. But during peak periods, the price cap limits long-term captive customers (who cannot make bundled sales) from receiving the full market value of their capacity. Long-term shippers pay for the largest proportion of the pipeline's fixed costs through their annual reservation charges, and permitting them to receive more revenue from capacity release transactions during peak periods will help them defray those costs.

b. Protections Against the Exercise of Market Power

While removal of the rate cap for short-term capacity releases will add an additional capacity option, such removal does not significantly reduce the protection of shippers buying short-term transportation. First, the capacity release rate cap is largely ineffective in protecting short-term capacity purchasers in today's market since shippers can make bundled sales to evade the cap. Thus, removal of the rate cap will not provide releasing shippers with significant additional pricing freedom. Instead, it will improve the market for buyers by giving them an additional capacity option from which to choose.

Second, the fact that prices for transportation rise during peak periods is not evidence of the exercise of market power, but may be the appropriate market response to an increase in demand for capacity. During peak periods when there is insufficient capacity to satisfy all the demand for short-term capacity, an increase in market price

would be the competitive response to a situation in which the quantity of transportation demanded increases relative to the quantity that can be supplied.

The rule also continues to provide protections against the possible exercise of market power by releasing shippers. Market power can be exercised in two ways: through withholding capacity to raise price or through price discrimination.

Firm shippers cannot successfully withhold capacity from the market to raise price above the existing maximum just and reasonable rate because, if the firm shippers do not use their capacity, the pipeline has the incentive to sell the capacity as interruptible service. Moreover, the Commission is continuing to protect against the possibility that, in an oligopolistic market structure, the pipeline and the firm shippers will have a mutual interest in withholding capacity to raise price because the Commission is continuing cost-based regulation of pipeline transportation transactions. The pipelines will be required to sell both short-term and long-term capacity at just and reasonable cost-based rates. In the short-term, a releasing shipper's attempt to withhold capacity in order to raise price above maximum rates will be undermined because the pipeline will be required to sell that capacity as interruptible capacity to a shipper willing to pay the maximum rate. Shippers also have the option of purchasing long-term firm capacity from the pipelines at just and reasonable rates.

In addition, the ability of pipelines to build additional capacity will check the potential exercise of market power by releasing shippers. Regardless of the value of scarce capacity, pipelines' rates are capped. Thus, if a pipeline observes that the market

price for capacity exceeds the pipeline's maximum rate in the short-term market, and the market prices are sufficient to cover the cost of new pipeline capacity, the pipeline can capture that revenue only by building additional capacity to serve the demand. In many cases, capacity can be added relatively quickly simply by adding compression. Thus, firm shippers have little incentive to exercise market power by withholding capacity given the pipeline's ability and incentive to dissipate that market power through new construction.

The cost-based regulation of pipeline services also limits firm shippers' ability to price discriminate, since a purchaser who is unwilling to pay the price quoted by the releasing shipper can obtain pipeline capacity at cost-based rates. Firm shippers also would have difficulty engaging in price discrimination, because, given the ease with which capacity can be transferred between shippers, a releasing shipper would have trouble preventing arbitrage -- a shipper which benefits from the lower price buying more capacity than it needs and reselling the excess to less-favored shippers.¹⁰⁷

Besides the availability of pipeline capacity, the competitive pressures fostered by competition from released capacity will limit the potential exercise of market power. Many of the commenters argue that due to the competition for released capacity, release rates are low and firm shippers are unable to come close to recouping their investment in

¹⁰⁷ See Comment of Mercatus (price discrimination cannot be maintained where releasing shipper cannot limit arbitrage).

pipeline capacity.¹⁰⁸ CNG cites to a study commissioned by AGA and INGAA analyzing 17 major pipeline corridors, which showed that the average value of capacity release transactions varied from 31% to 76% of the maximum rate tariff rate applicable to the corridor.¹⁰⁹

Since Order No. 636, capacity release transactions have grown significantly, averaging 20 trillion Btu/day, for a total of 7.4 quadrillion Btu for the 12 month period ending March, 1997.¹¹⁰ Competition from numerous shippers releasing capacity, therefore, will also lessen the ability of firm shippers to exercise market power. The Commission's policy requiring pipelines to provide flexible receipt and delivery points rights has enhanced competition. Due to the ability to use alternate receipt and delivery points, capacity purchasers are not limited to purchasing capacity only from shippers holding the primary point rights the purchaser needs. A purchaser can obtain capacity from any of a number of shippers and use the flexibility to use alternate points to access the receipt and delivery points it needs. In this rule, the Commission is improving various aspects of the capacity release mechanism, by speeding up the nomination process and

¹⁰⁸Comments of AGA I, Arkansas PSC, Consolidated Edison, Enron Pipelines, Illinois Commerce Commission, INGAA, NARUC, NASUCA, Nisource, Pennsylvania/Ohio Consumer Advocates, Pennsylvania PUC, Philadelphia Gas Works, Piedmont/UGI, PSC of Wisconsin, PUC of Ohio, and Washington Gas Light.

¹⁰⁹The study cited is Henning & Sloan, Analysis of Short-Term Natural Gas Markets (Energy and Environmental Analysis, Inc., November 1998).

¹¹⁰Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0618(98), Deliverability on the Interstate Natural Gas Pipeline System 83 (1998).

requiring pipelines to permit shippers to segment capacity, which will further enhance competition between releasing shippers. Thus, capacity available from other shippers together with the availability of pipeline capacity will limit the ability of releasing shippers to exercise market power.

As additional protection against the potential exercise of market power, the Commission in this rule is improving its reporting requirements to permit better monitoring of the marketplace and has recently instituted a revamped complaint process.¹¹¹ The improved reporting requirements will improve competition in the market by expanding shippers' information about potential capacity alternatives. Difficulty in obtaining information can reduce competition because buyers may not be aware of potential alternatives and cannot compare prices between those alternatives. The reporting requirements will expand shippers' knowledge of alternative capacity offerings by providing more information about the capacity available from the pipeline as well as those shippers holding capacity that is potentially available for release. The reporting requirements further will provide shippers with more accurate information about the value of capacity over particular pipeline corridors so that shippers can make more informed choices about the prices of capacity they may wish to purchase.

¹¹¹18 CFR 385.206 (adopted by Complaint Procedures, Order No. 602, 64 FR 17087 (Apr., 8, 1999), III FERC Stats. & Regs. Regulations Preambles ¶ 31,071 (Mar. 31, 1999).

In addition to providing better information about competitive alternatives that will enhance competition, the improved reporting requirements will better enable shippers and the Commission to monitor the market. Thus, both shippers and the Commission will be better able to identify situations in which market power is being abused, and the Commission will have more information to use in tailoring remedies in individual cases as the need arises.

Thus, the removal of rate ceilings will improve shipper options, create a more efficient marketplace, and make the Commission's ratemaking policies more responsive to market forces. Reasonable protection against the exercise of market power by releasing shippers will be provided by continuing cost-of-service regulation of the pipelines and competition in the release market, together with enhanced reporting requirements that will improve information about capacity alternatives and shippers' ability to monitor the market for market power abuses.

4. Legal Basis for Removing the Rate Ceiling for Short-Term Capacity Release Transactions

Several commenters maintain that, under its statutory mandate, the Commission cannot legally rely upon market-based rates without making a finding that market power cannot be exercised.¹¹² APGA, for example, contends that the existence of the bundled sales market should not be used as justification for removing rate regulation in the

¹¹²Comments of Process Gas Consumers, Indicated Shippers, NGSA, APGA, IPAA.

capacity market. Process Gas Consumers (Process Gas Consumers I) and Indicated Shippers (Indicated Shippers Reply) contend the Commission cannot remove price caps for released capacity even if ceilings remain on pipeline capacity.

The Commission concludes that the removal of the price cap for capacity release transactions, together with continued regulation of pipeline rates, comports with its statutory responsibilities. The Commission has the statutory obligation under the NGA to ensure that pipeline rates and services are just and reasonable. Establishing just and reasonable rates requires the Commission to protect consumers of natural gas from the exercise of monopoly power by pipelines,¹¹³ while, at the same time, ensuring that those rates improve the competitive structure of the natural gas industry to maximize the benefits of wellhead decontrol."¹¹⁴ In seeking to achieve these goals, the courts have recognized that the Commission is not bound to use any particular pricing formula in determining just and reasonable rates¹¹⁵ and that cost-based regulation can be relaxed as long as the overall "regulatory scheme" ensures that rates are within a zone of

¹¹³FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.").

¹¹⁴Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101-29, 101st Cong., 1st Sess., at 6 (1989); Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,939, at 30,932 (Apr. 8, 1992).

¹¹⁵FPC v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944); Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993).

reasonableness.¹¹⁶ The Commission is permitted to move to lighter-handed regulation as long as it ensures that the goals and purposes of the statute will still be accomplished.¹¹⁷ The courts have permitted the Commission to institute flexible pricing to improve market efficiency so long as the overall regulatory scheme protects against price gouging.¹¹⁸ Market-based rates have been approved when the Commission has found sufficient protection against the exercise of market power.¹¹⁹

The Commission finds that the regulatory changes made in this rule ensure a regulatory scheme that protects against the exercise of market power and ensures that rates are within the "zone of reasonableness" even without a price cap on short-term capacity release transactions. In the first place, the removal of the rate cap for capacity release transactions does not effectively change the status quo, since the value of transportation in the bundled sales market can exceed maximum tariff-based rates. Thus, continuation of the maximum rate cap on unbundled capacity release transactions does little to protect against the exercise of market power by firm capacity holders. Its principal effect is to provide shippers with additional transportation options, to create greater efficiency in capacity allocation, and to move transactions from the less-well-

¹¹⁶See *Farmers Union Central Exchange v. FERC*, 734 F.2d 1486, 1509-10 (D.C. Cir. 1984).

¹¹⁷*Farmers Union*, 734 F.2d 1486 at 1510.

¹¹⁸ *Environmental Action v. FERC*, 996 F.2d 401, 410 (D.C. Cir. 1993).

¹¹⁹ *Elizabethtown Gas Company v. FERC*, 10 F.3d 866 (D.C. Cir. 1993).

reported bundled sales market to the better-reported transportation market. By removing the price cap from capacity release transactions, the Commission is not reducing protection for customers seeking released capacity, but is expanding their options and helping to foster a more efficient and transparent marketplace for released capacity.

In addition, the Commission is not adopting market-based rates for all capacity. It is removing rate regulation only from one element of the competitive mix -- short-term capacity release transactions by shippers -- while retaining regulation for sales of pipeline capacity. The Commission also is continuing to protect its primary constituency -- captive long-term firm capacity holders -- by continuing the same cost-of-service rate regulation that has been used for years.¹²⁰ The regulatory change in this rule affects only shippers buying short-term released capacity who are already at risk of not being able to acquire capacity.¹²¹ As explained earlier, the Commission's regulation of pipeline transactions, as well as the operation of market forces, also will protect against the exercise of market power and keep capacity release rates within the zone of reasonableness.

¹²⁰See *Maryland People's Counsel v. FERC*, 761 F.2d 768 (D.C. Cir. 1985); *Maryland People's Counsel v. FERC*, 761 F.2d 780 (D.C. Cir. 1985) (special concern for effect of program on core captive customers).

¹²¹See *American Gas Association v. FERC*, 912 F.2d 1496, 1518 (D.C. Cir. 1990) (interruptible and short-term capacity holders not entitled to the same protection against market power as long-term firm capacity holders).

AFPA contends that short-term shippers may be captive customers. But, short-term customers, those using interruptible or short-term firm pipeline service or relying on capacity release transactions, are, by the very nature of the services for which they contract, not captive. They are expressly taking the risk that during peak periods, they will be unable to obtain capacity and either are willing to forgo the use of gas entirely or are willing to pay the prices needed to obtain gas from alternative sources. Such customers, in fact, receive more protection if they can obtain the capacity they need by offering a sufficiently high price than if the price is regulated and they are unable to obtain capacity at all. If short-term customers want the insurance of having guaranteed transportation service, that security is available by obtaining long-term firm capacity from the pipeline.

Moreover, as explained in the previous section, the availability of regulated pipeline capacity as well as competition between holders of firm capacity mitigates the potential for releasing shippers to exercise market power. In Environmental Action v. FERC,¹²² the court recognized that the Commission may need to relax price regulation in order to improve market efficiency and approved a flexible pricing program as long as the program maintained protections against the exercise of market power.¹²³ Here, the

¹²² Environmental Action v. FERC, 996 F.2d 401 (D.C. Cir. 1993).

¹²³ As the Court stated:

We acknowledge that the flexible pricing that fosters trading among
(continued...)

Commission similarly is improving the efficiency of capacity trading during peak periods while maintaining cost-of-service regulation for pipeline firm and interruptible service that will limit the ability of both firm capacity holders and the pipelines to exercise market power by withholding capacity.

Indicated Shippers suggest that removing the rate ceiling from capacity release transactions will permit firm capacity holders to exercise market power by withholding capacity from the market because they are not obligated to release that capacity. However, removing the rate ceiling will not permit a firm shipper to withhold capacity from the market to raise price above the maximum rate, because, in the short-run, that capacity always will be available from the pipeline as interruptible capacity, which the pipeline is obligated to sell at the approved just and reasonable rate. In the long run, pipeline firm transportation also is available as a check against short-term market power and the continuation of cost-of-service regulation for the pipelines provides an incentive for the pipeline to build additional capacity when justified by demand.

¹²³(...continued)

members of the Pool also permits price discrimination especially against captive utilities. Yet, given the benefits of this trading, the limited number of captive members, and the provisions for monitoring transactions and remedying any abuses of market power, we do not find that the Commission acted arbitrarily when it approved the use of flexible prices despite their admitted risk.

Process Gas Consumers maintains that competition may not limit the market power held by LDCs because they control access to primary delivery points and that obtaining secondary point access from other firm holders may not be the equivalent of obtaining primary point access from the LDC, particularly during periods of constraint when the pipeline may interrupt secondary deliveries. Process Gas Consumers also maintains that LDCs, by virtue of their control over their own facilities, can exercise market power over customers behind the city-gate and contends the Commission should not remove price ceilings for LDCs unless the LDCs provide shippers with reasonable city-gate access.

The Commission does not find that LDCs should be treated differently than other firm shippers with respect to their ability to release capacity. Such a distinction would skew the capacity release market by creating different classes of customers: one class without a price ceiling and the LDCs with a price ceiling. An LDC also is not more likely than other firm shippers to exercise market power by withholding capacity, because if it tried to do so, the capacity would be available from the pipeline as interruptible transportation, which the pipeline is obligated to sell at just and reasonable rates.

Moreover, as Process Gas Consumers itself recognizes, the Commission's jurisdiction does not extend to LDC activity behind their city-gates, which are the province of state regulatory authorities. Complaints about LDCs handling of transportation on their own systems are properly directed to the state regulatory agencies with jurisdiction over those activities. To the extent that an LDC engages in specific

abuses of its market power over interstate transportation capacity, the Commission can remedy such abuses through individual action. The improved reporting requirements together with the Commission's revised complaint process will enable both shippers and the Commission to discern and redress abuses of market power. The possibility of abuse in specific circumstances, which can be addressed on an individual basis, should not preclude the Commission from adopting a policy that benefits the industry as a whole by enhancing customer options and improving marketplace efficiency.

AlliedSignal complains that removal of the price cap will leave the market open to hysteria leading to exorbitant prices during times of peak demand. In the first place, high prices during peak demand periods can be a function of supply and demand forces that raise prices to allocate capacity during peak periods. As long as capacity is not being withheld from the market and no discrimination is taking place, the high prices are a reasonable and necessary competitive response to market conditions to allocate capacity to those needing it the most. Indeed, as shown by the period of rate regulation of wellhead prices, maintenance of regulated prices can distort the market by upsetting the balance between supply and demand.¹²⁴ In any event, continuation of rate regulation for capacity release transactions will not limit the effect of so-called market hysteria, since the Commission's rate regulation has no effect on the prices for bundled gas and

¹²⁴See *Transcontinental Gas Pipe Line Corporation v. State Oil and Gas Board*, 474 U.S. 409, 420 (1986) (Natural Gas Act's artificial pricing scheme is a major cause of imbalance between supply and demand).

transportation capacity. Removal of price regulation from short-term capacity release transactions, therefore, will not add to pricing problems during peak periods, but instead should help to minimize these problems by increasing customers' options.

Dynegy and Process Gas Consumers raise the question of whether pipelines can avoid protections against the exercise of market power by transferring capacity to their affiliates. In one respect, transfers of capacity to affiliates will not enable the corporate entity to exercise market power. Affiliates, like LDCs or other firm capacity holders will not be able to exercise market power, because they cannot effectively withhold capacity. If the affiliate refuses to release capacity, the pipeline still is obligated to sell the capacity at just and reasonable rates and cannot conspire with the affiliate to withhold capacity.

In another respect, transfers of capacity to affiliates could be troublesome, but not because the affiliate could exercise market power in the release market. One aspect of Commission regulation is intended to ensure that pipelines have the incentive to expand their pipeline when it is economic to do so. Through cost-of-service of regulation, the Commission ensures that pipelines do not benefit by creating scarcity by refusing to build long-term capacity.¹²⁵ However, if a pipeline affiliate holds a large enough block of capacity on its related pipeline, the corporate entity as a whole could benefit if the

¹²⁵Under cost-of-service regulation, the pipeline can only recover the costs of its investment in pipeline facilities. It cannot capture added revenues by refusing to build additional capacity thereby raising the price for capacity. The Commission's peak/ off-peak rate policy articulated here similarly protects against this problem through the requirement that pipelines cannot recover more than their existing cost-of-service through peak/off-peak rates.

pipeline refused to build capacity, creating greater scarcity and higher prices and profits for the affiliate, which is not subject to cost-of-service limitations. This problem exists only in cases where an affiliate holds a large enough portion of pipeline capacity that the corporate entity as a whole can make more by creating scarcity than by building additional capacity and earning a rate of return on its investment.

This theoretical problem, however, exists in today's market where pipeline affiliates are able to make bundled sales not subject to a rate cap. Yet, there seems little indication that profits from scarcity exceed those that can be earned through construction, since pipeline construction applications have not noticeably declined.¹²⁶ However, because of the possibility of affiliate abuse, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, are refusing to undertake construction projects when demand for construction exists. In cases where such concerns are established, the Commission would need to take remedial measures. Depending on the circumstances, such remedies could include: requiring pipelines to put in taps to reduce capacity bottlenecks; requiring pipelines to build additional capacity when requested by customers willing to pay the costs of

¹²⁶From 1997 to October 1999, the Commission has certificated 30 major on-shore and off-shore projects, not including storage, totaling 12,594.8 MMCF/day of capacity. There are currently 13 major construction project applications, not including storage, pending at the Commission, totaling 6,440 MMcf/day of capacity. See Department of Energy/Energy Information Administration, Pub. No. DOE/EIA-0560, Natural Gas 1998 Issues and Trends, 18 (June 1999) (80 natural gas pipeline projects completed between January 1997 and December 1998).

construction; limiting the rates at which the affiliate can release capacity; limiting the amount of capacity the affiliate can hold; or prohibiting the affiliate from holding capacity on its related pipeline.

B. Peak And Off-Peak Rates

Use of peak/off-peak, or seasonal, rates for pipeline services could improve efficiency in the market place by better accommodating regulation to seasonal demand for capacity, and at the same time could benefit long-term captive customers. Therefore, as discussed below, the Commission will permit pipelines to institute peak/off-peak rates for all short-term services, i.e., short-term firm and interruptible service and multi-year seasonal contracts,¹²⁷ as one possible method of promoting allocative efficiency that is consistent with the goal of protecting customers from monopoly power. The current use of uniform maximum rates, where fixed costs are recovered in 12 monthly installments, was developed at a time when the vast majority of firm contracts were long-term contracts. The use of uniform maximum rates for long-term contracts is appropriate because, under an SFV rate design, once a shipper has committed to buy capacity for a year, the use of seasonal reservation charges will not affect the total amount the customer will pay.

¹²⁷ If a shipper contracts for capacity for certain months of the year, over a period of several years, but service is not continuous for every month of a year, the contract is similar to several short-term contracts, rather than to a long-term contract of a year or more, where the shipper purchases capacity in consecutive months during both peak and off-peak periods.

However, the use of uniform maximum prices for short-term service can create situations where short-term customers are able to purchase peak capacity at a price that may be lower than its market value while the pipeline sells off-peak capacity at "discounted" rates. If short-term customers are able to purchase peak capacity at less than its market value and off-peak capacity at a discount, while the long-term customers pay a uniform maximum rate, the short-term customers will receive annual service at a lower cost than long-term shippers. This works to the disadvantage of captive customers with long-term contracts. Further, under this scenario, short-term shippers seeking winter-only service can obtain peak period capacity for a fraction of the annual cost of providing capacity, leaving the long-term shippers responsible for the remainder. This cost allocation disparity between short and long-term shippers could increase as LDC contracts expire and more capacity is sold in the short-term market.

Peak/off-peak rates could allow pipelines to increase revenue recovery from short-term peak period shippers. Increased cost recovery from peak short-term services lessens the level of costs that need to be recovered from long-term customers and minimizes the cost shifting that occurs with off-peak discounting. By reducing the rates in the off-peak periods, peak/off-peak rates could reduce the need for discounts and reliance on discount adjustments. Many commenters¹²⁸ object to the Commission's current discount

¹²⁸See, for example, the comments of APGA, Brooklyn Union, FPL Group, Inc., Illinois Municipal Gas Agency, Mississippi Valley and Willmut Gas, NASUCA, New England Gas Distributors, Pennsylvania Office of the Consumer Advocate, Process Gas, (continued...)

adjustment policy under which pipelines offering discounts are able, in the next rate case, to adjust maximum rates to reflect the discounts. Peak/off-peak rates could better reflect the value of capacity during peak and off-peak periods, thereby reducing the need to make discount adjustments.

In addition to benefitting captive long-term customers, use of peak/off-peak rates for short-term services could better reflect the true value of capacity during peak and off-peak periods, and thus improve allocative efficiency especially during peak periods when capacity is constrained and the price in a competitive market would exceed the average maximum rate. In the current marketplace, at times when demand for capacity exceeds the available capacity, pipelines cannot automatically allocate that capacity to the shipper placing the highest value on the capacity. Instead, they must allocate capacity pro rata or on the basis of a queue. This often prevents shippers who most value capacity from obtaining it. With peak/off-peak rates the pipeline would be able to allocate that capacity more efficiently to those shippers valuing the capacity the most. Charging shippers more for use during peak periods also can provide better price signals about the need for new construction. The demand for pipeline capacity at peak is a major factor in the pipeline's decision to add to its facilities.

Thus, peak/off-peak pricing for short-term services could promote several important policy goals. It could remove one of the biases favoring short-term contracts,

¹²⁸(...continued)
and the Public Service Commission of Wisconsin.

and could lower the share of costs allocated to long-term transportation customers. It could increase efficiency in short-term markets by allowing prices to better reflect demand during peak periods. Therefore, as discussed below, the Commission will permit pipelines to implement value-based peak/off-peak rates for their short-term transportation services, within the pipeline's current cost-based revenue requirement. Under an SFV rate design, the use of peak/off-peak reservation charges for long-term contracts would not affect the total amount a long-term customer would pay over the year. Therefore, this policy will not apply to long-term contracts that are for 12 or more consecutive months of service. However, long-term customers can choose to pay peak/off-peak rates as a billing adjustment.

Rates developed under a peak/off-peak methodology will be higher at peak periods than off-peak periods. This result is the same as the result under the current uniform maximum rate method. Currently, the rates actually paid by shippers are higher during peak because the pipeline is generally able to charge the maximum rate at peak, but must discount rates during off-peak periods to customers that have alternatives available in the marketplace. Therefore, charging a higher rate during peak periods is consistent with current practice. However, peak/off-peak pricing would better match demand with price than does the current method. In allowing seasonal/peak pricing, the Commission is improving upon the existing pricing model and retaining the revenue constraints of its existing cost-based ratemaking regulatory model.

The Commission will allow the pipelines to determine the most appropriate method of implementation given the characteristics of their individual systems, consistent with the general principles discussed in this section. The Commission's discussion of peak/off-peak rates in this section, and its suggestion that pipelines voluntarily use peak/off-peak rates is a policy statement, and not a rule that imposes any requirements on pipelines or changes current Commission regulations.

1. Background

The Commission has long recognized the value of seasonal, or peak/off-peak rates, and in the NOPR sought comments on implementation of seasonal rates as one method of improving the regulatory scheme. The Commission's current regulations¹²⁹ and its precedent¹³⁰ recognize that peak/off-peak rates have a role in the ratemaking process, and the Commission has specifically recognized that differences in peak and off-peak demand may be considered in ratemaking. In the 1989 Rate Design Policy Statement, the Commission expressed concern that the derivation of rates without regard to seasonal variations in use of the pipeline does not properly ration peak capacity or lead to efficient use of the pipeline in periods of excess capacity.¹³¹ The Commission suggested that pipelines could assign peak/off-peak costs by seasonal load factors, or assign the cost of

¹²⁹18 CFR § 284.7(c)(3)(i) (1999).

¹³⁰See, e.g., Opinion No. 369, Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264 (1991); Maritimes & Northeast Pipeline, L.L.C., 80 FERC ¶ 61,346 (1997).

¹³¹Policy Statement Providing Guidance with Respect to the Designing of Rates (Rate Design Policy Statement), 47 FERC ¶ 61,295 at 62,054 (1989).

transmission facilities used to provide service above the annual load factor to the peak period.¹³²

Part 284 of the Commission's regulations has long contained the rate objectives that rates for peak periods should be designed to ration capacity and rates for off peak periods should be designed to maximize throughput.¹³³ These rate objectives are independent of the costs of providing service. Part 284 also requires that rates reasonably reflect any material variation in the cost of providing service due to whether the service is provided during a peak or non-peak period.¹³⁴ While the regulations specifically recognize the validity of seasonal rates to ration capacity, maximize throughput, and reflect cost differences, they do not limit the use of seasonal rates to these circumstances, and nothing in the Commission's regulations prohibits the use of peak/off-peak rates that reflect differences in peak and off-peak demand. Thus, peak/off-peak rates are consistent with the Commission's existing regulations, and no changes to the regulations are necessary to implement peak/off-peak rates.

The Commission recognizes that some of its prior decisions could be interpreted as limiting the use of peak/off-peak rates to circumstances where seasonal rate differences

¹³²Id.

¹³³18 CFR §284.7 (b)

¹³⁴18 CFR §284.7 (c) (3) (i)

are cost-based.¹³⁵ Although the regulations require seasonal rates to reflect seasonal cost differences, the regulations do not preclude seasonal rates designed on other bases, and the Commission has approved peak/off-peak rates using a value based method for setting peak/off-peak rates.¹³⁶ The Commission clarifies that nothing in its prior decisions was intended to limit the use of peak/off-peak rates to situations where seasonal rate differences are cost-based.

Of these two methods, basing peak/off-peak rates on value of service concepts, rather than specific costs, is more consistent with the goal of providing efficient pricing signals. Those customers that value capacity more highly should expect to pay higher prices when capacity is scarce. The prices they would be willing to pay have little relationship to the accounting cost of the facilities used to provide additional service at peak periods. In practice, it is very difficult to identify specific facilities, with the exception of storage, that are used to provide transportation service at peak periods rather than year round. A similar problem occurs on most systems if one attempts to identify specific costs that are attributable to peak/off-peak usage.

¹³⁵ See, e.g., Opinion No. 369, Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264 at 61,831 (1991) (the Commission permitted seasonalization of the sales reservation charge, but found that, based on the facts of that case, seasonalized firm rates could not be justified based on the need to ration capacity).

¹³⁶ See Maritimes & Northeast Pipeline, L.L.C., 80 FERC ¶ 61,346 (1997).

2. Implementation

The Commission will facilitate the implementation of peak/off-peak rates with a flexible policy that will permit the use of a wide variety of peak/off-peak rate methods. The pipelines can make changes in their peak/off-peak rates on a monthly basis, within existing cost of service constraints. Pipelines can implement peak/off-peak rates either through a general section 4 rate case or a pro forma tariff filing. The following discusses the basic parameters applicable to peak/off-peak filings and the procedures to be followed in processing the filings.

a. Parameters for Establishing Peak/Off-Peak Rates

Value-based peak/off-peak rates are just and reasonable cost-based rates.¹³⁷ Like uniform maximum rates, peak/off-peak rates would be established by taking the pipeline's annual revenue requirement and deriving from it a daily or monthly rate. The difference in developing peak/off-peak rates and the current uniform maximum rate is that instead of dividing the annual revenue requirement by 365 to obtain a daily rate, different daily or monthly rates will be developed for peak and off-peak periods using one of several possible methods of measuring the value of capacity at peak and off-peak.¹³⁸ The sum of the daily or monthly rates, multiplied by the quantity used or reserved, still must not exceed the pipeline's annual revenue requirement, and thus, any increases in

¹³⁷Rate Design Policy Statement, 48 FERC ¶ 61,122 at 61,446 (1989).

¹³⁸Some of these methodologies are discussed below.

rates at peak must be offset by decreases in off-peak rates. In other words, if a shipper paid the peak and off-peak rate for the same volume of transportation every day of the year, the amount it paid annually for service would be no more than if it had paid the uniform maximum daily rate for the same transportation volume based on the same revenue requirement.

This requirement limits the rate the pipeline may charge. For example, if the pipeline wanted to charge a rate greatly in excess of the current uniform maximum rate in the four month period December through March, it would have to match this increase with a corresponding reduction in rates for the remaining months. This places a check on the ability of the pipelines to propose extraordinarily high rates during peak periods because any rate increase for peak periods must be matched by a rate decrease during the off-peak periods. This is a disincentive for pipelines to raise peak period rates to unrealistically high levels since this would require an off-setting lowering of off-peak rates that could compromise the pipeline's ability to recover maximum off-peak revenues.

As illustrated by the comments, there is more than one reasonable way to implement peak/off-peak rates based on value of service concepts. The methods proposed by the commenters include using a ratio of the prices for capacity release and IT on a system to develop a ratio,¹³⁹ looking at usage of compression to develop a ratio,¹⁴⁰

¹³⁹See, e.g., comments of Amoco.

¹⁴⁰See, e.g., Comments of Columbia .

looking at peak/off-peak volumes/load factors to develop a ratio,¹⁴¹ developing a ratio based on historic price differentials between receipt and delivery point prices, or allowing a shaping of prices to try to capture the value of the capacity,¹⁴² and tailoring of contract demand levels during the year.¹⁴³ Other methods of developing peak/off-peak rates could include looking at the price at which capacity has traded, load factors, basis or other indexing, or other methods of measuring the value of capacity throughout the year. Since capacity prices are currently capped at uniform maximum rates, the historical data on pricing may not be the best indicator of the value.

Some methods may work better for certain systems than others. For example, on some systems' data may be more readily available to base peak/off-peak differences on basis differentials because the pipeline is directly connected to major market centers so that there is already considerable data on the value of the pipeline's capacity. On other systems where there is a wide swing in load factors from peak to off peak periods, a method based on load factors may make more sense.

Therefore, the best method of developing peak/off-peak rates will depend in part on the specific characteristics of each pipeline, and the Commission will not adopt any

¹⁴¹See, e.g., Comments of Columbia.

¹⁴²See comments of Texas Eastern/Algonquin, CMS Panhandle. Under this approach the pipeline would assess the relative value of capacity throughout the year and design reservation charges based on this assessment. The sum of the annual peak/off-peak reservation charges would equal the sum of the current annual average reservation charges.

¹⁴³See comments of Enron Pipelines.

one method of developing peak/off-peak rates, but will leave the details of the implementation of peak/off-peak rates to individual pipelines. The Commission will consider any reasonable method of implementation that is consistent with the general principles discussed in this section, but the pipeline will have the burden of proof to show that its proposed method is just and reasonable.

b. Process for Implementing Peak/Off-Peak Rates

The implementation of peak/off-peak rates could lead to higher pipeline revenues from short-term services since a pipeline could reduce off-peak price caps so that they would be close to recent discount history, and correspondingly increase peak price caps. The pipeline might see little or no reduction in off-peak revenues since market prices are usually below the uniform maximum price caps. Because the price cap would be higher in the peak with peak/off-peak rates, the pipeline's revenues should increase if it adopts peak/off-peak rates.

The process for implementing peak/off-peak rates, therefore, must take the increased revenues into account. One method for doing so would be for the pipeline to file a general rate case to implement peak/off-peak rates. In a general rate case, all pipeline costs and revenues can be examined and the appropriate revenue responsibility of each service can be decided. Thus, the rates for long-term services would be reduced in recognition that the pipeline could be expected to recover more revenues from short-term services.

However, the filing of general section 4 rate case may not be well-suited to this context. The Commission's rate methodology relies on a historical test period to project future throughput for each service, and revenue responsibility is assigned to each service based on those projections. There is no historical experience that would adequately project future short-term service demand with peak/off-peak pricing. Also, using general rate cases to implement peak/off-peak rates could be time consuming.

Therefore, the Commission will establish a procedure under which pipelines can establish peak/off-peak rates through a pro forma tariff filing so that the Commission and the parties will have an adequate opportunity to review the proposal prior to implementation. Under this procedure, the pro forma filing would be noticed with comments due on the pipeline's proposal within 21 days, rather than the 12 days permitted for tariff filings. The Commission would take action on the filing within 60 days. Pipelines interested in implementing peak/off-peak rates are encouraged to file proposals as soon as possible.

Consistent with the goal of benefitting long-term captive customers, if peak/off-peak rates result in the pipeline's recovering increased revenues from short-term peak services, those increased revenues should be used to offset the costs borne by long-term customers. Therefore, if the pipeline seeks to implement seasonal rates through a pro forma tariff filing, the pipeline must include in its proposal a revenue sharing mechanism that will provide for at least an equal sharing of any increased revenues with its long-term customers. The actual amount of the revenue credit can be negotiated with the pipeline's

customers before or during the pro forma tariff proceeding. After 12 months experience with peak/off-peak rates, the pipeline must prepare a cost and revenue study and file the study with the Commission. Pipelines must file the cost and revenue study pursuant to the format prescribed in § 154.313 of the Commission's regulations.¹⁴⁴ The study must be filed within 15 months of implementing peak/off-peak rates. Based on the cost and revenue study, the Commission will determine whether any rate adjustments are necessary to the long-term rates, and may order such adjustments prospectively.

As explained above, one of the policy rationales for adopting peak/off-peak rates is that under the current cost-of-service rate methodology, underpricing short-term peak capacity results in the pipeline's long-term customers paying higher rates because a greater share of the pipeline's costs are recovered from its long-term rates. The Commission is seeking to lower the rates to long-term customers in recognition of the additional risks they take by signing long-term contracts. Therefore, if a pipeline moves to peak/off-peak rates it should benefit the pipeline's long-term customers, and a revenue sharing mechanism that benefits only long-term customers is appropriate.

The Commission will not require any specific method of determining the amount of additional revenues that are attributable to implementation of peak pricing, since the same approach may not work equally well on all pipelines. The pipeline must propose a reasonable method when it files to implement peak pricing. The issues involved in

¹⁴⁴18 CFR 154.313 (1999). See Trunkline LNG Company, 82 FERC ¶ 61,198 (1998), aff'd, 194 F.3d 68 (D.C. Cir. 1999).

developing an appropriate revenue sharing mechanism may be more complex than deriving the seasonal rate itself, and these issues could be considered independently of the rate. Pipelines are encouraged to work with their customers to develop a method that has wide support. The method should be fair to the pipeline and its long-term customers and should be easy to implement. Whatever method is chosen, the pipeline is not required to share excess revenues if there really are none. A pipeline will not be required to share revenues if it demonstrates that its total revenues from peak/off-peak rates were less than the revenues allowed for the relevant services in its last rate case.

C. Term-differentiated Rates

In the NOPR, the Commission stated that one method of reducing asymmetry of risk that favors short-term contracts, and of strengthening the long-term market would be to encourage contracts that contain lower maximum rates for longer term service than for shorter term service in recognition of the value of longer term contracts in limiting the pipeline's risk. The Commission sought comments on whether and how to encourage such term-differentiated rates. Upon review of the comments, the Commission has determined that term-differentiated rates should be available to the pipeline as one of several methods that could be used to price capacity more efficiently. As explained below, the Commission will not adopt any one method of establishing term-differentiated rates , but will permit a pipeline and its customers to develop specific methodologies suitable to the characteristics of the specific pipeline in a section 4 rate proceeding.

Term-differentiated rates would match price more closely with risk-adjusted value, and could result in a rate structure that prices capacity held for a longer term at a lower rate than capacity held for a shorter term. With term-differentiated rates, maximum posted rates for longer terms would be lower than rates for shorter term service on a per unit basis and at comparable load factors. Term-differentiated rates do not differentiate between seasons, but instead, differentiate based on the length of the contract. Term-differentiated rates would more accurately reflect in the price of service the relative levels of risk that pipelines must face when selling service for a shorter period than for a longer period, as well as the higher risks that customers face when they purchase service for a longer period of time.

As the Commission explained in the NOPR, a shorter term contract is riskier for the pipeline, and a higher rate would compensate the pipeline for this additional risk. A shorter term contract provides greater flexibility and less risk to the shipper, and a higher rate would recognize and require payment for these benefits. The Commission has already recognized, in the context of oil pipeline rates, that the lower risk to the shipper and the higher risk to the pipeline, associated with shorter term contracts may properly be reflected in a higher rate for such service. In Express Pipeline Partnership,¹⁴⁵ the Commission explained that shorter term shippers have less risk because they have maximum flexibility to react to changes in their own circumstances or in market

¹⁴⁵76 FERC ¶ 61,245, reh'g denied, 77 FERC ¶ 61,188, (1996).

conditions, and are a greater risk to the pipeline because they do not provide the revenue assurances or planning assurances to the pipeline that long-term shippers do.

Several commenters¹⁴⁶ argue that term-differentiated rates are inconsistent with cost-based regulation. They argue that term-differentiated rates are not based on cost incurrence because there is no evidence that it costs more for the pipeline to meet the needs of short-term contracts. However, as explained above in the discussion of peak/off-peak rates, cost-based ratemaking is not simply a matter of strict cost incurrence. "Value and costs are inexorably linked" in ratemaking, and the Commission can legitimately consider the overall goals of its ratemaking policy in developing just and reasonable cost-based rates.¹⁴⁷ Further, the existence of long-term contracts reduces pipeline risks and therefore lowers its cost of capital.

Like peak/off-peak rates, term-differentiated rates would be cost-based, just and reasonable rates because the Commission will limit the rates in the aggregate to produce the pipeline's annual revenue requirement. The difference between developing constant average rates and term-differentiated rates is that instead of establishing a single rate cap for each service, as in current practice, with term-differentiated rates, different rates would be charged to different customers based on the length of their contract.

¹⁴⁶See, for example, comments of Dynegy, Amoco, and Indicated Shippers/

¹⁴⁷Interstate Natural Gas Pipeline Rate Design, 48 FERC ¶ 61,122 at 61,446 (1989).

There are various methods that could be used to develop reasonable term-differentiated rates. For example, in its comments, INGAA suggested that term-differentiated rates could be developed using a cost allocation approach that would allocate costs between shorter term and longer term service based on an allocation factor such as projected percentages of throughput.

Several commenters¹⁴⁸ asserted that the Commission should not approve term-differentiated rates as a ratemaking option without setting forth a specific proposal for comment in a generic proceeding. However, the Commission has concluded that since there is more than one appropriate method of establishing term-differentiated rates, and some methods might be more appropriate on certain pipelines than on others, it will not limit the pipeline to one method, but will allow the pipelines and the customers to work out the details of the methodologies in specific rate proceedings.

A pipeline may propose term-differentiated rates just for long-term services or for both short and long-term services. The Commission recognizes that the use of term-differentiated rates for short-term services may enhance the potential for price discrimination, particularly during off-peak periods, by increasing the rate caps that would apply to short-term service acquired in off-peak periods. Consequently, a pipeline proposing term-differentiated rates for short-term services will need to fully explain the basis and justification for the price differentials.

¹⁴⁸See, for example, comments of Process Gas Consumers.

Term-differentiated rates have a much greater potential for effecting the rates of all customers than peak/off-peak rates. Term-differentiated rates would raise the maximum tariff rates for some customers, and there should be a decrease in the maximum tariff rates for long term customers. The general reallocation of revenue responsibility among customer classes must be done through rate changes for all customers simultaneously in the section 4 rate filing in which the pipeline seeks to implement term-differentiated rates.

D. Voluntary Auctions

Auctions, if properly designed, can provide for efficient allocation of capacity and natural gas, reduce transaction costs in finding and arranging capacity transactions, and provide for more accurate dissemination of relative pricing information to the marketplace. Auctions also can be used as methods of mitigating the effects of market power by limiting the ability of sellers to withhold capacity, to price discriminate, or to show favoritism. With the growth of the Internet, electronic auctions have become an effective and efficient method of exchanging goods and services. Auctions increasingly are being used successfully in energy industries. Electronic auctions have been established to facilitate exchanges of gas. Auctions similarly are being used in the electric industry to allocate generation and transmission capacity. Pipelines have been using electronic open seasons to determine demand for new construction. The capacity release posting and bidding system itself is a form of auction.

A number of commenters recognize the potential value in the use of auctions, but urge the Commission and the industry to obtain greater familiarity with the use of

auctions in order to obtain better understanding of the auction formats that work well and those that do not. Although the Commission is not moving forward with mandatory auctions for pipeline capacity as well as short-term released capacity at this time, the Commission is still of the view that more extensive use of auctions can provide a wide range of benefits to the gas industry. Pipelines are encouraged to file proposals for implementing auctions and this section discusses principles for evaluating such proposals. Third-parties also encouraged to develop capacity auctions, and, as discussed below, the Commission, in appropriate circumstances, may be willing to modify certain regulatory requirements to facilitate such auctions.

The existing third-party auctions for natural gas, for instance, may form the basis for the development of an efficient auction for transportation capacity or one that would combine the gas commodity and transportation capacity within a single auction format. Such auctions could resolve one of the objections to capacity-only auctions: that capacity-only auctions would force buyers to obtain capacity, without knowing whether they would be able to obtain gas at a reasonable price.¹⁴⁹ Pipelines also may find it efficient to use a form of auction to allocate short-term capacity on a monthly, daily, or even intra-day basis. As a result of restructuring under Order No. 636, most pipeline tariffs require that interruptible capacity be allocated based on price when the pipeline is unable to fulfill

¹⁴⁹See Comment of Dynegy. Dynegy was concerned that if a shipper obtained capacity and then had to negotiate for gas, the gas producer would obtain leverage in the transaction, because the shipper had already committed to pay for capacity from a particular receipt point.

all nominations for service.¹⁵⁰ The use of a more formal auction method, therefore, may be a reasonable method of allocating capacity.

The Commission also encourages pipelines and third-parties to consider establishing multi-pipeline or regional auctions. Such auctions could eliminate concerns expressed in the comments about possible difficulties in using auctions on individual pipelines to acquire a capacity path traversing multiple pipelines.¹⁵¹ Pipelines in a region, for instance, could arrange with a third-party auctioneer to sell the pipelines' available capacity in the same auction as capacity release transactions in that region, thereby providing shippers with one-stop capacity shopping.

The Commission recognizes that some of its existing regulations may impede the development of auctions. For instance, Altra has identified the requirement that all capacity release transactions must be posted for bidding on pipeline Internet sites as a potential barrier to third-party auctions, because it would require the double posting of capacity: once on the third-party's auction mechanism and a second time on the pipeline's Internet site. The Commission also has required, and, in this rule is continuing to require, the publication of the names of shippers acquiring capacity from releasing shippers and the pipeline in order to provide price transparency and to permit effective monitoring of

¹⁵⁰See *Sea Robin Pipeline Company*, 81 FERC ¶ 61,041, at 61,225 (1997); *Pacific Gas Transmission Company*, 76 FERC ¶ 61,258 (1996).

¹⁵¹See *Comments of Process Gas Consumers I, Wisconsin Distributors, Nicor Gas, PG&E, Shell Energy Services*.

potential undue discrimination. In a properly designed auction, however, the requirement for posting the winning bidder's name may not be necessary, so long as the market price is disclosed. A waiver of the requirement to post the winning bidder's name, or to delay such posting, could be granted when the auction is designed in such a way that shippers can verify that the auction was properly conducted and the winning bid awarded fairly without favoritism.¹⁵² Upon application by a third-party or pipeline, the Commission would consider waiving these or other regulatory requirements that unnecessarily impede the development of auctions. Pipelines, however, may need to continue to post the results of affiliate transactions unless they can demonstrate that the format of the auction and the results are designed in such a way as to preclude affiliate favoritism. The use of third-party auctioneers or certification may be methods of providing sufficient security against affiliate abuse.

An auction also may be a means by which a pipeline could sell some or all of its capacity without a price cap if the auction is designed in such a way as to protect against the pipeline's ability to withhold capacity and exercise market power. Not all types of capacity would have to be allocated through the auction process. For example, the pipeline may have a reasonable basis for limiting the auction only to short-term firm or interruptible capacity. The Commission also still sees value in permitting the pipelines to negotiate prearranged deals while they conduct auctions for remaining capacity, although,

¹⁵²For instance, the use of an independent firm to verify the results of the auction may be sufficient without the posting of winning shippers' names.

as discussed below, pipelines must not withhold available capacity from the auction simply because they believe a better pre-arranged deal may be arranged in the future.

Once capacity is placed in the auction, the pipelines must design the auction in ways to prevent the withholding of capacity and the exercise of market power. Capacity can be withheld by a pipeline in two primary ways: the pipeline can withhold capacity directly by not putting it into the auction; or it can indirectly withhold capacity through the use of a reserve price. In a proposal for auctions without a rate cap, all capacity available at that time of the auction would have to be included in the auction. The auction proposal also needs to address the appropriate limitations that should be placed on the level at which the pipeline can establish reserve prices, particularly whether different reserve prices should be established for peak and off-peak capacity.

While the Commission will not insist on any particular auction format for pipelines or third-parties, the Commission sets forth below some basic principles to which auctions should adhere:

- The timing of the auction should be predictable, and shippers potentially offering or bidding on capacity should have notice of when the auction will be held and what capacity will be included.
- The auction should be open to all potential bidders on a non-discriminatory basis.
- The auction should be user-friendly with information on the rules and procedures easily accessible to all.
- The bidding procedures as well as the methods for selecting the best bid should be fully disclosed prior to the auction. For instance, if not present

values formulas are used, the discount rate and the method of calculation should be disclosed.

- There should be no favoritism in the determination of the winning bidder and mechanisms should be included to permit monitoring of how the selection criteria were applied. This would include methods of verifying any reserve price applied in an auction.
- Transaction information (such as prices, volumes, and receipt and delivery points) should be disclosed so that shippers can ascertain the value of transportation. The names of shippers may not need to be disclosed or could be disclosed at a later date if the auction results are verifiable and free from potential affiliate favoritism.

Adherence to these principles should help to ensure that auctions are transparent, verifiable, and non-discriminatory. The Commission strongly encourages pipelines and third-parties to begin the development of auction formats so that the industry will gain greater experience and familiarity with the use of auction techniques. Toward that end, Commission staff will be available to assist pipelines or third-parties in their development of auction formats.

III. IMPROVING COMPETITION AND EFFICIENCY ACROSS THE PIPELINE GRID

The Commission in this rule is making changes to enhance competition and improve efficiency across the pipeline grid. By improving efficiency and shipper options, these changes should provide shippers with market mechanisms that will better enable them to avoid market power where it exists. The changes include revising Commission regulations to: require pipelines to revise their scheduling procedures so that capacity release transactions can be scheduled on a comparable basis with other pipeline services;

require pipelines to permit shippers to segment capacity and to facilitate capacity release transactions; and require pipelines to offer services that shippers can use to avoid penalties and to provide shippers with additional information that will enhance their ability to avoid penalties. Pipelines must file pro forma tariff sheets to comply with these requirements by May 1, 2000. Interested parties will be provided 30 days to comment on the pro forma tariff filings.

A. Scheduling Equality

The Commission is adopting in this final rule, the proposal set forth in the NOPR to amend its regulations to include a new section 284.12(c)(1)(ii) to provide that pipelines must provide purchasers of released capacity the same ability to submit a nomination at the first available opportunity after consummation of the deal as shippers purchasing capacity from the pipeline. This will enable shippers to acquire released capacity at any of the nomination or intra-day nomination times, and nominate gas coincident with their acquisition of capacity. By enabling released capacity to compete on a comparable basis with pipeline capacity, this will foster a more competitive short-term market.

In the NOPR, the Commission explained that the current regulations put capacity obtained in the release market at a disadvantage compared to capacity obtained directly from the pipeline because nomination and scheduling opportunities for capacity release transactions are significantly circumscribed. As the Commission explained, pipelines can sell their interruptible and short-term firm capacity at any time, and shippers can schedule that capacity at the earliest available nomination opportunity. Further, shippers

purchasing from the pipeline have three opportunities for intra-day nominations.¹⁵³

Similarly, capacity holders making delivered sales can nominate and schedule at every available opportunity. By contrast, shippers utilizing released capacity must consummate their deals by 9:00 AM in order to submit a nomination by 11:30 AM to take effect at 9:00 AM the next gas day, and they cannot use an intra-day nomination opportunity to submit a nomination for the current gas day.

In order to place capacity release transactions on a more equal footing with pipeline services, the Commission is amending its regulations to include a new section 284.12(c)(1)(ii) to provide that pipelines must provide purchasers of released capacity, like shippers purchasing capacity from the pipeline, with the opportunity to submit a nomination at the first available opportunity after consummation of the deal. The regulation specifically provides that the contracting process should not interfere with the ability of the replacement shipper to nominate at the time the transaction is complete. In the NOPR, the Commission explained that there are several ways that a pipeline can protect itself, and suggested that pipelines can institute procedures under which replacement shippers receive pre-approval of their credit-worthiness or receive a master contract, such as those given to interruptible shippers, permitting the replacement shipper to nominate under the contract at any time. The Commission will not require any specific

¹⁵³Standards for Business Practices of Interstate Natural Gas Pipelines, Final Rule, 63 FR 39509 (July 23, 1998), 84 FERC ¶ 61,031 (1998).

method of compliance with this regulation, but will allow the pipeline to develop procedures suitable for its system.

The vast majority of the commenters fully supported the Commission's proposal.¹⁵⁴ These parties agree that providing replacement shippers with the same opportunities to nominate gas as the shippers nominating primary capacity will promote more competitive markets and help mitigate the pipeline's market power. For example, Dynegy characterizes the Commission's proposal as a "common sense adjustment" that will pave the way to more competitive markets and mitigate pipeline market power.

Several of the commenters asked the Commission to clarify the bumping right of replacement shippers in view of the new procedures.¹⁵⁵ For example, Industrials state that it seems clear that a replacement shipper should have the same bumping rights as any firm shipper vis-a-vis an interruptible shipper, but that the question of whether a replacement shipper should be able to bump secondary firm if the replacement shipper has primary firm is more difficult, and the Commission should clarify the entire issue of intra-day bumping of secondary firm by primary firm.

¹⁵⁴For example, AEC Marketing, AF&PA, AGA, Amoco, Atlanta Gas Light, Colorado Springs, Columbia LDCs, Consolidated Natural, Duke Energy Trading, Exxon, Florida Cities, FPL Group, IPAA, Indicated Shippers, Louisville, Market Hub Partners, MichCon, Midland, NARUC, NEMA, NGSA, New England Gas Distributors, PanCanadian, Philadelphia Gas Works, Process Gas Consumers, et al., Proliance, PSC of Kentucky, PSC of New York, PSC of Wisconsin, Sithe, Washington Gas Light, and Wisconsin Distributors.

¹⁵⁵For example, see the comments of Industrials, New York Public Service Commission, and NGSA.

Nothing in the revised regulation adopted here changes the current rules on bumping, and the bumping rules in effect on each pipeline will remain unchanged and will continue to govern the priorities among shippers. A replacement shipper would, as a firm shipper, bump an interruptible shipper, subject to the requirement of notice to the interruptible shipper and an opportunity to renominate.¹⁵⁶ Generally, primary firm will not interrupt secondary firm on an intra-day basis once the gas has begun to flow, but again that rule is pipeline-specific, and will be governed by the particular pipeline's tariff.¹⁵⁷

Some of the commenters suggested procedural changes which they state would expedite the execution of an agreement between the pipeline and the replacement shippers where such an agreement is required by the pipeline. For example, Dynegy suggests that the Commission require pipelines to adopt a master pro forma capacity release service agreement, or an umbrella agreement, that would include pre-approved credit, upon which replacement shippers can aggregate released capacity.

The regulation adopted by the Commission specifically provides that if the pipeline requires the replacement shipper to enter into a contract, "the requirement for contracting must not inhibit the ability to submit a nomination at the time the transaction is complete." The Commission suggested in the NOPR several methods, including the

¹⁵⁶E.g. Tennessee Gas Pipeline Corporation, 73 FERC ¶ 61,158 (1995).

¹⁵⁷See El Paso Natural Gas Company, 81 FERC ¶ 61174 at 61,763 (1997).

type of procedure suggested by Dynegy, that pipelines could use to meet this requirement. The Commission will not mandate any one method, but will leave this to be resolved by the pipelines and shippers.

Dynegy argues the Commission should, in this proceeding, require all restrictions on capacity release to be removed. For example, Dynegy states that releasing shippers should be given the same rights as pipelines to sell capacity for less than a day. Further, Dynegy states that certain pipelines place other restrictions on released capacity, such as refusing to continue a discount if the capacity is released, requiring additional paperwork for capacity releases, requiring releasing shippers to remit to the pipeline any amounts received from the replacement shipper in excess of the releasing shipper's discounted rate, and requiring a deposit every time a capacity release bid is submitted.

Dynegy's concerns about discounting have been resolved by the Commission in prior proceedings. The Commission has specifically held that a discount cannot be conditioned on an agreement not to release the capacity, and a pipeline cannot refuse to continue a discount if capacity is released.¹⁵⁸ Further, Order No. 636-A specifically provides that "a releasing shipper paying discounted rates is entitled to receive the proceeds from a release even if such proceeds exceed its reservation fee."¹⁵⁹ The Commission has recognized an exception to this general rule only if the pipeline and the

¹⁵⁸ Natural Gas Pipeline Co., 84 FERC ¶ 61,099 (1998).

¹⁵⁹ Order No. 636-A, FERC Stats.& Regs. ¶ 30,950 at 30,562 (1992).

releasing shipper negotiate a revenue sharing agreement that is approved as part of a general section 4 rate proceeding or specifically approved as a non-conforming discount agreement.¹⁶⁰

In addition, there is no basis for a pipeline to charge a deposit every time capacity is released. Under the new regulation adopted here, as well as under GISB Standard 5.3.2, the pipeline must approve a contract within an hour, and therefore will know before gas flows under the release whether the replacement shipper is creditworthy. If the replacement shipper is creditworthy, then there is no basis for requiring a bond. The only time this issue would arise is when the replacement shipper is determined not to be creditworthy. In these circumstances, the pipeline could give the releasing shipper the option of posting a bond for the usage charge or assuming liability for the usage charge in the event of the replacement shipper's default.

Some of the other problems cited by Dynegy, such as additional paperwork for capacity release, should be alleviated by the rule adopted here. Creating equality in nominations for capacity release will foster a more competitive market. However, the Commission has recognized that some of the differences in the treatment of different types of capacity reflect differences in the nature of the services that should be preserved. The Commission is not prepared to say at this time that all differences in the treatment of capacity release are unwarranted and should be eliminated.

¹⁶⁰Natural Gas Pipeline Co., 82 FERC ¶ 61,289 (1998); 84 FERC ¶ 61,099 (1998).

INGAA and Enron Pipelines argue that the different treatment of capacity release does not result from a lack of nomination opportunities, but stems from the deadline by which shippers currently must complete capacity release transactions. INGAA suggests that the problem could be solved by not requiring pre-posting and bidding for capacity release transactions. If the Commission does not accept this proposal, INGAA states that it would support revisions to the standard capacity release timeline to permit capacity release transactions to be conducted in the morning before the timely nomination deadline, rather than requiring such transactions to close on the day before nominations. INGAA states that an updated timeline is a better approach than setting a one-hour contracting requirement.

The rule adopted here will speed up the capacity release nomination process for pre-arranged deals, but the Commission will not change the requirement for posting and bidding for longer deals. Posting and bidding is necessary to continue to protect against undue discrimination, and where capacity release is for a period of a month or longer, posting and bidding should not interfere with execution of the contract.

The Coastal Companies state that while they do not oppose the goal of achieving parity between pipeline capacity and release capacity, they believe that the Commission's proposal will create additional unnecessary burdens on pipelines and shippers. Coastal states that, contrary to the Commission's assumption, shippers do not avoid capacity release, but instead seek out the capacity release market in order to maximize flexibility and minimize disclosure. They state that their companies are already handling release

transactions expeditiously. Specifically, they state that ANR already has in its tariff a master agreement for replacement shippers to utilize, and CIG and WIC create a contract immediately at the time of the award. If the Commission does mandate these changes, the Coastal Companies ask the Commission to permit the pipelines to submit limited section 4 filings in order to recoup the costs associated with the mandated procedures.

Contrary to the assertion of the Coastal Companies, the comments received by the Commission on this issue indicated a general consensus that current restrictions on nominations and scheduling of capacity release do inhibit the use of release capacity, and that the Commission's proposal will alleviate this problem. If the Coastal Companies already expedite capacity release agreements and use a master contract, they should not have to make any significant changes in their procedures, and implementation should not be burdensome to them.

Finally, some commenters¹⁶¹ have asked that the Commission eliminate the "shipper must have title" policy. For example, AGA asserts that the Commission should consider repeal of the policy because the market has changed since issuance of Order Nos. 436 and 636. Several other commenters ask that the Commission consider waivers of the shipper must have title policy for LDCs.¹⁶²

¹⁶¹See, for example, comments of AGA, Atlanta Gas Light, Edison Electric, Brooklyn Union, Atlanta Gas Light Co.

¹⁶²See, for example, comments of Columbia LDCs, Shell Energy, and ConEd.

The shipper must have title policy developed in the individual pipeline proceedings to implement open access transportation under Order No. 436, and was intended to assure nondiscriminatory access to transportation.¹⁶³ Thus, the policy predates the Commission's capacity release program established in Order No. 636, but the capacity release rules were designed with this policy as their foundation. For example, the rules are designed with all transactions conducted through the pipeline, with each shipper who acquired capacity contracting with the pipeline.

Under the capacity release rules, all allocations of capacity must be nondiscriminatory. The current regulations are designed to assure the transparency of capacity release transactions and thereby assure that capacity is allocated on a non-discriminatory basis. The regulations are also designed to assure that capacity is allocated to the highest bidder and thereby promote efficient pricing of capacity. Without the shipper must have title policy, it is unlikely that shippers would need to use capacity release because capacity holders could simply transport gas over the pipeline for another entity. These transactions would not be subject to any of the capacity release requirements, such as the reporting requirements or the allocation rules. Without the shipper must have title rule, the identity of the users of the pipeline's transportation and the conditions under which they moved gas would not be known.

¹⁶³E.g., Consolidated Gas Transmission Corp., 38 FERC ¶ 61,150 at 61,408 (1987)("all shippers shall have title to the gas at the time the gas is delivered to the transporter and while it is being transported by the transporter"); Texas Eastern Transmission Corporation, 37 FERC ¶ 61,260 at 61,683-85 (1986)).

It is possible that the Commission could revise the capacity release program so that it could operate without the shipper must have title policy and still achieve the objectives of nondiscriminatory, efficient allocation of capacity with transparency. However, this would require major revisions to the current capacity release regulations, and such a change is not within the scope of this proceeding. The Commission recognizes that the current policy may impose some transaction costs, but this is necessary to ensure the ability to achieve the Commission's regulatory objectives.

The Commission would consider any such changes to the capacity release program in a separate proceeding at a later date.

B. Segmentation and Flexible Point Rights

In Order No. 636, the Commission established two principles -- flexible point rights and segmentation -- that are important to creating efficient competition in the market, both between shippers releasing capacity and the pipeline as well as between releasing shippers.¹⁶⁴ Flexible point rights refer to the rights of firm shippers to change receipt or delivery point so they can receive and deliver gas to any point within the firm capacity rights for which they pay. Segmentation refers to the ability of firm capacity

¹⁶⁴Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,939, at 30,428, 30,420-21 (Apr. 8, 1992), Order No. 636-A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996] ¶ 30,950, at 30,559 n.151 (Aug. 3, 1992), Order No. 636-B, 61 FERC ¶ 61,272, at 61,997 (1992).

holders to subdivide their capacity into segments and to use the segments for different capacity transactions.

The ability to use flexible receipt and delivery point rights and to segment capacity enhances the value of firm capacity and the ability of firm capacity holders to compete with capacity available from the pipeline as well as capacity available from other releasing shippers. In the example used in Order No. 636, a shipper holding firm capacity from a primary receipt point in the Gulf of Mexico to primary delivery points in New York could release that capacity to a replacement shipper moving gas from the Gulf to Atlanta while the New York releasing shipper could inject gas downstream of Atlanta and use the remainder of the capacity to deliver the gas to New York. In order for such a transaction to work, both the releasing and replacement shippers need the right to change their receipt and delivery points from the primary points in their contracts to use other available points.

The combination of flexible point rights and segmentation increases the alternatives available to shippers looking for capacity. In the example, a shipper in Atlanta looking for capacity has multiple choices. It can purchase available capacity from the pipeline. It can obtain capacity from a shipper with firm delivery rights at Atlanta or from any shipper with delivery point rights downstream of Atlanta. The ability to segment capacity enhances options further. The shipper in New York does not have to forgo deliveries of gas to New York in order to release capacity to the shipper seeking to deliver gas in Atlanta. The New York shipper can both sell capacity to the shipper in

Atlanta and retain the right to inject gas downstream of Atlanta to serve its New York market.

The Commission's segmentation policy was not included in the Commission's regulations. Moreover, the segmentation policy is not being uniformly implemented across the pipeline grid. Some pipelines may not permit segmentation at all or may only permit segmentation for release purposes, but not by the shipper for its own uses. In order to improve competition, the Commission is requiring pipelines to permit shippers to segment their capacity for their own use or for release to the extent operationally feasible.

Another issue raised in the NOPR concerned the Commission's policy with respect to relative priorities for shippers to use secondary points within their path and for confirmations at points of interconnection between pipelines. On these issues, the Commission has determined that a generally applicable regulation is not appropriate and that these issues are best handled on a case-by-case basis.

The Commission addresses below its determinations with respect to segmentation and with respect to relative priorities for shippers using secondary points and at points of pipeline interconnection.

1. Segmentation Policies

In the NOPR, the Commission sought comment on whether further regulatory change in its segmentation and flexible receipt and delivery point policies are needed to enhance competition. The Commission pointed out that the segmentation policy adopted in Order No. 636 applied to capacity release transactions and that the Commission had

not required pipelines to permit shippers to segment capacity for their own use. The Commission further sought comment on limitations on the ability to use flexible receipt and delivery points in segmented releases that had been accepted in pipeline restructuring proceedings under Order No. 636.

In some restructuring proceedings, the Commission permitted pipelines to restrict replacement shippers' ability to choose primary points based on historic tariff provisions that limited primary point rights to the same level as the shipper's mainline contract demand.¹⁶⁵ But even at that time, the Commission questioned whether those restrictions were justified.¹⁶⁶ Although the Commission accepted the restrictions, the Commission also sought to minimize the effect of the restrictions on the ability to engage in segmented releases by permitting releasing and replacement shippers in segmented releases to choose separate primary point rights. The Commission found that because the releasing and replacement shippers were both shippers on the system, they should both be able to choose primary points consistent with their mainline contract demand:

The releasing and replacement shippers must be treated as separate shippers with separate contract demands. Thus, the releasing shipper may reserve primary points on the unreleased segment up to its

¹⁶⁵Compare Transwestern Pipeline Company, 62 FERC ¶ 61,090, at 61,659, 63 FERC ¶ 61,138, at 61,911-12 (1993); El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,982-83 (1993) (permitting pipelines to continue historic limitations on primary receipt point rights) with Northwest Pipeline Corporation, 63 FERC ¶ 61,124, at 61,806-08 (1993) (not permitting the pipeline to add such restrictions).

¹⁶⁶Transwestern Pipeline Company, 62 FERC ¶ 61,090, at 61,659, 63 FERC ¶ 61,138, at 61,911-12 (1993).

capacity entitlement on that segment, while the replacement shipper simultaneously reserves primary points on the released segment up to its capacity on that segment.¹⁶⁷

Under this Texas Eastern/El Paso approach, the releasing shipper could protect its New York delivery point right by choosing Atlanta as its primary receipt point and New York as its primary delivery point, while the replacement shipper designated its primary receipt point as the Gulf and Atlanta as its primary delivery point. In this example, neither releasing nor replacement shipper held contract demand in excess of their mainline rights. In other cases, where historic contract demand restrictions did not apply, the Commission allowed replacement shippers in all circumstances to change primary points without the releasing shipper losing its primary point rights.¹⁶⁸

Most shippers strongly support the ability to segment capacity and to use flexible receipt and delivery points to enhance competition throughout the pipeline grid.¹⁶⁹ They contend that pipelines' implementation of segmentation policies vary, with some pipelines permitting no segmentation at all and with little consistency in the way pipelines treat segmented releases. Dynegy contends that differences in segmentation policy among

¹⁶⁷Texas Eastern Transmission Corporation, 63 FERC ¶ 61,100, at 61,452 (1993); El Paso Natural Gas Company, 62 FERC ¶ 63,311, at 62,991. See also Transwestern Pipeline Company, 61 FERC ¶ 61,332, at 62,232 (1992).

¹⁶⁸See Northwest Pipeline Company, 63 FERC ¶ 61,124, at 61,806-08 n.72 (1993).

¹⁶⁹See Comments of AlliedSignal, AFPA, AGA, Columbia LDCs, Duke Energy Trading, Dynegy, Fertilizer Institute, IPAA, Market Hub Partners, Midland, NEMA, New England Distributors, NGSA, Nicor, PanCanadian, PSC of Wisconsin, Sithe, and Wisconsin Distributors.

pipelines has made it difficult to compete effectively on certain pipelines. It points out, for example, that on some pipelines, shippers can segment their capacity through the nomination process while other pipelines restrict segmentation to capacity release transactions, forcing shippers to release capacity to themselves in order to segment capacity. The shippers urge the Commission to clearly establish and standardize its segmentation policy.

INGAA supports the Commission's objective of implementing workable segmentation policies that broaden shippers' opportunities and increase competition. INGAA cautions, however, that any segmentation policy must be cognizant of the wide differences in pipeline configurations, some of which are less conducive to segmentation than others.¹⁷⁰ INGAA also recommends that the Commission adhere to its policy recently enunciated in Tennessee¹⁷¹ that shippers do not have a right to release overlapping segments or to have the releasing and replacement shippers submit nominations that would have the effect of exceeding the contract demand of the original contract on any segment of the pipeline.

Shippers generally support a policy of permitting replacement shippers maximum flexibility to choose primary points in a segmented release that differ from those of the releasing shipper. In particular, they support the Texas Eastern/El Paso policy under

¹⁷⁰See also Comments of Coastal, Koch, National Fuel.

¹⁷¹Tennessee Gas Pipeline Company, 85 FERC ¶ 61,052 (1998).

which, in a segmented release, the replacement shipper is considered a new shipper who can choose primary receipt and delivery points from among the points available.¹⁷² Some also support the position that, if a replacement shipper changes primary points, a releasing shipper should be able to regain its primary points after the release ends.¹⁷³ The pipelines generally oppose allowing segmented releases to expand primary receipt and delivery point rights on their systems or to permit the releasing and replacement shipper to hold more primary point capacity than the releasing shipper initially held.¹⁷⁴ Koch maintains that while the Texas Eastern/El Paso policy would work on some pipelines, it would not work on its system which is a reticulated or cancellated network without defined paths.

Although the Commission sought to ensure consistency during the restructuring proceedings under Order No. 636, the comments demonstrate that segmentation rights have not been implemented consistently across the pipeline grid. Accordingly, the Commission is adopting a regulation in new section 284.7 (e) stating:

An interstate pipeline that offers transportation service under subpart B or G of this part must permit a shipper to make use of the firm capacity for which it has contracted by segmenting that capacity into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible.

¹⁷²See Comments of AFPA, AGA I, Amoco I, Consolidated Natural, National Fuel Gas Distribution, New England Distributors, Proliance, Reliant Energy, Sithe.

¹⁷³See Comments of AGA I, Florida Cities, MichCon, Proliance, National Fuel Gas Distribution, and Sithe.

¹⁷⁴See Comments of INGAA.

This regulation will help achieve a more uniform and systematic application of segmentation rights across the interstate pipeline grid. Requiring pipelines to permit shippers to segment their capacity will increase the number of alternative capacity sources and therefore improve the competitiveness of the pipeline grid. The regulation further ensures a shipper's right to segment capacity for its own use as well as for release transactions. This will eliminate the inefficiencies present in the current system, such as shippers having to release capacity to themselves in order to segment their own capacity.¹⁷⁵

Providing for more effective segmentation also is important in facilitating the development of market centers and liquid gas trading points. Without the ability to segment capacity, a shipper with firm-to-the-wellhead capacity on a long-line pipeline has an incentive to obtain gas from an upstream production area attached to the long-line pipeline, rather than at a downstream interconnect with another pipeline. Because the firm shipper has paid for upstream transportation in its demand charge, the shipper has to pay only a small usage charge to move gas from the production area to the shipper's delivery point. In contrast, if the shipper or its gas supplier does not hold firm capacity on the connecting pipeline, they would have to pay additional transportation charges for interruptible service or released capacity to move gas along the connecting route to the interconnect point. For example, if the price for gas at the upstream production area on

¹⁷⁵See Comment of Dynegy.

the long-line pipeline is \$2.00/MMBtu and the delivered gas price at the interconnect point is \$2.15/MMBtu (with an implicit transportation value of \$.15/MMBtu) and the firm shipper's usage charge is less than \$.01/MMBtu, the shipper would save \$0.14/MMBtu by purchasing gas at the upstream production area, rather than at the interconnect point.

Capacity segmentation, however, permits the shipper to release its capacity upstream of the market center for the market-determined value while retaining capacity downstream of that point in order to transport gas to market. In the prior example, the firm shipper's ability to release its upstream capacity for the market-determined value of \$.15/MMBtu would permit it to purchase gas for \$2.15/MMBtu at the interconnect without suffering an economic loss. Segmentation, therefore, reduces the economic incentive to favor the pipeline on which the shipper holds firm capacity, making the development of a market center or gas trading point at the interconnect point more viable.

The regulation provides that segmentation must be permitted to the extent operationally feasible. This recognizes that, as INGAA points out, the configurations of some pipelines may make segmentation more difficult because these pipelines do not always provide straight-line paths. But the Commission expects a pipeline to permit segmentation to the maximum extent possible given the configuration of its system. Pipelines also need to make the process of segmentation as easy as possible, for example, by permitting segmentation to take place quickly and efficiently through the nomination process.

Pipelines will be required to make a pro forma tariff filing by May 1, 2000, showing how they will comply with this regulation. That filing must include whatever tariff changes are necessary for full compliance with the regulation or an explanation of how the pipeline's current tariff meets the requirements of the regulation. Pipelines claiming that all or any parts of their systems do not permit complete segmentation must demonstrate in their compliance filing why they must limit segmentation either to ensure service to other shippers or to ensure the operational integrity of their systems. Pipelines that are reticulated only in some portions of their system must permit full segmentation on the non-reticulated portion.

In the compliance filings, pipelines must provide operational justifications for restrictions on segmentation rights. As discussed above, some pipelines imposed restrictions on segmentation during the restructuring proceedings under Order No. 636 based on historic provisions in their tariffs. However, many of these historic tariff provisions date back to the pipelines' provision of merchant service and may no longer be justified for open access service provided in a more competitive market environment. In ruling on compliance filings, the Commission will not accept limitations on segmentation rights based solely on existing tariff conditions. Pipelines need to provide operational justifications for restricting the rights of shippers to effectively segment capacity and use flexible receipt and delivery points and must justify a proposal to deviate from the Texas Eastern/El Paso policy with respect to assignment of primary receipt and delivery points between releasing and replacement shippers.

2. Priorities for Capacity Within a Path

In Order No. 636, the Commission required pipelines to permit shippers to change receipt and delivery points or to use any receipt or delivery point within the zone for which the shipper pays as a secondary point with a priority greater than interruptible capacity. When pipelines implemented Order No. 636, they assigned priorities to the types of services they provide. The general practice was to accord the highest priority to capacity at primary points. Shippers using secondary points receive equal priority regardless of where their primary points are located in the zone, because the shippers are paying the same zone rate: shipper A, with a primary point upstream in the zone, has the same right to deliver to a downstream point in that zone as Shipper B with a primary point further downstream in the zone, even though shipper B's path goes past the secondary point, and shipper A's path does not. Thus, if the pipeline cannot serve all the nominations to secondary points, each shipper will receive a pro rata allocation of capacity. Interruptible capacity is assigned the lowest value.

A number of shippers contend that the Commission should adopt a regulation requiring that pipelines provide a shipper that is using a secondary point within its path a higher priority than a shipper in the same zone using a secondary point outside of its path (path approach).¹⁷⁶ Dynegy argues that where constraints occur, a shipper using a secondary point within its path may lose capacity because the pipeline curtails all

¹⁷⁶See Comments of Dynegy, Enron Capital & Trade, Indicated Shippers, NEMA, National Fuel Gas Distribution, PanCanadian, PSC of Wisconsin, and Sithe.

secondary point nominations equally even though the pipeline could make a delivery to that secondary point. Dynegy contends that often the shipper with the priority path can still reach the upstream secondary point, but that it may have to pay the pipeline a fee for a backhaul to do so. Some pipelines also have proposed to provide higher priority to shippers within a primary path.¹⁷⁷ Koch and National Fuel, on the other hand, maintain that on their reticulated systems, shippers often do not have capacity paths and that, therefore, there cannot be a distinction between in-path and out-of-path secondary points.

The Commission has decided not to adopt the path approach as a generic policy. Providing priority to shippers within the path is not necessarily a more efficient allocation method than treating all shippers who pay the same rate equally. Capacity allocation is the most efficient when the capacity is allocated to the person placing the highest value on the capacity. In a perfect competitive environment, without transaction costs, the initial allocation of capacity among shippers will not matter because, through trading, capacity can be allocated to the highest valued user. Where transaction costs do exist, the goal of allocation should be to make the initial allocation to the party placing the highest value on obtaining the service in question. However, when dealing with the allocation of capacity to secondary points, there is no reason to believe that a shipper with a downstream primary delivery point necessarily places greater value on using a secondary

¹⁷⁷Panhandle Eastern Pipe Line Company, 87 F.E.R.C. ¶ 61,331 (1999).

point in the zone than a shipper paying the same rate with an upstream primary delivery point.

The real problem in allocating secondary receipt or delivery points in constraint situations is not with initial priority allocations, but with the pricing structure on pipelines. Pipelines charge all shippers within a zone the same rate even though many pipelines do not divide zones along constraint points: a single zone encompasses points upstream or downstream of the constraint. Thus, adoption of the path approach would require shippers paying for capacity in the upstream portion of the zone to pay the same rate as those shippers with capacity downstream of the constraint point, although the upstream shippers would, in many cases, be unable to reach points downstream of the constraint.

Because zones do not correspond with constraint points, adoption of the path approach also could result in difficulties in allocating primary point capacity. Shippers currently have an incentive to subscribe to the primary delivery points at which they most need gas, because nominations to primary points are accorded the highest scheduling priority. Under the path approach, however, all shippers within a zone will have an incentive to subscribe to a primary point as far downstream in the zone as they can even though the pipeline does not have sufficient capacity to satisfy all shippers' downstream requests for capacity. All shippers would have the incentive to move their primary points to the end of a zone because each shipper pays the same rate to subscribe to the downstream delivery point as its former upstream delivery point and, under the path

approach, would obtain essentially the same priority to deliver to its former upstream delivery point as it would if it chose that upstream delivery point as its primary point. Meanwhile, by subscribing to the downstream primary delivery point, the shipper would obtain more valuable rights in the capacity release market because its path would go through the constraint point. As a consequence, adoption of the path approach could result in all shippers in a zone seeking to subscribe to downstream primary points even though the pipeline does not have sufficient capacity to provide all shippers with downstream capacity.

Making adjustments to secondary point priority, therefore, is not the most effective solution to the constraint problem. A more direct solution would be for the pipeline to revise its zone boundary so that the shipper upstream of the constraint point pays a lower rate than the shipper downstream of the constraint point.

Another approach to solving constraint issues is to design a capacity trading system for the future that improves upon the current system by permitting shippers to reallocate capacity rights after the pipeline has scheduled capacity and imposed whatever cuts may be applicable. For instance, if, due to constraints, the pipeline allocates capacity at secondary points on a pro rata basis, and the upstream shipper values the right to deliver to the secondary point more than the downstream shipper, an efficient capacity trading system would permit the upstream shipper to buy extra rights from the downstream shipper. Dynegy contends that, on some pipelines, shippers often are able to reach secondary delivery points even when the pipeline limits shipments to those points

by paying to arrange a backhaul from their downstream primary delivery point to the upstream secondary delivery point. The Commission obviously cannot resolve the appropriateness of the pipeline's backhaul charge under the current system in this generic rulemaking. However, the payment of an added charge, either to the pipeline or to another shipper, might be appropriate to reflect the additional value the shipper places on the capacity if an efficient trading system were in place so there was effective competition to the pipeline's provision of a backhaul service.

Because some pipelines' reticulated systems do not provide shippers with capacity paths and because the path concept is not inherently a more efficient allocation system than the current system used on most pipelines, the Commission will not adopt a generic requirement that all pipelines adopt the path priority system. Issues relating to priority schemes on individual pipelines can be addressed in pipeline filings where all factors, such as zone boundaries, rate structures, and the effect of such changes on shippers and competition can be examined.

3. Confirmation Practices

The Commission is not adopting a generic regulation regarding pipeline confirmation practices. In the NOPR, the Commission asked if the current practices of pipelines in confirming gas flows across interconnect points between pipelines adversely affects capacity allocation. Confirmation refers to the practice by which a pipeline communicates with upstream and downstream parties (other pipelines, producers, LDCs, point operators) to determine whether a shipper submitting a nomination on its system

will receive the nominated gas from the upstream producer or pipeline and whether the downstream pipeline or LDC is able to take delivery of that quantity of gas. If a nomination is not confirmed on either the upstream or downstream ends of the system, the shipper may not receive the amount of gas it has nominated.

The Commission requested comment on whether confirmation practices between interstate pipelines was affecting the allocation of primary and secondary capacity between pipelines. In particular, the Commission asked whether, when a constraint exists at an interconnect point, the general rule should be that the shipper with the higher priority on the downstream or take-away pipeline should receive priority.

The comments on this issue varied greatly. AGA advocates giving priority to the shipper on the downstream pipeline. Amoco argues priority should be given to the shipper on the upstream pipeline. Indicated Shippers argues that priority should be determined by the priority rules of the pipeline operating the interconnect point. NGSA contends the priority rule of the pipeline with the constraint should govern, but if the constraint is at the meter, then the priority rule of the party responsible for measurement at the meter should control. INGAA maintains that no changes in confirmation practices are necessary, since its companies report that very little gas flow has been affected by confirmation practices and no complaints have been made to the Commission about this issue. INGAA contends that, rather than favoring shippers with firm transportation either on the upstream or downstream pipeline, shippers should be responsible for contracting for primary or secondary firm capacity on both pipelines to assure their gas flows.

Given the lack of agreement among the industry and the paucity of complaints at this time, the Commission is not adopting a generic rule to govern confirmation at pipeline interconnects. However, the Commission agrees with INGAA's position that when pipelines do not have sufficient capacity at an interconnect to handle all nominations to that point, a shipper that has obtained firm capacity on both sides of an interconnect generally should have shipping priority over a shipper that is using interruptible transportation on one of the pipelines. If shippers believe that pipelines are not allocating capacity properly at interconnects, such problems can be handled individually through the complaint process.

C. Imbalance Services, Operational Flow Orders and Penalties

One of the fundamental purposes of this rule is to improve efficiency in the short-term market. The operational flow orders (OFOs) and penalties imposed by a pipeline to protect the integrity of the pipeline system are an area where improvements in efficiency can be achieved.

OFOs generally restrict service or require shippers to take particular actions. For instance, an OFO can reduce or eliminate tolerances for imbalances or contract overruns; institute severe penalties; or restrict intra-day nominations, the use of secondary receipt and delivery points, or firm storage withdrawals. Penalties are designed to deter shippers from creating imbalances, or from overrunning contract entitlements, and include penalties for physical imbalances (differences between commodity input and output),

scheduling imbalances (differences between actual and scheduled quantities), and non-compliance with OFO and other tariff provisions.

While OFOs and penalties can be important tools to correct and deter shipper behavior that threatens the reliability of the pipeline system, the current system of OFOs and penalties is not the most efficient system of maintaining pipeline reliability. The manner in which pipelines impose OFOs and penalties often limits efficiency in the short-term market by restricting shippers' abilities to effectively use their transportation capacity. Shippers make purchasing decisions based on gas commodity prices in the market. OFOs can limit the ability of shippers to respond to prices in the market, undermining the fluidity of the commodity market. For example, an OFO that eliminates a secondary receipt point for a shipper may eliminate the shipper's access to alternate suppliers with the lowest priced gas, or force the shipper to points where it has no purchase or sales agreements. By eliminating or changing a transaction that otherwise would have taken place, an OFO can interfere with the liquidity of the commodity market.

Commission-authorized penalties provide an opportunity for shippers to engage in a form of penalty arbitrage, both across pipeline systems, and within a single pipeline system. Arbitrage across pipeline systems occurs where shippers intentionally overrun contract entitlements on those pipelines and LDCs that have the lowest penalties for contract overruns, and then flow gas to shippers on other systems with higher penalties, in an attempt to capture the economic gain of the difference in the level of penalties. In that

situation, penalties skew the choices shippers might otherwise have made. The consequence is that, subsequently, pipelines in the area escalate their penalties to achieve the highest overrun/imbalance penalties.¹⁷⁸

Penalty arbitrage on a single pipeline system involves pipelines' existing tariff provisions for remedying monthly imbalances of a shipper--often described as "cash-outs." Under these provisions, shippers are allowed to cash-out net monthly imbalances using an average monthly price. That procedure invites shippers to game the system within the month. For example, a shipper may take more than it delivers when gas prices are higher than cash-out prices, and deliver more than it takes when gas prices are lower than cash-out prices. To the extent that pipelines rely on additional storage capacity to accommodate these imbalances, the arbitrage activity imposes costs on all shippers on the system through higher transportation rates that include more storage costs. In addition, at peak, arbitrage behavior may imperil systemwide reliability and trigger OFOs and emergency penalties that replace market forces with administrative rules.

In order to protect the reliability of their systems, many pipelines have responded to arbitrage on their systems by imposing stricter imbalance tolerances and higher penalties. High penalty levels often operate to limit and distort market forces. For example, the prospect of incurring high overrun and/or imbalance penalties, may cause

¹⁷⁸Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202 at 61,876 (1997) (penalties ranging from \$25 per Dth for variances of 5-10 percent to \$200 for variances over 50 percent).

shippers to fail to maximize their use of pipeline transportation, or to contract for more transportation capacity than they need.

The existence of arbitrage on and across pipeline systems indicates that in today's market, shippers are using penalties to achieve flexibility with respect to obtaining gas supplies and transportation capacity. In effect, shippers are treating the ability to overrun contract entitlements or create an imbalance as a "service." Instead of buying gas or transportation, shippers are overrunning their contract entitlements, or taking more or less gas than they deliver, and paying cashouts and penalties, where that option is less expensive than purchasing gas or transportation directly. For example, by incurring an imbalance, a shipper is essentially borrowing gas from the pipeline, and the amount of the imbalance cash-outs and penalties are, in effect, the price for such borrowing. Indeed, during peak periods, the level of penalties can set the market price for gas since the maximum penalty level for overrunning a contract can set the maximum price that a shipper would pay for obtaining additional capacity.¹⁷⁹ In many cases, however, the amount of the penalty is unlikely to match the cost to the pipeline of providing this flexibility, so that other shippers must pay for some of the costs.

Since the penalty system is being used by shippers to indirectly gain needed flexibility, and engage in behavior that may be harmful to the system as a way to obtain

¹⁷⁹See Industry Surveys the Damage as Winter's Strength Runs Out, Natural Gas Intelligence, April 22, 1996, at 1, 4 (penalty levels were a real factor in determining the price of gas during peak demand period in the Midwest).

such flexibility, the Commission finds that a general shift in Commission policy is warranted so that penalties are imposed only when needed to protect system integrity. Shippers need to be given tools that will enable them to reduce penalties without jeopardizing pipeline integrity, and shipper and pipeline incentives need to be properly structured to avoid the need to impose penalties. For example, simply because one shipper runs a positive imbalance, system integrity may not be jeopardized if other shippers run negative imbalances that offset the positive imbalance. The Commission has previously required pipelines in such situations to permit shippers to trade offsetting imbalances, which reduces the need for imbalance penalties while maintaining pipeline integrity.¹⁸⁰

Another method of using market transactions to reduce the need for penalties is for pipelines or third-parties to enable shippers to avoid penalties by providing shippers with flexibility, directly, through the provision of separate imbalance management services, and to require the shippers who use that flexibility to pay for it. Thus, the Commission is refocusing its policy away from a "command and control" type of policy that fosters the use of OFOs and penalties to a "service-oriented" policy that gives shippers other options to obtain flexibility.

¹⁸⁰Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587-G, 63 FR 20072 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062 (Apr. 16, 1998).

Under the new policy, pipelines will be required to provide imbalance management services, like parking and loaning service, and greater information about the imbalance status of shippers and the system, to make it easier for shippers to remain in balance in the first instance. Pipelines also will be required to permit third-parties to offer imbalance management services that will allow shippers to avoid imbalances. The use of these techniques will obviate the need for pipelines to rely on penalties to prevent or solve operational problems caused by shippers. This will allow penalties to be more narrowly crafted to focus on conduct that is truly detrimental to the system.

Equally as important as providing shippers with greater ability to avoid imbalances and penalties, is providing shippers with increased incentives to avoid imbalances and conduct harmful to the system. To this end, the Commission is encouraging pipelines to develop financial incentives for shippers to stay in balance, or to incorporate other types of incentives in the design of their imbalance management services. Replacing the negative incentive that penalties provide to deter behavior with more positive incentives to induce desirable shipper behavior will reduce imbalances and penalties, and may help alleviate gaming on pipeline systems.

Moreover, to effectively shift pipelines to the use of the non-penalty mechanisms described above to solve and prevent operational problems, it will be necessary to eliminate the pipelines' financial incentive to impose penalties and OFOs. Thus, the Commission is requiring pipelines to credit the revenues from penalties and OFOs to shippers.

More specifically, the Commission is revising its regulations governing standards for pipeline business operations and communications¹⁸¹ to add three new provisions, concerning imbalance management, operational flow orders, and penalties, that establish several general policies designed to help shippers avoid penalties and OFOs, and help pipelines minimize their need for and use of penalties and OFOs. As described in more detail below, these provisions require pipelines to offer imbalance management services, to establish incentives and procedures to minimize the use of OFOs, to establish only those penalty structures and levels that are necessary and appropriate to protect the system, to credit penalty and OFO revenues to shippers, and to provide more imbalance information on a timely basis. To implement these new regulations, each pipeline will be required to make a pro forma compliance filing no later than May 1, 2000. In its filing, each pipeline must either propose pro forma changes to its tariff to implement the requirements discussed above, or explain how its existing tariff and operating practices are already consistent with, or in compliance with, the new requirements.

The policies set forth in the provisions below are the same general policies that the Commission proposed in the NOPR. There was considerable support among the commenters for the goals underlying the Commission's proposed policies.¹⁸²

¹⁸¹These regulations appear in existing section 284.10, which the Commission is redesignating section 284.12

¹⁸²Comments of AEC, AF&PA, AGA, Columbia LDCs, Duke Energy, Dynegy, Exxon, Florida Cities, IPAA, Indicated Shippers, MichCon, Midland, NEMA,
(continued...)

1. Policies Adopted by this Rule

- a. Imbalance Management

The Commission is adopting a new subsection addressing imbalance management in its regulation governing the standards for pipeline business operations and communications. New section 284.12(c)(2)(iii), adopted herein, provides as follows:

(iii) Imbalance management. A pipeline must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. A pipeline also must provide its shippers the opportunity to obtain similar imbalance management services from other providers and shall provide those shippers using other providers access to transportation and other pipeline services without undue discrimination or preference.

This provision establishes the policy that pipelines must provide to shippers, to the extent operationally feasible, imbalance management services, such as park and loan service, swing on storage service, or imbalance netting and trading. As part of this policy, the Commission specifically encourages the use of auctions for shippers to trade imbalances so that they can avoid the imposition of unnecessary penalties. In addition, under this policy, pipelines will not be permitted to give undue preference to their own storage or balancing services over such services that are provided by a third party. The Commission is requiring pipelines to include these imbalance management services as part of their tariffs.

¹⁸²(...continued)

Philadelphia Gas Works, Process Gas Consumers, WGL, and Wisconsin Distributors.

The Commission expects pipelines to provide as many different imbalance management services as is operationally feasible, and to work to develop new, innovative services that help shippers manage or prevent imbalances. In order to give pipelines an incentive to develop these new imbalance management services, the Commission is not changing its current policy that pipelines may retain the revenues from a new service initiated between rate cases. In addition, the Commission particularly encourages pipelines to design imbalance management services that will give shippers a built-in incentive to utilize the service, or to otherwise stay in balance. Pipelines are also urged to create positive financial inducements for shippers to remain in balance or avoid behavior that is harmful to the system, rather than the negative incentives provided by penalties.

The Commission in Order No. 587-G has already taken a first step toward increasing shippers' abilities to manage imbalances by requiring that every pipeline:

- (a) allow firm shippers to revise nominations during the day (thereby reducing the probability of imbalances caused by inaccurate nominations);
- (b) enter into operational balancing agreements at all pipeline-to-pipeline interconnections;
- (c) permit shippers to offset imbalances across contracts and trade imbalances amongst themselves when such imbalances have similar operational impact on the pipeline's system; and
- (d) provide notice of OFOs and other critical notices by posting the notice on their Internet web sites.¹⁸³

The other actions the Commission is taking in this rule will also help shippers

¹⁸³Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. (continued...)

avoid imbalances and penalties, and reduce the need for OFOs. For example, shippers will have an alternative means of acquiring capacity during peak periods, other than overrunning their contract entitlements and incurring unauthorized overrun penalties, now that the Commission is removing the price cap from released capacity.

However, many pipelines currently do not offer effective imbalance management services, such as swing on storage or parking and loaning services. Other pipelines already offer some imbalance management services, but could improve upon them, or supplement them with additional imbalance management services, to the extent operationally feasible. The ready availability of imbalance management services will make it easier for shippers to stay in balance and avoid causing operational problems. Thus, a further expansion of the number of services available on each pipeline that facilitate a shipper's ability to manage imbalances will significantly increase shippers' ability to avoid imbalances, and correspondingly reduce the need for pipelines to impose penalties.

Moving towards a system where customers pay directly for imbalance management services will impose the costs of those services on those shippers needing the service, minimizing the impact on other customers that require less flexibility. Thus,

¹⁸³(...continued)

587-G, 63 FR 20072 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062 (Apr. 16, 1998). GISB's Executive Committee approved business practice standards for trading and netting of imbalances at its July 15-16, 1999 meeting, however the electronic standards have yet to be finalized. [Http://www.gisb.org/ec.htm](http://www.gisb.org/ec.htm) (Nov. 15, 1999).

it should shift costs that are now collected from all shippers through general transportation charges to those shippers that most require the needed flexibility.

However, pipelines will not be permitted to implement the new imbalance services until they also implement imbalance netting and trading on their systems. Pipelines should not expect shippers to purchase new services until the shippers can determine whether imbalance trading will be adequate for their needs. Thus, the implementation of the new imbalance management services must coincide with the implementation of imbalance netting and trading. Since GISB has already approved business practice standards for imbalance netting and trading, pipelines should be able to implement imbalance netting and trading at the same time that they implement the new imbalance management services.

This policy is the same policy proposed in the NOPR. Various commenters offered their support for this principle, urging the need for pipelines to offer imbalance management solutions prior to imposing penalties.¹⁸⁴ The little opposition to this principle comes from INGAA, and several pipelines who maintain that no changes at all are needed to the Commission's penalty policy.¹⁸⁵ INGAA maintains that a policy requiring pipelines to provide imbalance management services is unnecessary given that pipelines must provide such services to stay competitive with those pipelines that already

¹⁸⁴Comments of AF&PA, AlliedSignal, Amoco, Dynegy, FPL, Indicated Shippers, IPAA, and Shell.

¹⁸⁵Comments of INGAA, Williston Basin, and Koch.

provide such services.¹⁸⁶ Williston Basin states that services such as park and loan service do not need to be mandated by the Commission. It asserts that the need for, and implementation of, imbalance management services should be between the pipeline and its shippers. Williston Basin argues that having the Commission require a "cookie-cutter" imbalance management service for all pipelines will not provide the best imbalance service for a specific pipeline.¹⁸⁷

The Commission finds that requiring pipelines to provide imbalance management services, to the extent operationally feasible, is a key step in creating a policy that focuses more on providing flexible service options, minimizing the need for OFOs and penalties. The availability of imbalance management services is critical for providing many shippers with the flexibility they need to avoid or correct imbalances, which in turn obviates the need for pipelines to impose OFOs and penalties. The Commission must require pipelines to provide imbalance management services, despite the competitive incentive INGAA states pipelines already have to provide these services, since an incentive to provide such services alone will not guarantee that each pipeline will in fact provide the services. However, to the extent pipelines are already motivated to provide imbalance management services to remain competitive, compliance with the requirement

¹⁸⁶Comments of INGAA at 107.

¹⁸⁷Comments of Williston Basin at 35.

in this rule that pipelines offer such services should not be particularly difficult or burdensome.

With respect to Williston Basin's argument that the choice whether to provide imbalance management services and how to do so are business decisions that the Commission should allow each individual pipeline to make, the Commission stresses that by requiring pipelines to offer imbalance management services, the Commission is not dictating which services, or how many services, a pipeline must provide. Much of the decisionmaking, including whether the provision of such services is operationally practicable, is still left to the pipeline and its shippers. Also, the Commission is not dictating the exact details of these services for each pipeline, so that contrary to Williston Basin's understanding, the Commission is not imposing a one-size-fits-all imbalance management service on pipelines.

b. Operational Flow Orders

The Commission is adopting another new subsection in section 284.12(c)(2) of its regulations to govern OFOs. New section 284.12(c)(2)(iv), adopted herein, provides as follows:

(iv) Operational flow orders. A pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system. A pipeline must set forth in its tariff clear standards for when such measures will begin and end and must provide timely information that will enable shippers to minimize the adverse impacts of these measures.

This provision establishes the policy that each pipeline must adopt incentives and procedures that minimize the use and potential adverse impact of OFOs. The imposition of OFOs may severely restrict the purchase and transportation alternatives available to a customer during peak periods, precisely when such alternatives are critically needed to enhance the opportunities of a shipper to purchase such services at the lowest competitive prices. Under current practice, pipelines have incentives to favor OFOs as the first option, not the last resort. The pipeline is likely to err on the side of using an OFO, because it bears the risk that if it does not, curtailment of load may result that could in turn precipitate strong public disapproval and law suits from firm customers. In contrast, shippers--not pipelines--bear the costs that result from imposition of OFOs. A pipeline could also prefer OFOs because it would limit or eliminate a shipper's ability to purchase transportation that would be in lieu of transportation services provided by that pipeline. In some cases, shippers have complained that OFOs have been issued too frequently, for too long, and were larger in scope than required to protect the integrity of system operations.¹⁸⁸

In light of these considerations, it is appropriate to require the revision of existing pipeline tariffs to ensure that the imposition and adverse impact of OFOs are reduced to

¹⁸⁸See, e.g., NorAm Gas Transmission Company, 79 FERC ¶ 61,126, at 61,546-47 (1997); Southern Natural Gas Company, 80 FERC ¶ 61,233, at 61,890 (1997) Northern Natural Gas Company, 77 FERC ¶ 61,282 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202 (1997); Northwest Pipeline Company, 71 FERC ¶ 61,315 (1995).

the maximum extent practicable.¹⁸⁹ Many commenters favored this proposal in the NOPR to make each pipeline's tariff conform to this standard.¹⁹⁰ Therefore, to implement this policy, the Commission is requiring each pipeline to revise its tariff in the following respects, to the extent necessary.

First, each pipeline's tariff must state clear, individual pipeline-specific standards, based on objective operational conditions, for when OFOs begin and end. This will enable shippers to better anticipate in advance, based on market conditions, when OFOs are likely to be in effect and to plan their business affairs accordingly.

Second, the tariff must require the pipeline to post, as soon as available, information about the status of operational variables that determine when an OFO will begin and end. For example, if an OFO will remain in effect until repairs are completed on a compressor, the pipeline must be required to update shippers on the status of the repairs.

Third, the tariff must state the steps and order of operational remedies that will be followed before an OFO is issued to assure that the OFO has the most limited application practicable and to limit the consequences of its imposition. For example, one requirement would be that a pipeline provide as much advance warning as possible of the conditions

¹⁸⁹The requirement in this rule that pipelines automatically credit OFO penalty revenues to shippers will also help limit any incentive for the pipeline to use an OFO to generate revenues.

¹⁹⁰Comments of AF&PA, AGA, Florida Cities, Indicated Shippers, IPAA, MichCon, Midland, NEMA, Proliance and Shell.

that may create an OFO and the specific OFO itself that would allow customers to respond to such conditions and/or prepare alternative arrangements in the event the OFO is implemented.

Fourth, the tariff must set forth standards for different levels or degrees of severity of OFOs to correspond to different degrees of system emergencies the pipeline may confront. For example, a large OFO penalty may be appropriate in severe cases, whereas a small OFO penalty may be appropriate in others.

Fifth, the tariff must establish reporting requirements that provide information after OFOs are issued on the factors that caused the OFO to be issued and then lifted. This requirement is in addition to the existing requirement that pipelines provide notice of OFOs and other critical notices by posting the notice on the pipelines' Internet web sites and by notifying the affected customers directly.¹⁹¹

A few commenters request that the Commission refrain from requiring pipelines to adopt tariff provisions designed to curb the use of OFOs. Enron Pipelines state that OFOs are a vitally important tool to effect operational changes by specific shippers causing problems, and are not designed to assess penalties.¹⁹² Enron Pipelines believe that the potential for operating conflicts among shippers will only increase in the future, making OFOs increasingly important. Enron Pipelines argue that by requiring a pipeline

¹⁹¹Redesignated section 284.12(c)(3)(vi).

¹⁹²Comments of Enron Pipelines at 48-50.

to take all reasonable actions to minimize the issuance of OFOs, the Commission is essentially saying that it prefers that the pipeline take systemwide measures, such as the purchase of line pack gas, or the operation at reduced capacity levels, rather than the narrowly targeted solution of an OFO. Enron Pipelines do not believe that is the Commission's intent.

The requirement that pipelines establish standards and procedures for the imposition of OFOs, and the Commission's guidance to pipelines in that effort, is not meant to prevent pipelines from issuing OFOs where necessary, as Enron apparently believes. However, while the Commission is not committing pipelines to take systemwide measures to resolve operational problems, in some instances, it could be more appropriate to take actions other than issuing a specific OFO.

Williams, also, maintains that no major policy changes are needed regarding OFOs.¹⁹³ It asserts that any OFO problems are confined to only a few systems, and are not industry-wide. Therefore, Williams suggests that rather than requiring pipelines to revise their existing OFO provisions, the Commission should monitor the frequency of OFOs on individual pipelines. Then, Williams states, if a pipeline frequently issues OFOs, a proceeding could be established to determine if changes are necessary to that pipeline's tariff. INGAA, as well, agrees with a pipeline-specific approach.¹⁹⁴

¹⁹³Comments of Williams at 21-23.

¹⁹⁴Comments of INGAA at 109-112.

The Commission disagrees with Williams that it is not necessary at this time to require all pipelines to develop OFO standards. The Commission is not requiring all pipelines to adopt the same, generic standards. The Commission is requiring OFO guidelines on an individual pipeline basis to allow each pipeline to devise a set of OFO procedures that are specific to its system, and that may take into account the pipeline's OFO track record. These guidelines will help limit the imposition of OFOs to only those that are necessary, as well as limit the incurrence and duration of necessary OFOs, so that shippers can rely more on market forces in making their decisions. However, the Commission may, in the future, decide also to monitor the frequency of OFOs on individual pipelines, and thereafter institute proceedings to determine if further tariff changes are warranted for particular pipelines, as Williams suggests. With respect to INGAA's concern, the guidelines set forth in this rule will not prevent pipelines from determining what OFO standards are appropriate for their systems, or from issuing OFOs where necessary.

c. Penalties

Finally, new section 284.12(c)(2)(v), governing penalties and adopted herein, provides as follows:

(v) Penalties. A pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service. Pipelines may not retain net penalty revenues, but must credit them to shippers in a manner to be prescribed in the pipeline's tariff. A pipeline must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.

This new provision establishes three general principles with respect to penalties. First, penalties are not required, but to the extent that a pipeline assesses penalties, they must be limited to only those transportation situations that are necessary and appropriate to protect against system reliability problems. The Commission has authorized extremely high overrun and imbalance penalties for several pipelines on the basis that doing so was required to protect system integrity.¹⁹⁵ However, the Commission finds that there is not necessarily a connection between the high level of authorized penalties and the level that is necessary to ensure system reliability. By requiring that all penalties be necessary to prevent the impairment of reliable service, the Commission is requiring pipelines to narrowly design penalties to deter only conduct that is actually harmful to the system.

Also, the Commission is aware that some pipelines have penalties that are at the same level during peak and non-peak periods and may be imposed regardless of whether the pipeline is faced with emergency conditions.¹⁹⁶ Non-critical day penalties, or penalties imposed during off-peak periods, may not be the most appropriate and effective to protect system operations. Establishing a principle that all penalties must be necessary

¹⁹⁵See, e.g., Northern Natural Gas Company, 77 FERC ¶ 61,282, at 62,236 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202, at 61,876-77 (1997), reh'g denied, 82 FERC ¶ 61,163 (1998).

¹⁹⁶See Tennessee Gas Pipeline Company, 81 FERC ¶ 61,266, at 62,312; reh'g denied, 83 FERC ¶ 61,063, at 61,335 (1998) (contrasting a penalty based on spot pricing which varies penalty levels in response to market conditions with other pipelines with fixed penalty levels).

for reliable system operations will help ensure that penalties are appropriately drawn and tailored to reflect the potential harm to the system. Therefore, in the compliance filing to implement this principle, the Commission directs all pipelines to either explain or justify their current penalty levels and structures under these standards, or revise them to be consistent with this principle.

In cases in which penalties are needed to protect against harm to the pipeline system, the requirement that pipelines provide imbalance management services and permit third-parties to offer such services provides shippers with the flexibility to avoid conduct harmful to the system and penalties associated with such conduct. Thus, pipelines should be able to recraft their current broad penalty provisions in ways that directly focus on harm to the system and do not encourage the use of penalties as a substitute for obtaining services. As an example, pipelines may be able to change the methods by which they cash-out imbalances to eliminate the incentives for shippers to borrow gas from the pipeline because the cash-out price is less than the market price for gas. Rather than borrowing gas from the pipeline and paying the cash-out price, shippers can more directly obtain the flexibility they need by directly purchasing a parking and lending service from the pipeline or a third-party.

Second, new section 284.12(c)(2)(v) establishes the policy that a pipeline may not retain the revenues from penalties, but must credit them to shippers. The Commission is requiring pipelines to automatically credit all revenues from all penalties, net of costs, including imbalance, overrun, cash-out, and OFO penalties, to shippers. Ideally, penalty

revenues should be credited only to non-offending shippers so that offending shippers are not able to recoup the penalties they have paid, and thus, shippers are given a positive incentive to avoid incurring penalties. It is possible for pipelines to construct penalty revenue crediting mechanisms that exclude shippers who were assessed the penalty from the revenue credits.¹⁹⁷ However, the Commission recognizes that for some pipelines it may be difficult to develop or implement such a penalty revenue crediting mechanism. Thus, the Commission will not prescribe on a generic basis the details of the revenue crediting mechanism, including which shippers will receive the penalty revenue credits. Instead, the Commission will permit each pipeline to formulate an appropriate method for implementing penalty revenue crediting on its system. Pipelines should include the detail of their revenue crediting mechanism in the pro forma tariff filings, discussed infra, that the Commission is requiring pipelines to make to comply with this new rule.

The Commission's policy has been to allow pipelines to retain penalty revenues until the next rate case, and then to permit penalty revenues to be taken into account in the rate case when developing a pipeline's revenue requirement. The theory underlying the Commission's policy was that a properly designed penalty deters violations, and thus, there should be little or no penalty revenues to credit. This rationale was upheld by the

¹⁹⁷For example, under Northwest Pipeline Corporation's penalty revenue crediting mechanism, Northwest credits penalty revenues monthly only to shippers who were not assessed a penalty. See Section 14(g) of the General Terms and Conditions of Northwest's tariff. Fourth Revised Sheet No. 232-D and Second Revised Sheet No. 232-E, Third Revised Volume No. 1 of Northwest's FERC Gas Tariff.

U.S. Court of Appeals for the D.C. Circuit in Pennsylvania Office of Consumer Advocate v. FERC.¹⁹⁸ There, the court rejected a claim that the pipeline should be required to credit back all penalty revenues to non-offending shippers, where in the prior year, no penalties had been assessed under the penalty rate at issue. The court agreed with the Commission that based on such circumstances, "the mere possibility of revenue gains" did not "justif[y] a prospective requirement that the revenues be credited to customers."¹⁹⁹

However, the prospect of retaining revenues from penalties offers an incentive for pipelines to propose or implement inappropriate penalties and OFOs that can hinder efficiency and competition. Also, to the extent the penalty revenues are not reflected in rates, since pipelines are no longer required to file rate cases on a periodic basis, the penalty provisions have had the ability to result in profit centers for the pipelines.²⁰⁰

Given the Commission's new emphasis in this rule on providing services to facilitate shippers' ability to avoid imbalances and penalties and providing inducements to shippers to remain in balance, rather than on penalties, the Commission does not expect

¹⁹⁸Pennsylvania Office of Consumer Advocate v. FERC, 131 F.3d 182 (D.C. Cir. 1997), modified on other grounds, 134 F.3d 422 (D.C. Cir. 1998) (Pennsylvania).

¹⁹⁹Id., 131 F.2d at 187.

²⁰⁰FERC Form No. 2 data indicate that gross penalty revenues from the 15 pipelines that attributed revenue to penalties amounted to approximately \$24.3 million in 1996, \$9.6 million in 1997, and \$5 million in 1998. This reduction in gross penalty revenues may simply be a reflection of the relatively mild winters that have occurred in the past few years.

that significant revenues will be generated from penalties. However, to the extent that penalty revenues are generated, the required crediting of penalty revenues will eliminate any economic incentive for pipelines to rely on penalties rather than inducements. The Commission is requiring penalty revenue crediting not so much for the purpose of preventing penalties from becoming a profit center, but more for the purpose of eliminating any financial incentive on the part of pipelines to impose penalties that would naturally hinder the pipelines' movement toward reliance on the provision of imbalance services, greater imbalance information, and shipper incentives.

In addition, requiring pipelines to credit penalty revenues to shippers also responds to concerns that the court had subsequent to its Pennsylvania decision, in Amoco v. FERC,²⁰¹ about allowing pipelines to retain penalty revenues. In Amoco v. FERC, the court found that the Commission had not adequately supported its finding that the proposed increase in the penalty level would not provide the pipeline with significant penalty revenues, especially where the pipeline had collected \$1.8 million in overrun penalty revenues in the year prior to the pipeline's filing. The court remanded the case to the Commission for an explanation of how its decision to permit the pipeline to retain the penalty revenues and not require penalty revenue crediting is consistent with the NGA. Requiring the crediting of penalty revenues to shippers in this case will eliminate the

²⁰¹158 F.3d 593 (D.C. Cir. 1998).

potential for pipelines to receive penalty revenue windfalls, and consequently, the court's concern.

In the NOPR, the Commission suggested the crediting of penalty revenues as one of a number of options that could help pipelines to impose only necessary and appropriate penalties. The idea of crediting penalty revenues garnered much support in the comments.²⁰² However, a few parties are opposed to revenue crediting because they contend that no changes at all are necessary to the Commission's policies on penalties and OFOs.²⁰³ They assert that the current penalty tariff provisions have been carefully crafted by pipelines and their customers, meet each pipeline's operational needs, and deter inappropriate conduct.

The Commission disagrees. Allowing pipelines to retain penalty revenues gives pipelines the wrong incentives for the design and imposition of penalties, and provides no incentive for the pipeline to develop other, non-penalty mechanisms that would give shippers incentives to control their imbalances. As stated above, the crediting of penalty revenues eliminates the pipelines' financial incentive to use and impose penalties.

Third, section 284.12(c)(2)(v) establishes the requirement that pipelines provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of its system as a whole. Under this

²⁰²Comments of AGA, Dynegy, FPL, Indicated Shippers, Louisville, Minnesota, NASUCA, Nicor, Penn. PUC, Process Gas Consumers, and PSC of Wisconsin.

²⁰³Comments of INGAA, Koch, Williams, and Williston Basin.

policy, pipelines will be required to distribute to shippers the information that they currently have available on deliveries and imbalances at each shipper's delivery point, as well as on system imbalances. However, the Commission is not requiring pipelines to install upgraded, real time meters at receipt and delivery points.²⁰⁴ In other words, the requirement that pipelines provide as much imbalance information as possible is not meant to require that pipelines make an investment in additional metering equipment. The Commission will leave the decision of when and where to install upgraded metering to the pipeline and individual shippers, based on their own economic and operational judgment. The Commission will continue the current policy of permitting pipelines and their shippers to address these cost issues as they arise, *i.e.*, in general rate cases or, as provided in the pipelines' tariffs. At this time, no change in this aspect of the Commission's policy is necessary.

The pipelines must disseminate the available imbalance information on a timely basis, so that shippers will have a reasonable opportunity to avoid penalties. The Commission will require pipelines to establish a system that notifies each shipper individually of the imbalance/delivery information that the pipeline possesses, or to give shippers access to such information via the Internet. The pipelines, however, may post relevant system imbalance information more generally. The obligation that such information be provided on a timely basis will vary from pipeline to pipeline, depending

²⁰⁴This is consistent with the NOPR proposal.

on the pipeline's penalties. For example, a pipeline that imposes imbalance penalties only on a monthly basis would have a different obligation to provide imbalance information to its shippers than a pipeline that imposes daily imbalance penalties.

Providing imbalance information on a timely basis will enhance the opportunities of a shipper to avoid penalties and help prevent penalty situations. Information on the precise level of a shipper's deliveries and imbalances will help the shipper avoid overruns and imbalances, and maximize the use of its transportation rights on the pipeline system. Providing such information might also allow pipelines to reduce the level of penalty-free tolerances and to thus reduce system costs (e.g., storage capacity to provide such tolerances). Finally, such information, together with information on system imbalances, will facilitate the trading of imbalances and capacity, or other self-help measures, that in turn could alleviate or prevent conditions that imperil system integrity.

Under the regulations adopted in this rule, pipelines will only be able to impose penalties to the extent necessary. This requirement may result in either no penalties for non-critical days or higher tolerances and lower penalties for non-critical as opposed to critical days. To the extent that pipelines generally justify the imposition of penalties for non-critical days, the pipeline should not impose such penalties on shippers where the existing metering equipment does not provide the shipper with sufficiently accurate information about its imbalance status so that the shipper can take actions to avoid the penalty. During non-critical periods, to the extent a pipeline can justify having a penalty at all, the pipeline will only be allowed to impose penalties in time frames comparable to

the information it collects and disseminates to shippers, and for which reasonable notice and opportunity to cure overruns and imbalances is given. For example, if shippers are given information about their overrun and imbalance status on a daily basis, daily tolerances and penalties may be adopted. However, if shippers are given this information only on a monthly basis, only monthly penalties may be imposed. This approach will provide the pipeline with the appropriate incentive to install upgraded metering equipment if controlling imbalances at the point in question is important to the operation of its system.

During critical operating periods, however, the Commission will still permit pipelines to impose penalties on shippers when real-time metering, and/or timely reporting of shippers' imbalance status is not available. The need to maintain system integrity during critical days is of sufficient importance that the Commission does not want to limit the pipelines' ability to deter conduct that may be harmful to other shippers even if it cannot provide current information.

The Commission proposed this restriction as one of two options for addressing situations where, at particular receipt or delivery points, the pipeline might not have the type of metering and related equipment that would provide the shipper with timely information on its deliveries and imbalances. A number of commenters supported this option.²⁰⁵ The other option presented in the NOPR was to require the pipeline to install

²⁰⁵Comments of Florida DMS, Louisville, NGSA, Process Gas Consumers, and
(continued...)

equipment sufficient to provide shippers at those points with timely information on imbalances and deliveries. Many commenters opposed that option because it raises difficult issues, such as who should pay the costs of purchasing and installing the equipment. Requiring the pipeline to install adequate metering equipment at those points is inconsistent with the Commission's determination not to require upgraded metering equipment at all points. The Commission is not adopting this option.

While a significant percentage of the commenters support requiring pipelines to provide, on a timely basis, as much information as possible on imbalances and overrun status of each shipper, and system imbalance status,²⁰⁶ several commenters object to the Commission's requiring pipelines to provide "as much information as possible." National Fuel argues that this standard is nebulous, and is likely to result in the posting of much useless information. National Fuel requests that the Commission modify the proposed policy to require that pipelines "provide, on a timely basis, a quantification of the imbalance and overrun status of each shipper and the imbalance of the pipeline's system."²⁰⁷ Williston Basin maintains that the Commission should not require pipelines to provide as much volume information as possible, but should require pipelines to provide appropriate volume information on a net benefit basis and the relevance of the

²⁰⁵(...continued)
TransCanada.

²⁰⁶Comments of AlliedSignal, Florida Cities, NEMA, NGSA, Paiute, Process Gas Consumers, PUC of Ohio, Dynegy, and PSC of Wisconsin.

²⁰⁷Comments of National Fuel at 5.

volume information to the specific pipeline and its shippers.²⁰⁸ Consolidated Natural states that the language of the new provisions suggests that a pipeline must have real time measurement equipment in place.²⁰⁹ It asserts that pipelines' existing business, measurement and computer systems cannot manage the calculation of more detailed or more timely information.

The Commission is requiring the provision of only as much information as the pipelines already have available on shippers' imbalance and overrun status, and on system imbalance status. The Commission reiterates that it is not requiring that pipelines upgrade their existing business, measurement, and computer systems to provide this information. Also, the Commission does not wish to limit this information to a quantification of the shippers' imbalance and overrun status, and system imbalance status. There may be other information about imbalances, particularly with respect to system imbalances, that pipelines have available that could aid shippers in planning their actions and avoiding imbalances and penalties.

Atlanta, also, has a concern with the Commission's requirement that pipelines provide timely imbalance information.²¹⁰ Atlanta asserts that increasing the amount of information available to shippers will not be sufficient to prevent shippers from incurring imbalances unless shippers have the appropriate incentives to avoid imbalances. Atlanta

²⁰⁸Comments of Williston Basin at 35.

²⁰⁹Comments of Consolidated Natural at 25-26.

²¹⁰Comments of Atlanta at 17-18.

believes that shippers currently have the ability to control their imbalance activity, but choose not to because they find it economically beneficial to game the system. Atlanta supports requiring pipelines to provide as much information as possible, but only in conjunction with the provision of incentives for shippers to remain in balance. Further, Atlanta maintains that forbidding pipelines to impose imbalance penalties during non-critical periods where the pipeline has failed to notify the shipper of the imbalance situation will exacerbate the imbalance problem by removing disincentives for shippers to incur imbalances.

The Commission agrees with Atlanta that the existence of proper incentives for shippers to avoid imbalances is of paramount importance. The policy being adopted here, focused on avoiding penalties and reducing the need for penalties, is intended precisely to promote such incentives. The measures the Commission is taking here are designed to move the pipeline away from the use of negative incentives -- penalties and OFOs -- to the use of positive incentives to control shipper behavior. It is up to the pipeline to develop such positive incentives. However, the Commission's actions here are laying the groundwork for, and will facilitate, the pipelines' efforts in this direction. For example, by requiring pipelines to offer imbalance management services, the Commission is prompting pipelines to become creative in developing such services that may not only make it easier for pipelines to avoid imbalances, but may also provide built-in incentives for shippers to stay in balance. Also, the provision of timely information of shipper and system imbalance status, together with the pipeline's ability to establish appropriate

imbalance penalties, should in and of itself produce good incentives for shippers to stay in balance.

The Commission does not agree with Atlanta, however, that forbidding pipelines from imposing non-critical day penalties where the pipeline has failed to notify the shipper of the imbalance strips away shipper incentives to comply with tariff requirements. To the extent that pipelines continue to use a negative incentive, such as a penalty, to encourage shippers to remain in balance and deter behavior, it is a matter of basic fairness that the pipeline give notice of the imbalance situation and the opportunity to cure the imbalance prior to imposing a penalty that is not critical to operations.

2. Future Consideration of Penalty and OFO Issues

The Commission is adopting the general policies set forth above as an initial step toward increasing shipper flexibility to avoid penalties, and minimizing the need to impose penalties. However, in the NOPR, the Commission sought comment on a variety of options for implementing and expanding these general policies. For example, the Commission requested comment on whether more appropriate penalties might result from establishing uniform penalties and OFOs across pipelines on a national or regional basis, revising pipelines' cash-out procedures, or establishing a "no-harm, no-foul" policy that would permit beneficial imbalances to escape penalties. The comments to the NOPR produced no strong consensus on most of the specific options that the Commission presented for implementing and expanding the general policies.

As a result, while it is appropriate to take a modest step toward remedying the inefficiencies caused by penalties and OFOs through the adoption of the general policies, it is premature, without additional study and examination of the market, to undertake the more ambitious policies presented as options in the NOPR, or many of the detailed suggestions for a revised Commission policy on penalties that the commenters presented.²¹¹ The Commission recognizes that they may hold promise for the future. Thus, the Commission will continue to monitor the natural gas market and the role penalties play in that market, as the industry responds to the initial changes being adopted in this final rule to the Commission's penalty and other policies, and to the GISB standards for imbalance management recently put into place. In the event that the inefficiencies associated with penalties and OFOs persist, the Commission will revisit whether the more comprehensive and innovative policy changes are necessary.

To facilitate the Commission's consideration of additional, more significant changes in the Commission's penalty policy, if necessary after some experience under the rules adopted here, the Commission or its Staff may convene an industry-wide conference to examine the need for further generic reform of the industry's penalty standards. Such a conference would explore whether there are commodity arbitrage problems on individual systems and gaming across pipelines and LDCs due to different penalty levels, and whether it is feasible to set penalties and OFO standards on a regional or national basis.

²¹¹Comments of AF&PA, Amoco, Dynegy, Process Gas Consumers, and Exxon.

IV. REPORTING REQUIREMENTS FOR INTERSTATE PIPELINES

The free flow of information regarding the natural gas market is critical to the successful creation of a competitive and efficient marketplace. Access to relevant information is necessary for shippers to make informed decisions about capacity purchases, and for the Commission and shippers to monitor transactions to determine if market power is being exercised. Also, as competition is improved in the natural gas marketplace by the changes the Commission is making in this final rule, the ready availability of information will become increasingly important, both for efficient trading and for the monitoring for the exercise of market power.

The market needs several different types of information, both for decision-making and monitoring purposes: information on capacity transactions, such as rates, contract duration, and contract terms; information on the structure of the market; and information on capacity availability. Transactional information provides price transparency so shippers can make informed purchasing decisions, and also permits both shippers and the Commission to monitor actual transactions for evidence of the possible abuse of market power. Information on market structure enables shippers and the Commission to know who holds or controls capacity on each portion of the pipeline system, so the potential sources of capacity can be determined. Information on the amount of capacity available at receipt and delivery points and on mainline segments, as well as on the daily amount of capacity that pipelines schedule at these points, helps shippers structure gas transactions and casts light on whether shippers or the pipeline may be withholding capacity.

The Commission's current regulations already require the reporting and maintenance of much of the necessary information.²¹² However, the information required by the existing regulations gives market participants and the Commission an uneven picture of the market because the reporting requirements are different for competing types of capacity, both in terms of the content of the information and the formats used to report the information. For instance, pipelines are required to post detailed information on capacity release transactions, including the releasing and replacement shipper names, the rate paid, and points covered by the release, when the transactions occur.²¹³ In contrast, pipelines are only required to file limited information on their discount transactions well after the transaction has taken place.²¹⁴ In addition, some information needed to enable shippers to effectively make capacity decisions and monitor the market is not currently required by the existing regulations, such as certain point-specific data.

Therefore, the Commission is revising its reporting requirements in a few main respects to improve the availability and usefulness of the information currently reported. First, the Commission is changing and consolidating the reporting formats in which it

²¹²Information is currently provided through a variety of formats: the capacity release reporting standards (284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3), the Index of Customers (section 284.106 (c)), the discount report (section 284.7(c)(6)), and the maintenance requirement for discount information (section 250.16(d)).

²¹³18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3.

²¹⁴18 CFR 284.7(c)(6).

collects the information, including the time frames within which information is reported, to enable the Commission to equalize the reporting requirements for capacity release transactions and pipeline transactions, and to simplify the overall reporting system. The new reporting system reduces the amount of periodic reporting to the Commission currently required, and instead relies on Internet posting and maintenance of information. Second, the Commission is adding certain data to the information that is already collected on pipeline transactions, the structure of the market, and capacity availability in various reporting formats. Specifically, the most significant additional information being required here is receipt and delivery point data in the report on pipeline transactions and the Index of Customers, certain organizational and personnel information on affiliates, and information on design and scheduled capacity and service outages. Third, the Commission is reorganizing its regulations to consolidate all of the existing and new Part 284 reporting requirements into a single, new Section 284.13 governing open-access reporting requirements for interstate pipelines.

Under the new requirements, as detailed below, pipelines will be required to provide transactional information, information regarding capacity and service outages, an index of firm transportation customers, and information concerning marketing affiliates, most of which is already reported or maintained.²¹⁵

²¹⁵As a result of consolidating the reporting requirements into one place in the regulations, section 284.13 also includes the annual report on peak day capacity and storage capacity, and the semi-annual storage report, which are filed with the

(continued...)

- The transactional information on firm and interruptible transportation will be provided by posting the information on the pipelines' Internet web sites and through downloadable files. The transactional information on firm transportation, whether provided by the pipeline or through capacity release, is to be reported contemporaneously with the transaction. The information on interruptible transportation will be provided daily.
- The capacity information will provide information on available, scheduled, and design capacity and service outages through posting on the pipelines' web site and through downloadable files. The information on available and scheduled capacity will be posted daily. Information on design capacity will be posted one time (and thereafter maintained on the web site), and then updated as necessary. Service outages will be posted when required.
- The Index of Customers will be provided through a quarterly filing with the Commission, as well as by posting the information quarterly on the pipelines' Internet web sites.
- The affiliate information will be posted on the pipelines' Internet web sites, and will be updated within three days of changes in the information.

A. Transactional Information

To assure parity of the transactional information that is reported for capacity release transactions and for pipeline transactions, the Commission is requiring that pipelines provide the same information about their firm and interruptible transactions as is currently reported about capacity release transactions, in the same format. Therefore, the Commission is adding a new section 284.13(b) that will require pipelines to post on their Internet web site, and provide downloadable files of, transactional information about their

²¹⁵(...continued)

Commission. The Commission is not changing these regulations in this rule.

own capacity transactions and released capacity transactions.²¹⁶ Pipelines will be required to keep the firm and interruptible transactional information, described below, available on their web sites for 90 days. In accordance with the Commission's existing regulations, pipelines will also have to archive this information after the 90-day period expires, maintaining the information for a period of three years.²¹⁷

Specifically, for firm service, pipelines will be required to post the following information, contemporaneously with the execution of the contract: the names of the parties to the contract; an identification number for each shipper, such as a DUNS number; the contract number for the shipper receiving service and for the releasing shipper; the rate charged under each contract and the maximum rate, if applicable; the duration of the contract; the receipt and delivery points and zones or segments covered by the contract, as well as the common transaction point codes; the contract quantity, or volumetric quantity under a volumetric release; special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract;²¹⁸ and any affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper.

²¹⁶While new section 284.13(b) enumerates information the Commission needs for firm and capacity release transactions, it does not replace the existing GISB capacity release data sets.

²¹⁷Section 284.10(c)(3)(v), redesignated as section 284.12(c)(3)(v).

²¹⁸Under this requirement, a pipeline must report any special conditions attached to a discounted transportation contract, such as requirements for volume commitments to obtain the discount.

For interruptible transportation, the pipeline will be required to post the following information on a daily basis: the name of the shipper; a shipper identification number; the rate charged and maximum rate, if applicable; the receipt and delivery points and zones or segments over which the shipper is entitled to nominate gas, as well as the common transaction point codes; the quantity of gas the shipper is entitled to nominate; special details pertaining to a pipeline transportation contract; and any affiliate relationship between the shipper and the pipeline.

The Commission is also eliminating the separate discount report previously required by Section 284.7(c)(6). It will no longer be required, since the same information will be reported under the reports on firm and interruptible transactions in new Section 284.13(b). However, pipelines will be required to continue to file discount reports until September 1, 2000, when they are required to comply with the new reporting requirements.

Pipelines already provide, via the Internet, virtually all of the above transactional information for capacity release transactions, at the time of the transaction.²¹⁹ However, under the current regulations, pipelines are required to provide limited transactional information for their own capacity transactions, and the information that is required is neither as timely nor as easy to access as the capacity release information. Currently,

²¹⁹18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3. The only exceptions are that some pipelines are not required to report whether a capacity release transaction is between a releasing shipper and an affiliate, and contract numbers are not required to be reported.

pipelines must file discount reports, which require only some information on firm and interruptible transactions at less than the maximum rate – the name of the shipper, the maximum rate, the rate actually charged, and any corporate affiliation between the pipeline and the shipper.²²⁰ The discount report does not include any information on volumes, the receipt and delivery points for the transaction, or the duration of the contract. And, the discount report is filed, but not posted electronically, 15 days after the close of the billing period applicable to the transaction. Thus, the information provided in the discount report is limited in nature, is provided well after the transaction has taken place, and is filed with the Commission, rather than posted on the pipeline's EBB or on the Internet.

Some information regarding firm transactions is available in the Index of Customers, which requires that pipelines file the following information electronically with the Commission and on the pipelines' EBBs for each customer receiving firm transportation or storage service: the customer name, the amount of capacity held, the duration of the contract, and the applicable rate schedule.²²¹ However, the Index of Customers cannot truly be considered a transactional report, since it does not provide any price information or information on the capacity path held by the shipper. Therefore, it is of limited use in monitoring transactions for discrimination. In addition, the Index of

²²⁰18 CFR 284.7(c)(6).

²²¹18 CFR 284.106(c)(3).

Customers is only filed quarterly, and therefore reflects only those shippers that have contracts with the pipeline on the quarterly filing day. As a result, it is inadequate to capture shipper and contract information for short-term firm contracts that may begin and end within a quarterly filing period.

Thus, the discount report only provides some after-the-fact information regarding transactions at less than the maximum rate, the Index of Customers only provides some quarterly information regarding firm contracts, and neither reporting requirement provides any transactional information with respect to interruptible transactions at the maximum rate. Consequently, the content and reporting formats of the existing reporting requirements for pipeline transactions are inadequate to give shippers and the Commission a real-time snapshot of what price capacity sold for on a particular day. The pipeline data and reporting formats are not comparable to the existing reporting requirements for capacity release transactions. The reporting of the same information required to be provided in the capacity release reports, in the same format, is necessary with respect to pipeline transactions for shippers to have a complete and comprehensive view of the market.

The transactional reporting requirements the Commission is adopting here are generally the same reporting requirements proposed in the NOPR, with a few minor modifications. The Commission is adding to the firm and interruptible transactional reports proposed in the NOPR the maximum rate under each pipeline contract, to enable the magnitude of any discounts to be known, since the existing discount report is now

subsumed within the reports on firm and interruptible transactions. In addition, the Commission is adding to the transactional reporting requirements an individual shipper identification number, such as a DUNS number, to the extent one exists for a particular shipper, so that it will be easier to link together, or match-up, customer-specific data from different reports. The Commission is also adding the common point codes for the receipt and delivery points. The Commission has previously adopted the consensus recommendation of GISB that pipelines use common transaction point codes.²²²

Many commenters support the reporting requirements the Commission proposed in the NOPR and is adopting in this rule.²²³ Some commenters even advocate that the Commission should impose greater reporting requirements than those proposed in the NOPR.²²⁴ Other commenters, though, object to the Commission requiring pipelines to disclose specific information about pipeline transactions on confidentiality grounds.²²⁵

²²²See redesignated 18 CFR 284.12(b)(1)(v) Capacity Release Related Standards (Version 1.3), Firm Transportation and Storage-Award Notice, tab 8, at 2, tab 8 EDI, at 17-18. Under this provision, however, a pipeline can use a proprietary code if no common transaction point code exists, but will have two months within which to obtain a common code for that point.

²²³E.g., Comments of AEC, AF&PA, AGA, Amoco, CPUC, Duke Energy, Enron Capital, Florida Cities, Florida DMS, Industrials, Louisville, NEMA, Penn. PUC, Proliance, PSC of Kentucky, PUC of Ohio, Southern Co. Services, WGL, and Wisconsin Distributors.

²²⁴Comments of Amoco, Indicated Shippers, New England, Southern Company Services, TransCanada, WGL, and Wisconsin Distributors.

²²⁵Comments of Coastal, Dynegy, Duke, Process Gas Consumers, NICOR, PUC of Ohio, Sithe, Tejas, Williams, and Williston Basin.

They argue that such information, particularly customer names, receipt and delivery points, and contract numbers, is commercially sensitive information, which, if disclosed contemporaneously with the transaction, will cause shippers competitive harm.

For instance, Dynegy argues that disclosure of individual contract numbers and receipt and delivery points will make it easy for shippers to track the chain of title to determine where other shippers' supply came from and where it will end up. Dynegy states that knowledge of this information, together with the rates paid for the transportation, will allow shippers to undercut or steal other shippers' transactions.²²⁶ Dynegy does indicate, however, that it might not object to the release of such information to only the Commission, with appropriate confidentiality protection. Dynegy further maintains that it does not object to the disclosure of this information with respect to pipelines' transactions with their affiliates because there is an overriding need for pipelines to report such information for their marketing affiliates that outweighs concerns about commercial sensitivity.²²⁷

Similarly, Duke asserts that there is no need to identify specific shipper's nominated capacity at each point because such information would give shippers knowledge of their competitor's general marketing strategy and allow shippers to deduce

²²⁶Comments of Dynegy at 14-15.

²²⁷Comments of Dynegy at 8 and 14.

the identity of the markets themselves. Duke states that the identity of the shipper should be redacted from postings.²²⁸

Some commenters maintain that requiring pipelines to report the additional transactional information may have the unintended effect of increasing bundled sales activity.²²⁹ They state that because many shippers do not want to have the details of their transactions disclosed, they currently avoid capacity release transactions in favor of bundled sales transactions. Thus, the commenters argue that a policy of immediate disclosure of transactional information for pipeline transactions will cause even greater bundled sales transactions, and thereby frustrate the Commission's goal of increased market transparency.

In addition, the opposing commenters request that if the Commission decides to require public disclosure of the transactional information, at a minimum, it should not require the immediate disclosure of the information, but should revise the timing of the reporting requirement.²³⁰ They request that the reporting of the information, particularly the identity of the shipper, be delayed, so pipelines and shippers are not given an opportunity to use such information to gain a competitive advantage. They suggest

²²⁸Comments of Duke at 7.

²²⁹Comments of Coastal 93-94 and PUC of Ohio at 8. The comments of the PUC of Ohio on this point are limited to the disclosure of the transacting parties' identities.

²³⁰See Comments of Dynegy at 16, NICOR, at 21, and Industrials at 89.

delays ranging from 30 days after the transaction, to six months after service under the contract begins.

The Commission finds that the disclosure of detailed transactional information is necessary to provide shippers with the price transparency they need to make informed decisions, and the ability to monitor transactions for undue discrimination and preference. Shippers need to know the price paid for capacity over a particular path to enable them to decide, for instance, how much to offer for the specific capacity they seek. While the Commission acknowledges that the disclosure of shipper names is not necessary for this type of decisionmaking and price transparency, the disclosure of the identity of the shipper in each transaction, together with the price and capacity path information on each shipper's transaction, is necessary to enable shippers and the Commission to effectively monitor for potential undue discrimination or undue preference. The disclosure of all of the transactional information without the shipper's name will be inadequate for other shippers to determine whether they are similarly situated to the transacting shipper for purposes of revealing undue discrimination or preference. For example, the disclosure of the name of the shipper in the transaction may help other shippers to determine whether a transacting shipper may be entitled to a discount because it is fuel-switchable. In addition, the disclosure of the identity of shippers in the transactional reports enables shippers and the Commission to determine how much total firm capacity (both pipeline capacity and released capacity) a shipper holds on each individual pipeline, as well as on

connecting pipelines. Such information is important for examining market power and whether a shipper has sufficient market presence to unduly discriminate.

Moreover, the general regulatory scheme of section 4 of the Natural Gas Act is based on the public disclosure of all prices and contracts.²³¹ Thus, the posting of customer-specific information in the transactional reports being required here is consistent with this statutory framework. In addition, in requiring the shipper identity to be disclosed, the Commission is not changing or reversing its treatment of shipper names in the reporting requirements. The names of shippers are currently required to be posted for capacity release transactions and for discount transactions in the discount reports.

Finally, to be meaningful for decisionmaking purposes, the transactional information must be reported at the time of the actual transaction. A delayed reporting of the information 30 days or more after the transaction has occurred, as some commenters suggest, will not be timely enough to enable shippers to use the information on a day-to-day basis to make purchasing decisions. At that point, the information is historical, and is of no value for current decisionmaking. In other words, the knowledge of what capacity sold for what price 30 days earlier would not aid shippers in making a current capacity decision. Some commenters advocate a delayed posting of the shippers' names only. The Commission acknowledges that immediate disclosure of shippers' names is not necessary for the Commission and other shippers to monitor for undue discrimination and

²³¹15 U.S.C. 717(c).

preference. A delayed posting of the shipper names would suffice for the monitoring purpose for which the names are needed. However, a requirement that pipelines report different transactional information at different times is likely to be impracticable to implement, creating a burden that outweighs the need for confidentiality. Because it is necessary for all of the other transactional information to be posted at the time of the transaction, the Commission will require the identity of the shipper for each transaction also to be disclosed at the time of the transaction.

Commenters also have concerns regarding the burden that the Commission's revised transactional reporting requirements will place on pipelines.²³² For example, some commenters contend that requiring pipelines to post information on interruptible transactions on a daily basis is too burdensome.²³³ Williston Basin states that requiring these data on a daily basis is akin to uploading each pipeline's daily interruptible nominations (including all intraday cycles) on its Internet web site every day.²³⁴ It asserts that a pipeline's single timely nomination cycle can be thousands of records long, and that multiplying this by the intraday cycles day after day will prove to be an enormous amount of data. PSC of New York states that it may be impossible or impractical to post interruptible transactions before gas flows. PSC of New York

²³²Comments of AGA, Koch, MichCon, Tejas, and Williston Basin.

²³³Comments of Williston Basin and PSC of New York I.

²³⁴Comments of Williston Basin at 32.

suggests that the posting of interruptible transactions should be required as soon as possible after gas flows.²³⁵ In contrast, Amoco argues that the Commission should require the posting of all interruptible transactions contemporaneous with the execution of the contract.

The Commission does not expect that the burden of complying with the transactional reporting requirements will be great. Most of the information required for the pipeline's transactional report on firm and interruptible service is already required to be reported or maintained under existing requirements, such as the Index of Customers, the discount report, or the affiliate discount information maintenance requirement in Section 250.16(d) of the Commission's regulations, albeit separately, and in different formats.²³⁶ Thus, the burden will not be in collecting or gathering the data, but will largely be in creating the new formats for displaying the information on the pipelines' Internet web sites. Pipelines may, however, be able to adapt their already existing capacity release data sets to apply to pipeline transactions without much difficulty. Moreover, the Commission is reducing the periodic reporting currently required under the regulations by eliminating the monthly discount report.

²³⁵Comments of PSC of New York I at 14-15.

²³⁶The only true gap in the information currently reported is information on interruptible transactions at the maximum rate, since the discount reporting requirements, by definition, do not apply to maximum rate transactions.

While the Commission is requiring that some new data, not required in existing reports, be posted on firm and interruptible transactions, it is not an extensive amount of information compared to what is already provided. For the firm transactional report, the Commission is adding the receipt and delivery points and the zones or segments under the contract, the common transaction point codes, the contract number, a shipper identification number, and special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract. Similarly, for the interruptible transactional report, the Commission is adding the receipt and delivery points and zones or segments, the common transaction point codes, the contract quantity, a shipper identification number, and special details pertaining to a pipeline transportation contract. Further, these additional data are information that pipelines use in the course of their daily business activities, and thus, have in their possession, so that pipelines should not encounter great difficulty in assembling the information. Again, for pipelines to comply with the new reporting requirements, their task will be to develop a method for displaying the information on the web sites.

The Commission recognizes that the quantity of data to be posted on interruptible transactions could be voluminous for some pipelines. However, in order for shippers to have a true understanding of pricing in the marketplace, they must know what prices are being paid for interruptible transportation service and when such interruptible prices change. The existing discount report for interruptible transactions at less than the maximum rate is inadequate because it provides only a monthly average of the price paid.

Since the prices for interruptible service can change daily, it is necessary for the pipeline to post interruptible transactions on a daily basis. In addition, the Commission emphasizes that the Commission is requiring the posting of these data once daily, not contemporaneously with the execution of each contract.

B. Information on Market Structure

To provide shippers with a more useful picture of the structure of the market for both decisionmaking purposes and monitoring purposes, the Commission is expanding two of its reporting requirement regulations: the Index of Customers and the affiliate regulations.

1. Index of Customers

Pipelines currently file with the Commission, and post on their Internet web sites, on the first business day of each calendar quarter, an Index of Customers under existing section 284.106(c)(3) of the regulations, which provides the names of shippers holding firm capacity, the amount of capacity they hold, the applicable rate schedule, and the contract effective and expiration dates. The Commission is adding the following new information requirements to the Index of Customers, which is now section 284.13(c): the receipt and delivery points held under the contract and the zones or segments in which the capacity is held; the common transaction point codes; the contract number; a shipper identification number, such as DUNS; an indication whether the contract includes negotiated rates; the names of any agents or asset managers that control capacity in a

pipeline rate zone; and any affiliate relationship between the pipeline and the holder of capacity.

The Commission is requiring that pipelines report the receipt and delivery points and zones or segments in which the capacity is held so that the capacity path held by the shipper can be traced, and the data can be used to determine which shippers can compete in providing capacity on segments of the pipeline. The contract number and shipper identification number are needed on the Index of Customers, as well as on the report of capacity release transactions, so capacity can be traced through release transactions to reveal how much total capacity each shipper holds. In addition, in the current market, shippers may be using agents or asset managers to manage their capacity, and such managers may be given wide latitude over the way in which capacity is used. Requiring that pipelines disclose the names of the agents or asset managers will help to show the degree of control over pipeline capacity that an agent or asset manager may exercise. This will aid in the detection of potentially anticompetitive market dominance. Finally, to permit effective monitoring of the capacity held on pipelines, it is necessary to know any affiliate relationship between the pipeline and a shipper or a shipper's agent or asset manager in order to determine the total amount of capacity held by the parent entity.

The information in the Index of Customers that the Commission is requiring in this rule is different from the information that the Commission proposed in the NOPR to include in the Index of Customers. Essentially, as described below, the Commission is

requiring less information with respect to agency and affiliate relationships to be reported than the Commission proposed to require in the NOPR.

In the NOPR, the Commission proposed to require pipelines to report for each customer the names of any agents or asset managers that control 20 percent or more of capacity in a pipeline rate zone, as well as the rights of the agent or asset manager with respect to managing the transportation service. Several commenters objected to this reporting requirement.²³⁷

Dynegy indicates that it holds a number of agency arrangements with pipeline customers under which it sometimes provides an array of services, and which its competitors would want to replicate. Dynegy argues that if the breadth and depth of agency relationships are disclosed, an agent will be stripped of any competitive advantage it has gained through experience and commercial expertise.²³⁸ Dynegy also contends that to the extent that the market would learn of an agency relationship, the ability of that agent or asset manager to act on behalf of a large shipper without moving the market would be significantly reduced.

WGL, in its comments, states that it is unclear what purpose is served by this reporting requirement.²³⁹ WGL believes that if the information disclosed is limited to the details of operational rights, the release of such information may not be objectionable.

²³⁷Comments of Dynegy, WGL, and Coastal.

²³⁸Comments of Dynegy at 13.

²³⁹Comments of WGL at 15.

However, WGL contends that contracts between the shipper and the agent/asset manager may contain sensitive commercial information, and in many cases where the shipper is an LDC, such agreement is subject to local regulatory review. Coastal requests that the Commission limit the scope of this requirement to the disclosure of only the existence of an agent or asset manager, when known by the pipeline, not the rights of the agent or asset manager, which may be impossible for the pipeline to track.²⁴⁰

The Commission finds that asset manager reporting is needed to reveal potentially unhealthy market dominance by an asset manager that would not otherwise be apparent. However, the reporting of only the names of any asset manager or agent, without including the details of the asset manager/agency relationships, will be adequate for this purpose. Thus, the Commission is requiring pipelines to report the names of asset managers or agents, but not the agent's/asset manager's rights with respect to managing the transportation service. However, the Commission will require that all asset managers or agents be identified, not just those that manage 20 percent or more of the transportation service in a pipeline rate zone. The determination of which asset managers and agents meet this 20 percent threshold requirement may be too difficult to make in many instances. In addition, the Commission disagrees with Dynegy that reporting the names of asset managers or agents of customers will somehow reveal the identity of the particular customer the asset manager or agent is acting on behalf of during contract

²⁴⁰Comments of Coastal at 94.

negotiations. Since the asset manager or agent presumably would have several clients, the market would not know which client a given gas purchase would be for. There is no requirement that the actual capacity transactions arranged by the asset manager or agent be reported.

The Commission is also reducing the information required in the Index of Customers with respect to affiliates from what was proposed in the NOPR. In the NOPR, the Commission proposed to require that pipelines indicate, in the Index of Customers, any affiliate relationship between the pipeline and the holder of capacity, and any affiliate relationship between holders of capacity.

Several commenters objected to the requirement that pipelines identify affiliate relationships among holders of capacity.²⁴¹ PG&E objects to this requirement when such affiliate relationships involve third parties unrelated to the pipeline responsible for the posting.²⁴² PG&E and Williston Basin argue that pipelines do not have access to such information, nor the ability to obtain or ensure the accuracy of such information. Similarly, National Fuel maintains that it may not be practical for a pipeline to identify every affiliate relationship between a particular shipper and every other shipper using the pipeline's system.²⁴³ At a minimum, National Fuel argues, this requirement should be limited to major holders of capacity – perhaps those holding 20 percent of the pipeline's

²⁴¹Comments of PG&E, National Fuel, Dynegy, and Williston Basin.

²⁴²Comments of PG&E at 18-19.

²⁴³Comments of National Fuel Gas Supply at 4-5.

capacity -- and that the onus should be on the capacity holder to identify whether it is affiliated with the pipeline's other shippers. Dynegy, also, asserts that this requirement gives pipelines too much discretion to research their shipper's transactions.²⁴⁴

As a result of these comments, the Commission has reconsidered its proposal to require the reporting of third-party affiliates. The Commission agrees with the commenters that it may not be feasible for pipelines to accurately identify their customers' affiliates. Therefore, the Commission is requiring that pipelines identify only their own affiliates, and not affiliate relationships among customers.

Dynegy and others that object to the disclosure of customer names, receipt and delivery points and contract numbers required in the transactional reports in section 284.13(c) also object to the requirement that they be disclosed in the Index of Customers, on the same bases of confidentiality and burden. Some commenters argue that the transactional reports and the Index of Customers are duplicative.²⁴⁵

The rationale for including customer names, receipt and delivery points and contract numbers in the Index of Customers is essentially the same as it is for including such information in the transactional reports. The additional information being required in the Index of Customers, particularly the receipt and delivery points and zones or segments in which capacity is held, which raises the most concern with respect to burden

²⁴⁴Comments of Dynegy at 12.

²⁴⁵E.g., Comments of Williams.

for commenters, is necessary for shippers to determine who holds capacity, the amount, and where it is held. Such information reveals potential sources of capacity for shippers making purchase decisions, provides information on market concentration and structure, and will permit shippers to better monitor for potential undue discrimination or preference. The benefits and importance of requiring the posting of the additional data in the Index of Customers outweigh the concerns of the commenters about confidentiality, just as it does with respect to the transactional reports.

With respect to the burden of posting the additional information in the Index of Customers, some of the additional Index of Customer data – the affiliate indicator and the delivery points under the contract – are already reported or maintained for discounted transactions. Pipelines will simply have to add this and the other, new, data (contract number, shipper identification number, receipt points, whether the contract includes negotiated rates, and the names of any agent/asset manager) to the existing data sets for the current Index of Customers. In addition, as discussed above, the Commission has reduced the burden that some of the informational requirements for the Index of Customers proposed in the NOPR would otherwise have place on pipelines (i.e., the identification of affiliate and agent/asset manager relationships). In sum, the additional reporting burden with respect to the Index of Customers should not be too great given that the additional information, for the most part, is straightforward information that is a part of each shipper's contract.

Finally, the information required in the Index of Customers is not duplicative of the information in the transactional reports. The Index of Customers provides a snapshot view of who holds firm capacity on each pipeline that otherwise could not be obtained without continuously tracking every firm capacity transaction. Conversely, the transactional reports are necessary to provide the price information that is not included, and would be meaningless to include, in the quarterly Index of Customers.

2. Affiliate Regulations

The Commission is expanding its affiliate regulations to provide more information to permit monitoring and self-policing of affiliate transactions. The Commission is revising section 161.3(l) of the standards of conduct for interstate pipelines to specifically require that pipelines with marketing affiliates post certain information concerning their affiliates on their Internet web sites, and to update the information within three business days of any change.²⁴⁶ These revisions also will apply to pipelines with sales operating units.²⁴⁷ Under revised section 161.3(l), the Commission is requiring that pipelines post a list of the names of operating personnel and facilities shared by the interstate pipeline and its marketing affiliate. The pipelines currently provide this information in their tariffs,

²⁴⁶The regulation adopted here incorporates the changes in the affiliate regulations made previously in Docket No. RM98-7-000, Reporting Interstate Natural Gas Pipeline Marketing Affiliates on the Internet, III FERC Stats. & Regs. Regulations Preambles ¶ 31,064 (July 30, 1998), 63 FR 43075 (Aug. 12, 1998).

²⁴⁷18 CFR 284.286 (c) (requiring pipelines with sales operating units to comply with standards of conduct applicable to marketing affiliates).

under section 250.16(b)(1); however this new requirement will make such affiliate information easily available on the Internet.

The Commission also is requiring pipelines, under section 161.3(l), to post on their Internet web sites comprehensive organizational charts that include several types of information, set forth below. The Commission has adopted a similar requirement for the posting of organizational charts and job descriptions in the electric industry, to help monitor and protect against improper communications between transmission and wholesale merchant function employees.²⁴⁸

First, the pipeline must post an organizational chart showing the organizational structure of the parent corporation and indicating the relative position within the corporate structure of the pipeline and all marketing affiliates.

Second, the pipeline must post an organizational chart showing business units, job titles, job descriptions, and chain of command for all positions within the pipeline, including officers and directors. The pipeline need not include such information for clerical, maintenance, and field positions, since employees in those positions would not have access to information concerning the processing or administration of requests for service. The job titles and descriptions must include the employee's title, duties, and an indication whether the employee is involved in transportation or gas sales. Employees involved in transportation or gas sales include any member of the board of directors,

²⁴⁸See American Electric Power Service Corporation, 81 FERC ¶ 61,332 (1997), 82 FERC ¶ 61,131, order on reh'g, 83 FERC ¶ 61,357 (1998).

officers, managers, supervisors, and regulatory and technical personnel with duties involving day-to-day gas purchasing, marketing, sales, transportation, operations, dispatching, storage, or related activities.²⁴⁹ In addition, the pipeline must also include the names of supervisory employees who manage non-clerical employees involved in transportation or gas sales.

Third, for all employees shared by the pipeline and a marketing affiliate, the pipeline must post an organizational chart showing the business unit or sub-unit within the marketing affiliate organizational structure in which the shared employee is located, the employee's name, the employee's job title, and job description within the marketing affiliate, and the employee's position within the chain of command of the marketing affiliate.

The reporting requirements being adopted here are essentially the same general requirements proposed in the NOPR. However, the Commission has decreased the reporting burden that would have been required by the NOPR. In the NOPR, the Commission proposed to require pipelines to post detailed organizational charts, including detailed employee job descriptions, for the pipelines' marketing affiliates. In this final rule the Commission is not requiring organizational charts for the marketing affiliates, except to the extent that they share employees with the pipeline, and the

²⁴⁹Order No. 497-E, order on rehearing and extending sunset date, 59 FR 243 (January 4, 1994), FERC Stats. & Regs. 1991-1996 ¶ 30,958 at 30,996 (December 23, 1993) (defining "operating employee").

reporting requirement is limited to data regarding the shared employee. The Commission is making this change to conform the affiliate reporting requirements for pipelines to those required for the electric utilities.

Several commenters fully support the reporting requirements that were proposed.²⁵⁰ Dynegy maintains that these reporting requirements are a valuable tool to police pipeline affiliate activities, as well as a resource for contacting employees within a corporation. Several commenters also oppose these affiliate reporting requirements, particularly the requirement that pipelines post organizational charts and employee names.²⁵¹ Williston Basin objects to the posting of organizational charts, names, and job descriptions for marketing affiliates. Williston Basin argues that the Commission has never before imposed a marketing affiliate reporting requirement on pipelines that do not conduct business with the marketing affiliate. Williston Basin also maintains that requiring the names of pipeline and marketing affiliate employees to be posted on the pipeline's web site, even though their job requirements do not entail contact with outside parties, would violate the personal privacy of those employees.

Requiring that pipelines post shared personnel, organizational charts, job titles and descriptions, and the names of senior employees is essential to ensure that pipelines deal fairly with their customers. These reporting requirements will act to deter undue

²⁵⁰Comments of Dynegy, Indicated Shippers, and PUC of Ohio.

²⁵¹Comments of Williston Basin, Williams, and Tejas.

discrimination and preference, and will permit the market to monitor and self-police affiliate transactions.

In response to Williston Basin, the Commission clarifies that all of the marketing affiliate reporting requirements in Part 161, including the new requirements added here, apply only to pipelines that conduct transportation transactions with their marketing or brokering affiliates.²⁵² Also, as stated above, the Commission is not requiring the detailed organizational charts for marketing affiliates, to which Williston Basin objects, in all instances. Only where there are shared employees between the marketing affiliate and the pipeline is the pipeline required to post information regarding the shared employee's position within the marketing affiliate. The Commission further clarifies that it is requiring posting of the names of only senior employees. A pipeline will not be required to post the names of non-senior employees, so concerns about privacy for lower level employees are somewhat misplaced.

C. Information on Available Capacity

In section 284.8(b)(3) of the Commission's existing regulations, pipelines are required to post information about the amount of operationally available capacity at receipt and delivery points, on the mainline, in storage fields, and whether the capacity is

²⁵²18 CFR 161.1. However, as provided in section 161.1, the marketing affiliate reporting requirements in Part 161 apply not only to marketing affiliates, but also to pipeline sales operating units.

available directly from the pipeline or through capacity release.²⁵³ In new section 284.13(d)(1), being adopted here, the Commission is continuing to require that pipelines post this information, and is adding the following information on capacity availability to the information that is already collected: the total design capacity of the point or segment; the amount of capacity scheduled at each point on a daily basis; and information on planned and actual service outages that would reduce the amount of capacity available. The Commission expects that the pipelines will provide advance notice of planned outages or service disruptions so that shippers can plan for these events.

Information on the total design capacity of the point or segment, and the amount of capacity scheduled on a daily basis is needed for shippers to monitor capacity availability. With respect to the information on outages, while some pipelines currently post such information on outages, it is not currently a Commission requirement. Requiring pipelines to provide information on outages will enable shippers to better make decisions about their use of capacity because they will know whether the available capacity will be reduced on a particular day. Such information will also help in monitoring capacity withholding by revealing reasons for reductions in scheduled quantities.

These reporting requirements for available capacity are the same reporting requirements proposed in the NOPR. Some commenters, however, object to the

²⁵³18 CFR 284.8(b)(3); 18 CFR 284.10(b)(1)(iv) (1997), Electronic Delivery Mechanism Related Standards 4.3.6; 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.13.

additional reporting requirements on capacity availability,²⁵⁴ while others appear to object to the continuation of the existing reporting requirements on operationally available capacity.²⁵⁵

Specifically, several pipelines argue that it will be difficult to comply with the additional requirements for posting design and scheduled capacity because for some pipeline configurations, and for particular pipeline segments, capacity is not fixed, but is dependent on operating conditions or operational strategies that may vary depending on requests for service. For instance, Coastal states that on web-like systems, the design capacity at particular points or segments is a function of the usage of other parts of the system, which varies constantly, particularly with the implementation of three intraday nomination cycles.²⁵⁶ CMS Pipelines state that they do not have the computer and technology capability to provide the additional capacity information in real time. For example, they assert that field outages that affect capacity are not conveyed immediately to the EBB. CMS Pipelines also add that human intervention, judgment and decisionmaking can all affect the determination of available capacity.

More generally, CNG asserts that it cannot provide detailed information about available capacity over particular paths or segments, or in particular storage facilities, and

²⁵⁴Comments of Coastal, CMS Pipelines, and Williams.

²⁵⁵Comments of CNG, and Peoples.

²⁵⁶Comments of Coastal at 93.

lists a number of variables that influence the capacity available at any given moment.²⁵⁷

CNG argues that because such variables determine the level of available capacity at any given time, it is meaningless for pipelines to report calculated capacities throughout its system. In addition, some commenters appear to suggest that the Commission limit the existing reporting of operationally available capacity to key points, such as interconnections, market hubs, and points that are frequently constrained.²⁵⁸

In contrast, a few commenters argue that the Commission should require pipelines to post more information on available capacity than was proposed.²⁵⁹ For example, Dynegy maintains that shippers need information on design capacity, operationally available capacity, and actual and maximum flows, not only at all receipt and delivery points and on the mainline, but also at each point of constraint and segment. Dynegy also asserts that shippers need information on unsubscribed capacity and capacity under expiring or terminating agreements, and that they need such information at least 18 months in advance of when the capacity will become available. Similarly, Industrials request that the Commission require pipelines to post on the Internet detailed, rolling information regarding capacity becoming available over the next 18 months. Exxon, also, requests that the Commission require the posting of capacity under contracts that are due to expire in four months.

²⁵⁷Comments of CNG at 33-34.

²⁵⁸Comments of Peoples at 15 and Philadelphia Gas Works at 1.

²⁵⁹E.g., Comments of Dynegy at 1-7.

Several clarifications of this reporting requirement are needed to respond to the commenters' concerns. First, as stated above, the Commission's current regulations require pipelines to post operationally available capacity at receipt and delivery points, on the mainline, and in storage fields.²⁶⁰ The Commission did not propose in the NOPR to change these requirements, and in this rule is not modifying such requirements. Pipelines have been able to comply with the regulations requiring the reporting of operationally available capacity, and thus, there is no reason to modify such requirements. Pipelines must continue to report available capacity as required in the Commission's existing regulations, which necessarily involves pipelines taking into account operational variables.

Second, pipelines have information on the amount of capacity scheduled at each point or segment, and, therefore, should be able to post that data on a daily basis. In fact, GISB Standard 1.3.2 requires pipelines to inform shippers of scheduled quantities. However, the Commission is not requiring that pipelines post scheduled capacity at all points and segments. If, as some pipelines argue, it is difficult for them to provide scheduled capacity on segments of their systems, they need only post scheduled capacity for their receipt and delivery points. The Commission is requiring the posting of

²⁶⁰18 CFR 284.8(b)(3); 18 CFR 284.10(b)(1)(iv) (1997), Electronic Delivery Mechanism Related Standards 4.3.6; 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.13.

scheduled capacity for either receipt and delivery points, or segments, whichever makes the most sense for a particular pipeline system.

Third, the Commission understands that it may be difficult for some pipelines to calculate the total design capacity of each point or segment on its system, due to operational or usage variables or particular system configurations. In those instances, pipelines must post design capacities for the most common operating conditions of their systems, such as peak period or off-peak period. In addition, the Commission clarifies that the posting of the total design capacity of the points or segments is not a daily posting requirement. Rather, pipelines must update this information from time-to-time as changes in design capacity occur.

Finally, the Commission does not find it necessary to require pipelines to provide even more detailed information on design capacity and operationally available capacity than the Commission is requiring in this rule, or to provide information on the future availability of capacity. Currently, shippers can obtain information on firm capacity that will be coming available in the future by reviewing the Index of Customers, which includes contract expiration dates. With respect to requiring more detailed capacity information, including flow data, at not just receipt and delivery points, but also at constraint points and segments, as Dynegy suggests, the Commission finds that the reporting of scheduled capacity at each receipt and delivery point is sufficient, and that shippers should be aware of which points or segments are constrained.

D. Coordination With GISB Standardization Efforts

The Commission recognizes that pipelines have just completed preparing their systems for the Year 2000 and are in the process of making changes to comply with Commission requirements to transfer data from Electronic Bulletin Boards to Internet web sites by June 1, 2000. The Commission, therefore, will require pipelines to implement the new data reporting requirements by September 1, 2000.

Pipelines are required to provide much of the information in the revised reporting requirements by posting the information on their Internet web sites and in downloadable file formats. The industry, through the Gas Industry Standards Board (GISB), has developed, and is in the process of improving, standards for providing currently required information both on pipeline web sites and through downloadable file formats, using Electronic Data Interchange ASCX12 (EDI) formats.²⁶¹ GISB also is examining whether to provide such downloads in flat ASCII file formats as well. GISB already has developed standards and the pipelines are posting some of the information in the revised regulations, such as capacity release information and operationally available capacity. Pipelines will continue to post that information pursuant to the GISB standards.

Ultimately, GISB needs to develop standards for the new reporting requirements (including pipeline firm and interruptible transportation transactions, design capacity, constraint information, and scheduled capacity) both for the presentation of the

²⁶¹See Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587-I, 63 FR 53565, 53569-75 (Oct. 6, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,067, at 30,737-46 (Sept. 29, 1998).

information on pipeline web sites and the provision of the information in Electronic Data Interchange ASCX12 (EDI) or ASCII file formats.

The Commission encourages GISB to try and to complete the process of standardization in time for the September 1, 2000 implementation date. But the Commission recognizes that such a schedule may be ambitious given the other changes to electronic communication GISB is now in the process of developing. Because the provision of the new information is important both to improve market transparency and for monitoring, the Commission will require pipelines to provide this information in non-standardized formats in the event GISB is unable to develop the datasets in time for September 1, 2000 implementation. Pipelines, however, will not have to develop individual EDI file formats for the information during the period when GISB is developing the standards. Pipelines only will have to post the information on their web sites and provide flat ASCII file downloads for the relevant information. In addition, the Commission will issue in the near future revisions to its instruction for the electronic filing of the Index of Customers report to accommodate the new information required by this rule.

The revised reporting requirements also call for the provision of both shipper names and a unique numeric identifier for each shipper. These requirements apply to both the Internet postings and the electronic file downloads. This requirement represents a change from the current practice under the GISB standards of providing only numeric identification in electronic file downloads. The industry, through GISB, has chosen to

use the numbers developed by Dun & Bradstreet (D&B) as the numeric identifier for shipper names (DUNS numbers). Where pipelines use numeric identifiers in electronic communications without the accompanying shipper name, the Commission has required pipelines to provide a table that cross-references shipper names with the applicable DUNS numbers.²⁶² GISB has worked out an arrangement with D&B to verify the accuracy of the DUNS numbers used by pipelines and to post a cross-reference table on the GISB web site.

The Commission finds that the use of numeric identifiers for shippers is of great value, particularly for electronic processing, because electronic identifiers make electronic processing easier and eliminate confusion that may be introduced through the use of names alone, such as different spellings or abbreviations for the same entity. The Commission also appreciates GISB's agreement with DUNS to provide for verification of pipeline DUNS numbers, because that improves the accuracy of these numbers. The Commission, therefore, is requiring that all pipelines which have not yet had their DUNS numbers verified by D&B submit their numbers to D&B for verification.

The Commission, however, is concerned with the current GISB standards which require the reporting of DUNS numbers only for electronic file downloads and do not contain a field for shipper names. While the GISB cross-reference table is extremely useful for associating the names and DUNS numbers, the Commission has noticed that

²⁶²18 CFR 284.10 (c)(3)(iii) (existing regulations) 18 CFR 284.13 (c)(3)(iii) (revised regulations).

with respect to almost all pipelines, the cross-reference table generally omits a small, but not insignificant, percentage of shippers, who are presumably new shippers on the system. One solution for this problem would be to require pipelines to make immediate updates to the cross-reference table when new shipper names are added. But it would appear difficult and burdensome for the pipelines to institute procedures to ensure that whenever a new shipper is added to their systems, they remember to inform GISB of the addition to the cross-reference table. The need for such frequent changes also will pose administrative burdens for GISB, as well as make Commission monitoring of pipeline compliance more burdensome.

Due to the difficulties and burdens of maintaining an accurate cross-reference table, the Commission has determined instead to require pipelines to provide both a name and a number in both their Internet postings and downloadable files. When GISB next updates its standards for electronic file downloads, it needs to include fields so that pipelines can include both the shipper name and the DUNS numbers in the electronic file. Until those changes occur, the pipelines must continue to use the cross-reference table and to update their information on that table at monthly intervals.

V. OTHER PIPELINE SERVICE OFFERINGS

In the NOPR, the Commission sought comment on whether, in light of the changes occurring in the natural gas market, the Commission should revise or eliminate the right-

of-first refusal (ROFR)²⁶³ and revise its current regulations with respect to non-conforming service agreements²⁶⁴ to permit pre-approval of negotiated terms and conditions of service between pipelines and shippers. As discussed below, the Commission finds that some narrowing of the ROFR is needed so that it interferes as little as possible with the efficiency of the market while continuing to protect captive customers. As discussed earlier, the Commission has determined that further inquiry into the question of pre-approved negotiated terms and conditions is needed. In light of the decision not to move forward with pre-approved negotiated terms and conditions, the Commission will discuss several aspects of this decision, including its policies regarding non-conforming service agreements and the interrelation between negotiated terms and conditions of service and negotiated rates.

A. Right of First Refusal

In the NOPR, the Commission considered whether any changes to the right of first refusal and its five-year term matching cap are appropriate in light of the changes that have occurred in the marketplace since implementation of Order No. 636. Upon consideration of the comments, the Commission has decided to retain the right of first refusal with the five-year term matching cap, but narrow the scope of the right. In the future, the right of first refusal will apply only to maximum rate contracts for 12 or more

²⁶³18 C.F.R. § 284.221(d) (1999).

²⁶⁴18 C.F.R. §§ 154.1(d) and 154.112(b) (1999).

consecutive months of service. Because the right of first refusal will apply only to maximum rate contracts, there will be no regulatory right of first refusal for contracts containing negotiated rates. This modification is consistent with the purpose of the right of first refusal to protect the historical service of long-term captive customers. This limitation on the right of first refusal strikes the appropriate balance between the need to protect captive customers and the need to balance the risks between pipelines and existing shippers.

1. Background

In Order No. 636, the Commission amended its regulations to permit pre-granted abandonment of transportation contracts. In order to protect captive customers from the pipelines' monopoly power, and permit them to continue to receive the historical service upon which they had relied, the Commission conditioned pre-granted abandonment on the right of first refusal.²⁶⁵ Pursuant to the right of first refusal, an existing shipper with a long-term firm contract can retain its service from the pipeline by matching the rate and length of service of a competing bid for that service. The rate is capped by the pipeline's maximum tariff rate, and the requirement that the existing shipper must match the length of the contract term of a competing bid is limited to a contract length of five years.²⁶⁶ In

²⁶⁵18 C.F.R. § 284.221(d) (1999).

²⁶⁶In Order No. 636-A, the Commission adopted a term matching cap of 20 years. In UDC v. FERC, the court approved the basic right of first refusal and approved the concept of a term matching cap, but found that the Commission had not adequately
(continued...)

UDC v. FERC,²⁶⁷ the court found that the right of first refusal mechanism with a cap on the contract length was an adequate means of protecting customers from pipelines' market power.

In the NOPR, the Commission explained that increased competition in the commodity and capacity markets since Order No. 636, affords greater protection to shippers from monopoly power. Further the Commission observed that since restructuring, some small LDCs no longer have to hold capacity on the pipeline in order to receive gas, and that, in fact, many LDCs have chosen not to hold capacity on pipelines. The Commission suggested that these changes could indicate that a right of first refusal is no longer necessary to protect shippers.

The Commission was also concerned that the right of first refusal with the five-year matching cap provides a disincentive for an existing shipper to enter into a contract of more than five years, and results in a bias toward short-term contracts. Therefore, the Commission proposed in the NOPR to eliminate the term matching cap from the right of first refusal. In addition, the Commission stated that it would consider other options for modifying the right of first refusal, including whether it should be eliminated in its

²⁶⁶(...continued)
explained the 20-year cap. In Order No. 636-C, the Commission concluded that a matching cap of 5 years was appropriate given the trend to shorter contracts.

²⁶⁷88 F.3d 1105, 1139 (D.C. Cir. 1996), cert. denied, 117 S. Ct. 1723 (1997).

entirety, whether the length of the term matching cap should be changed, and whether a right of first refusal should be a matter of negotiation between the parties.

In the comments on the NOPR, the proposal to eliminate the five-year term matching cap was generally opposed by shippers and shipper groups,²⁶⁸ as well as by several state agencies.²⁶⁹ These commenters argue that, contrary to the Commission's assertions in the NOPR, increased competition does not afford customers sufficient protection from the pipelines' market power. They state that the Commission itself acknowledges that pipelines still possess market power in the long-term market where the right of first refusal is applicable, and for that reason did not propose to eliminate rate regulation in the long-term market. They argue that removing the five-year cap would require the shipper to commit to capacity for a term well beyond what would be prudent in light of the risks of doing business in the evolving market place. In addition, they argue that eliminating the right of first refusal or the five-year cap is not legally justified in light of the court's decision in UDC v. FERC.

²⁶⁸For example, AGA, APGA, Allied Signal, American Forest & Paper Assoc., Amoco Energy Trading Co., et al., Atlanta Gas Light, Brooklyn Union Gas Co. and KeySpan Gas, Colorado Springs Utilities, Columbia LDCs, Consolidated Edison Co. of New York, the Fertilizer Institute, Florida Cities, FPL Group, and New England Gas Distributors.

²⁶⁹E.g., Illinois Commerce Commission, Minnesota Department of Public Service, Pennsylvania Office of Consumer Advocate and Pennsylvania Public Utility Commission,, New York Public Service Commission, Wisconsin Public Service Commission, Ohio Public Utilities Commission.

Several of these commenters argue that the Commission should strengthen the right of first refusal by reducing the term-matching cap.²⁷⁰ For example, ConEd argues that a one-year cap is appropriate because LDCs must be able to assemble economically priced packages of transportation capacity without putting reliability at risk or needlessly creating stranded costs. Several parties, including Brooklyn Union/Keyspan and Consolidated Edison of New York, ask the Commission to enhance the right of first refusal by clarifying that an existing shipper may exercise its right of first refusal as to a geographic portion of the existing contract.

On the other hand, the pipelines²⁷¹ argue that the right of first refusal should be eliminated because it no longer serves any purpose since increased competition affords customers protection from monopoly power. If the right of first refusal is not eliminated in its entirety, they argue that at a minimum, the term-matching cap should be removed. These parties assert that the right of first refusal reduces competition and distorts the competitive environment by denying the pipeline and a willing third party the right to contract for longer than the cap period. Further, they argue that the right of first refusal places disproportionate risks on the pipelines because the pipeline must bear the risk of

²⁷⁰For example, Brooklyn Union and Keyspan Gas, Consolidated Edison Co. of New York, and New England Gas Distributors argued that the term matching cap should be reduced to one year. The Pennsylvania Office of Consumer Advocate and the Pennsylvania Public Utility Commission suggested shortening the matching cap to two years, and revisiting the issue periodically. PSE&G suggested shortening the term to 2-3 years. AGA also suggested shortening the term.

²⁷¹E.g., INGAA, Williams, Tejas, Williston, Enron Interstate Pipelines,

standing ready to serve the existing shipper indefinitely, while the shipper has no such obligation.

2. Discussion

The purpose of the right of first refusal is to protect captive long-term customers from the pipelines' exercise of monopoly power.²⁷² It is based on the customer's reliance on the pipeline for its historical service.²⁷³ It protects existing customers by providing them with the right to continue their existing service by matching the highest competitive bid for the service, up to the maximum rate and up to a period of five years. At the same time, by requiring that existing customers match competitive bids, the right of first refusal recognizes the role of market forces in determining contract price and term.

As markets become more competitive, and the secondary market continues to develop, it may become unnecessary to protect any customer with a right of first refusal. However, upon consideration of the comments, the Commission has determined that it cannot at this time reach the conclusion that all long-term shippers have sufficient competitive options to warrant elimination of the right of first refusal in its entirety. The Commission, therefore, will retain a right of first refusal and will retain, for the present, the five-year matching cap. However, the right of first refusal will apply in the future only to maximum rate contracts for 12 or more consecutive months of service.

²⁷²UDC v. FERC , 88 F.3d 1105, 1140 (D.C. Cir. 1996), cert denied, 117 S. Ct. 1723 (1997); Order No. 636-C, 78 FERC ¶ 61,186 at 61,772-773 (1997).

²⁷³Id.

Limiting the right of first refusal to maximum rate contracts of 12 or more consecutive months of service is consistent with its original purpose to protect long-term captive customers from the pipeline's monopoly power. If the customer is truly captive and has no alternatives for service, it is likely that its contract will be at the maximum rate. Shippers that are not captive customers and have alternatives in the marketplace do not need the protection of the right of first refusal.

In addition, the ROFR will apply only when the contract provides for 12 or more consecutive months of service. This is a different result than the Commission reached in North American Energy Conservation, Inc. v. CNG Transmission Corp.²⁷⁴ under the current regulations, which provide that the right of first refusal applies to "a contract with a term of one year or more."²⁷⁵ In that case, the Commission concluded that the right of first refusal applied to a contract with a duration of 15 months that provided for two noncontinuous periods of seasonal service, each one of which was for less than 12 months. The Commission held that, under the current regulations, it was the term of the contract rather than the term of the service that determined the applicability of the right of first refusal. In the future, the right of first refusal will apply only when the contract provides for at least 12 consecutive months of service; it will be the term of the service rather than the term of the contract that will determine the applicability of the right of first

²⁷⁴88 FERC ¶ 61,255, reh'g, 89 FERC ¶ 61,122 (1999).

²⁷⁵18 C.F.R. § 284.221(d)(2).

refusal. Again, this is consistent with the purpose of the right of first refusal to protect long-term captive customers. Seasonal service is short-term service, even if the contract providing for the service is of a duration of more than a year, and the right of first refusal is intended to protect long-term customers.

With this modification captive customers still will be able to continue to receive their historical service as long as they pay the maximum rate. And, the pipeline is not disadvantaged by the right of first refusal if the contract is at the maximum rate. However, if a shipper has sufficient alternatives that it can negotiate a rate below the just and reasonable rate, it should not have the protection afforded by the right of first refusal. In these circumstances, the pipeline should be able to negotiate with other interested shippers. This limitation on the right of first refusal strikes the appropriate balance between the need to protect captive customers and the need to better balance the risks between the shipper and the pipeline.

The maximum rate that the existing shipper must meet in order to exercise its right of first refusal may be higher than its current rate. The Commission's regulations provide that a shipper whose contract is expiring is entitled to renew that contract by matching the highest bid up to the maximum rate,²⁷⁶ but, there is nothing in the right of first refusal that guarantees that the maximum rate will remain the same. The Commission recognized in its recent Policy Statement concerning Certification of New Interstate Natural Gas

²⁷⁶ 18 C.F.R. § 284.221(d) (1999).

Pipeline Facilities (Certificate Policy Statement),²⁷⁷ that a shipper exercising its ROFR could be required to match a bid up to a maximum rate higher than the historic maximum rate applicable to its capacity in certain limited circumstances: when a pipeline expansion has been completed and an incremental rate exists on the system; the pipeline is fully subscribed; and there is a competing bid above the maximum pre-expansion rate applicable to existing shippers.²⁷⁸

The existing customers should not be required to subsidize expansion projects that are implemented during the term of their contracts. While their contracts are in effect, it would be inequitable to raise their rates to include the costs of expansion projects that will not be used to provide them with service. Thus, it is logical to price the new project incrementally and without subsidies from the rates of the existing shippers. However, when the existing customer's contract expires, the existing customer should be treated similarly to new customers for pipeline capacity, who face rates higher than the pre-expansion historic rate.²⁷⁹ Under the policy conditions established by the

²⁷⁷Docket No. PL99-3-000, 88 FERC ¶ 61,227 (1999).

²⁷⁸Under this procedure, the pipeline cannot require the existing shipper to pay a rate higher than that of the competing bidder. For example, if the historic maximum rate is \$1/MMBtu, the maximum rate the existing shipper has to match is \$2/MMBtu, and the competing bid is \$1.50/MMBtu, the pipeline must sell the capacity to the existing shipper if it is willing to match the \$1.50 bid.

²⁷⁹Cf. PG&E Gas Transmission, Northwest Corporation, 82 FERC ¶ 61,289, at 62,124-26 (1998) aff'd Washington Water Power Co. v. FERC, No. 98-1245 (D.C. Cir. Feb. 1, 2000)(for permanent releases of capacity taking place after an expansion, the replacement shippers should pay the same rate as the expansion shippers).

Commission (fully subscribed expansion, at least one bid above the existing rate, and a rate mechanism established in advance), there would be insufficient capacity to satisfy all the demands for service on the system. When insufficient capacity exists, a higher matching rate will improve the efficiency and fairness of capacity allocation, within the limits imposed by cost-of-service ratemaking, by allowing new shippers who place greater value on obtaining capacity than the existing shipper to better compete for the limited capacity that is available.

The logic for using a higher matching rate would not apply if the system were not fully utilized, and in those circumstances, the existing customer could exercise its right of first refusal by agreeing to pay the historic maximum rate. This protects an existing captive customer against the exercise of market power by the pipeline because the pipeline cannot insist on the shipper paying a higher rate unless its expansion is fully subscribed and there is another bid for capacity at a rate above the historic maximum rate charged the existing shipper. These conditions ensure that the pipeline is unable to use its market power over captive customers to withhold capacity from the market to raise price. Price will exceed the current maximum rate charged the existing shipper only when a higher price is needed to allocate scarce capacity.

As the Commission explains in the Certificate Policy Statement,²⁸⁰ to adjust the maximum rate applicable to shippers exercising their ROFR in these circumstances, the

²⁸⁰Docket No. PL99-3000, Order Clarifying Statement of Policy.

pipeline would have to establish a mechanism for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost-of-service.²⁸¹ The mechanism can be established either through a general section 4 rate case or through the filing of pro forma tariff sheets which would provide the Commission and the parties with an opportunity to review the proposal prior to implementation. The Commission would review the proposed mechanism to determine how well it achieves the following objectives: capacity pricing that permits as efficient an allocation of capacity as is possible under cost-of-service ratemaking; protection against the exercise of market power by the pipeline (through withholding of capacity, for example, or the potential for skewed bidding); protection against the pipeline's overrecovery of its revenue requirement; and equity of treatment between shippers with expiring contracts and new shippers to the system seeking comparable service.

Application of this approach could lead to rates for shippers exercising their ROFR that are higher than their existing vintaged rate. But this will occur only if the preconditions are met -- the pipeline is full and there is a competing bid higher than the pre-expansion rate so that a higher rate is needed to allocate available capacity -- and the Commission has accepted the pipeline's mechanism for determining rates as just and reasonable.

²⁸¹Cf. Viking Gas Transmission Company, 89 FERC ¶ 61,204 (1999) (rejecting tariff filing to raise matching rates under a ROFR where, among other things, the filing did not readjust existing and expansion rates).

In the Certificate Policy Statement, the Commission explained that it is important for the rates for the new capacity to send the correct price signals so that shippers can decide whether the new capacity is really needed. As the Commission further explains in its clarification order in that proceeding, there is tension between sending efficient pricing signals to expansion customers and to customers whose contracts are expiring, while remaining within the pipeline's revenue requirement. There may be a number of ways to recompute rates to effectively balance these interests. The Appendix to that order provides two examples of potential approaches to the recomputation of rates, one in which the expansion rate is recomputed to establish the maximum matching rate and the other where the system average rate is used as the matching rate. Under these approaches, as contracts of existing shippers expire, the costs and contract demand represented by these contracts are reallocated between the existing and expansion service without changing the pipeline's overall revenue requirement.

The Commission will not change the length of the term matching cap at this time. The Commission concluded in Order No. 636-C that a five-year cap was appropriate given the evidence in that record of industry trends in contract length.²⁸² The record there showed that five years was the median length of long-term contracts entered into since

²⁸²Order No. 636-C, 78 FERC at 61,773-74.

January 1, 1995.²⁸³ None of the commenters presented evidence to support the conclusion that a five year contract is atypical in the current market.²⁸⁴

Further, the Commission will not enhance the right of first refusal by holding that it can be exercised for a geographic portion of the existing contract, as requested by several commenters. The purpose of the right of first refusal is to protect the captive customer's historical service, and therefore it should apply only when the existing shipper is seeking to contract for its historical capacity. The right of first refusal is a limited right and it was never intended to permit shippers to increase or change their service.²⁸⁵ It is intended to be a means of defense against pipeline market power, not a mechanism to award an existing shipper a preference over a new shipper for different service.

In Order No. 636-B, the Commission clarified that the right of first refusal permits the existing capacity holder to elect to retain a volumetric portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to

²⁸³78 FERC at 61,774.

²⁸⁴Several commenters suggested that the Commission should take additional evidence on current contract length and reduce the length of the cap if that evidence warrants. See, e.g., comments of New England Gas Distributors. The Commission could undertake this analysis of industry trends in a future proceeding, but will retain the five-year cap for the present.

²⁸⁵As the Commission stated in *Williams Natural Gas Company*, 65 FERC ¶ 61,221 at 62,013 (1993), "the character of the service being provided under the expiring contract cannot be changed through use of the right of first refusal."

the remainder of the service.²⁸⁶ The Commission has explained that this is intended to ensure against the inefficient or unnecessary retention of capacity at the expiration of the contract.²⁸⁷ Unbundling has reduced the role of LDCs in providing transportation service. In 1998, over 80 percent of industrial users purchased their capacity directly from the pipeline or from marketers rather than from an LDC.²⁸⁸ Allowing LDCs to decrease their contractual volumes when they exercise the right of first refusal makes this capacity available to industrials and marketers. Thus, under the right of first refusal, if the LDC's market shrinks because its former sales customers are purchasing their own gas in the wholesale market, the LDC can reduce the volumes it has under contract.

However, Order No. 636 did not include within the right of first refusal the option to contract for a geographic portion of the historical capacity, and permitting an existing shipper to exercise its right of first refusal for a geographic portion of its historical service is not consistent with its purpose. A shipper that can terminate a geographic portion of its historical service must have alternatives in the marketplace that can substitute for its historical service, and therefore is not a captive customer that requires the protection of the right of first refusal. In its comments, Con Ed gives an example of a shipper that has a contract for service from the pipeline's production area to points in the market area, and

²⁸⁶Order No. 636-B at 30,634-35.

²⁸⁷Williams Natural Gas Co., 83 FERC ¶ 61,052 at 61,299 (1998).

²⁸⁸Energy Information Administration, Natural Gas Annual 1998, 35-37, 39, 41 (October 1999).

argues that the shipper should be able to retain its right of first refusal to capacity in the market area without being required to retain capacity in the production area. In this example, the shipper clearly has competitive options for transporting its gas and does not need the protection of a right of first refusal to protect its historical service.

Moreover, permitting the exercise of the right of first refusal for a geographic portion of the historical capacity could leave the capacity unused and thus burden the pipeline and its other customers with the cost of this unused capacity. This is the significant distinction between permitting a shipper to exercise its right of first refusal for a portion of the contractual volumes and permitting a shipper to exercise its right of first refusal for less than the full length of haul. With the development of the pipeline grid, the need to hold capacity to access traditional supply areas has diminished and thus there is more likelihood that reductions in geographic capacity will lead to unused capacity on some segments. In contrast, exercise of the right of first refusal for less than the full contractual volume is unlikely to have the same impact on the pipeline and its shippers because with retail unbundling that capacity is likely to be contracted to move gas to the end-users previously served by the LDC. Gas consumption has not been shrinking, rather the contracting patterns have been changing.

Therefore, maintaining the Commission's current policy and not expanding the right of first refusal beyond its original scope as set forth in Order No. 636 strikes the appropriate balance between protecting the historic service of the captive customer and not burdening the pipeline and its other customers with unused capacity.

The Commission's ruling that a shipper cannot exercise its right of first refusal for a portion of its length of haul is also consistent with the rationale of the court's decision in Municipal Defense Group v. FERC.²⁸⁹ In that decision, the court upheld the Commission's approval in Texas Eastern Transmission Corp.,²⁹⁰ of a proposal by the pipeline to award new capacity on the basis of a net present value determination. The Commission held that while the small customers had special treatment for their existing service,²⁹¹ they must compete on an equal basis with other customers for additional capacity. The court agreed, and stated that there was no reason to extend the special treatment given to small customers beyond their existing service in order to enable them to increase their capacity at a subsidized rate. Similarly, there is no basis for permitting customers with a right of first refusal to use that right to obtain an advantage over other customers in seeking to change their service to a shorter haul.

Several parties ask the Commission to clarify that shippers who have rollover or evergreen clauses in their contracts have the right to terminate a volumetric portion of that contract and exercise their right of first refusal with regard to the remaining portion of the

²⁸⁹170 F.3d 197 (D.C. Cir. 1999).

²⁹⁰79 FERC ¶ 61,258 (1997), reh'g, 80 FERC ¶ 61,270 (1997).

²⁹¹Small customers received a discounted rate on the pipeline pursuant to a settlement in the pipeline's Order No. 636 proceeding, and argued that the net present value method would be prejudicial to them because the value of their bids would be less than the value of bids of larger customers paying a higher rate.

contract.²⁹² These parties state that clarification is necessary because certain pipelines have taken the position that the right of first refusal protects only shippers whose contracts do not contain rollover or evergreen clauses. The commenters state that these pipelines have concluded that while the right of first refusal permits a customer to renew its contract for less than its full MDQ, this right does not extend to a customer with a rollover contract. The commenters state that clarification of this issue is necessary at this time because many LDC long-term contracts will be expiring over the next few years.

There are two possible sources of a shipper's right of first refusal. First, shippers have the right of first refusal as provided in the Commission's regulations. Thus, all shippers with a qualifying contract, (i.e., a contract of 12 months or more and, in the future, at the maximum rate), can continue to receive their service from the pipeline by matching the rate, up to the maximum rate, and the length of service, up to a period of five years, of a competing bid for that service. Under the right of first refusal conveyed by Section 284.221(d) of the regulations, shippers always have this regulatory right of first refusal, regardless of the provisions of their contract.

Second, a pipeline and its shippers may agree to include a right of first refusal rollover or evergreen clause in their contracts. If a contractual right of first refusal, rollover or evergreen clause would allow the shipper to exercise a right of first refusal in situations where the regulatory right would not apply, the shipper may rely on its contractual rights

²⁹²See comments of AGA and Con Ed.

in lieu of the regulatory right of first refusal. The choice is for the shipper to make. But, the shipper always has, at a minimum, the regulatory right of first refusal. As the Commission recently stated, “a ROFR is a regulatory right that may achieve the same purpose as a contractual rollover, but it is a right guaranteed by the regulations and not dependent on the contract.”²⁹³ Under the right of first refusal in Section 284.221(d), which is an exercise of the Commission's abandonment authority under NGA Section 7(b), a contractual right of first refusal may broaden the regulatory right of first refusal, but it may not narrow it.

The regulatory right of first refusal includes the right of the existing shipper to elect to retain a volumetric portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to the remainder of the service.²⁹⁴ Therefore, the Commission clarifies that a customer with a contract that qualifies for a regulatory right of first refusal may exercise that regulatory right for a volumetric portion of the capacity, regardless of whether the contract contains a rollover or evergreen clause.

Existing discounted long-term contracts that are now subject to the right of first refusal will be grandfathered, and the right of first refusal will apply at their expiration. However, the new rate limitation will apply to any of the contracts that are re-executed and, therefore, the right of first refusal will not apply if the re-executed contracts are not

²⁹³North American Energy Conservation, Inc. v. CNG Transmission, 88 FERC ¶ 61,255 at 61,809 (1999).

²⁹⁴Order No. 636-A, FERC Stats&Regs (1991-1996) ¶ 30,950 at 30,635 (1992).

at the maximum rate. The grandfathering of current contracts gives all shippers notice of the new limitation, and the opportunity to re-execute their current contracts in view of this change. Further, the provisions of the pipelines' current tariffs will continue to govern the right of first refusal process until the pipeline files revised tariff sheets to limit the right of first refusal consistent with this discussion.

B. Negotiated Terms and Conditions of Service

In the Commission's policy statement on Alternatives to Traditional Cost-of-Service Ratemaking,²⁹⁵ the Commission set forth its policy permitting pipelines the flexibility to negotiate rates so long as the shipper continued to have the option of choosing recourse service from the pipeline. The availability of a recourse service at just and reasonable rates was considered to provide reasonable protection against the exercise of market power. But the Commission at the time expressed concern about whether to permit individual negotiation of terms and conditions of service and requested further comment on whether such flexibility should be permitted. In the NOPR, the Commission proposed to permit pipelines to file tariff provisions providing for pre-approved authority to negotiate terms and conditions of service without making a separate tariff filing, so long as the pipeline adhered to a series of requirements intended to protect against degradation of recourse service.

²⁹⁵ Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), 74 FERC 61,076 (1996).

There was a significant split among the commenters on this issue. Pipelines and LDCs strongly supported the implementation of negotiated terms and conditions of service as ways in which pipelines could attract new customers, particularly gas fired electric generation and industrial customers.²⁹⁶ INGAA asserts, for instance, that gas fired electric generation has service requirements that differ from those provided in typical tariff-based services. AGA similarly asserts that permitting negotiation of services will permit pipelines to tailor services to fit the different circumstances of individual customers. Those supporting pre-approval for negotiated terms and conditions maintain that the Commission can provide adequate oversight to avoid undue discrimination, degradation of recourse service, and reduced competition.

Those on the other side were equally vociferous in opposing pre-approval for negotiated terms and conditions of service.²⁹⁷ These parties argue that the need for negotiated terms and conditions has not been demonstrated, because open access tariffs have been successful in serving all types of customers, and that even without pre-approval for negotiated terms and conditions of service, the electric generation market has shown the greatest growth of any natural gas consumption segment. These parties argue that allowing pipelines to negotiate terms and conditions of service gives rise to significant

²⁹⁶See Comments of AGA I, INGAA, Southern Natural, Williams, Coastal Companies, Enron Capital and Trade.

²⁹⁷See Comments of Amoco Energy Trading, Arkansas Gas Consumers, Dynegy, Indicated Shippers, NGSA, Process Gas Consumers Group, PSC Wisconsin.

dangers to competitive markets, including the danger of discrimination in pricing, timing, and terms of service and that negotiated terms and conditions exacerbates affiliate advantages, permits pipelines to degrade recourse services, and harms the secondary market which depends on the sale of a uniform product. Moreover, they argue that the protections proposed by the Commission to avoid problems created by negotiated terms and conditions of service raise problems of their own and will not prevent the degradation of recourse service. These parties assert that instead of permitting negotiated terms and conditions, the Commission should continue to enhance the flexibility of tariff services.

The Commission has determined not to provide pipelines, at this time, with authority to file for pre-approval of the right to negotiate terms and conditions of service with individual customers. Given the changes occurring in the marketplace, it is not yet clear that pre-approval for negotiated terms and conditions is necessary. Although pipelines and some gas fired generators support allowing negotiation of terms and conditions of service that will directly address the generators' service needs,²⁹⁸ other generators are not convinced that such negotiation flexibility is necessary or that it outweighs the risks of discrimination to those not receiving the negotiated services.²⁹⁹ Pipelines also have been able to create open access tariff-based services with enhanced flexibility for scheduling and handling imbalances without having to negotiate terms and

²⁹⁸See Comments of Sithe, Sempra Energy, EEI.

²⁹⁹See Comments of Midland, Florida Cities, Dynegy, FPL.

conditions of service with individual shippers.³⁰⁰ Indeed, in this rule, the Commission is requiring that pipelines provide imbalance management services that will better enable all customers to deal with the potential risks of imbalance penalties.

The negotiation of terms and conditions of service further is directly related to the question whether the Commission needs to revise fundamental aspects of its regulatory policy to accommodate a dual market structure in which some shippers with sufficient alternatives and negotiating leverage want to negotiate rates and terms and conditions of service while other shippers remain captive, still subject to the pipeline's market power and to undue discrimination. The development of a two-track regulatory model, as discussed earlier, requires further study of the interrelation between various aspects of Commission regulatory policy, such as whether rates should continue to support pipeline revenue requirements and how rates should be designed in a dual market to protect captive customers.

In light of the questions about the need for and effects of negotiated terms and conditions and the interrelation between negotiated terms and conditions of service and other long-term regulatory issues that were not the subject of this proceeding, the Commission has decided not to move forward at this time to provide pipelines with pre-approval to negotiate terms and conditions of service. To the extent that pipelines, in

³⁰⁰See *Reliant Energy Gas Transmission Company*, 87 FERC ¶ 61,298 (1999) (hourly flexibility service designed to meet needs of gas generators); *Mojave Pipeline Company*, 79 FERC ¶ 61,347 (1997); *Colorado Interstate Gas Company*, 83 FERC ¶ 61,273 (1998) (parking and loan service).

certain circumstances, find that they are unable to file an open access tariff-based service to accommodate particular needs, and that individual negotiation is the only feasible method of providing service to a particular shipper, the pipeline is still permitted under the Commission's regulations to file a non-conforming contract with the Commission.³⁰¹ Such a filing has to be made at least 30 days prior to the proposed effective date,³⁰² which gives other parties and the Commission the opportunity to review all aspects of the non-conforming contract to determine whether the contract is unduly discriminatory or preferential or would negatively affect the service provided to other shippers.

The determination not to move forward at this juncture with pre-approved negotiated terms and conditions of service raises the question of how the Commission will differentiate between negotiated rates, permissible under the Commission's negotiated rates policy,³⁰³ and negotiated terms and conditions of service. While formulating a generic definition of rate applicable to all potential situations is not possible, the Commission generally considers negotiated terms and conditions to be related to operational conditions of transportation service. A negotiated rate would not include conditions or activities related to the transportation of gas on the pipeline, such as scheduling, imbalances, or operational obligations, such as OFOs. By contrast,

³⁰¹18 CFR 154.1(d).

³⁰²18 CFR 154.207.

³⁰³Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), 74 FERC 61,076 (1996).

negotiated rate agreements can include the price, the term of service, the receipt and delivery points, and the quantity.

VI. REORGANIZATION OF PART 284 REGULATIONS

The Commission is reorganizing certain portions of its Part 284 regulations to better reflect the nature of services in the short-term market and to consolidate its Part 284 reporting and filing requirements in a single section. Aside from the regulatory revisions discussed in the body of the preamble, the Commission is not making substantive changes to the regulations, but is making changes to conform its regulations with the new organizational structure.

Because capacity release has become an integral part of the short-term market, the Commission is moving its capacity release regulations from subpart H of Part 284 to the same location in its regulations as pipeline firm and interruptible service (newly designated § 284.7 (firm service), § 284.8 (release of firm service), and § 284.9 (interruptible service)).³⁰⁴

In addition, reporting and filing requirements for pipeline services under Part 284 are presently scattered throughout Part 284. For example, the Index of Customers and storage reports are presently located in subpart B, § 284.106, which deals with interstate pipelines performing transportation service under the Natural Gas Policy Act (NGPA).

³⁰⁴To eliminate redundancy between sections 284.7 dealing with pipeline firm service and section 284.9 dealing with pipeline interruptible service, section 284.9 is being revised to cross-reference the sections of section 284.7 that are applicable to both sections.

But these regulations are then applied to interstate pipelines performing open access services in subpart G, § 284.223. Other reporting requirements are located throughout various substantive provisions of Part 284.³⁰⁵ The Commission is collecting these requirements into new § 284.13 applicable to interstate pipelines transporting gas under Subpart B (transportation under section 311 of the NGPA) and Subpart G (open access transportation under the NGA). Reporting requirements specific to Subpart B pipelines (by-pass reports) remain in Subpart B.

Commenters did not object to the reorganization. Dynegy contends the Commission should not be proposing a requirement for pipelines to file the semi-annual storage report in section 284.14(e) which discloses shippers' names. But the semi-annual storage report is not a new requirement. Pipelines were required to provide this information under existing section 284.102 (b), and the Commission finds no basis for removing a currently applicable requirement. The storage report, however, is being revised to eliminate section (6) requiring pipelines to file the related docket numbers in which the pipeline reported storage related injections and withdrawals. This information is no longer relevant since, after Order No. 636, pipelines are no longer required to file the ST reports on which the injection and withdrawal information was included.

The following is the new outline for subpart A of Part 284.

³⁰⁵ See, e.g., 18 CFR 284.8(b)(3) and 284.9(b)(3) (requirements to provide information on available capacity), 284.7(c)(6) (discount reports), 284.12 (filing of capacity).

- 284.1 Definitions.
- 284.2 Refunds and interest.
- 284.3 Jurisdiction under the Natural Gas Act.
- 284.4 Reporting.
- 284.5 Further terms and conditions.
- 284.6 Rate interpretations.
- 284.7 Firm transportation service.
- 284.8 Release of firm transportation service
- 284.9 Interruptible transportation service.
- 284.10 Rates.
- 284.11 Environmental compliance.
- 284.12 Standards for pipeline business operations and communications
- 284.13 Reporting requirements for interstate pipelines.

VII. IMPLEMENTATION SCHEDULE

The regulatory changes made in this rule are being implemented at different times and will require the pipelines to make tariff or pro forma tariff filings. The following summarizes the implementation and compliance schedule for the rule.

1. Maximum Ceiling Rate for Capacity Release Transactions. The regulation removing the maximum ceiling rate for short-term capacity release transactions will become effective as of the date of this rule. Pipelines must file within 180 days to remove inconsistent tariff provisions and can incorporate this filing into any other tariff filing made by the pipeline within the 180 day period.

2. Scheduling, Segmentation, Penalty Regulations. To comply with the regulations governing scheduling of capacity release transactions, segmentation, and penalties, pipelines are required to make pro forma tariff filings by May 1, 2000. Thirty days will be provided for the filing of comments and protests. After review of the filing

and comments or protests, the Commission will determine whether further procedures are needed and the effective date for any tariff changes.

3. Reporting Requirements. Pipelines must comply with the reporting requirements by September 1, 2000, in accordance with the procedures discussed earlier.

4. ROFR. The regulatory change to the ROFR becomes effective on the date this rule becomes effective. Pipelines that have different provisions in their tariffs can, but are not required to, file to modify their existing tariffs to accord with the regulatory changes made in this rule. Until such filing is accepted, the pipeline's current tariff provisions will continue to apply.

VIII. INFORMATION COLLECTION STATEMENT

The Office of Management and Budget's (OMB) regulations in 5 CFR 1320.11 require that it approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB shall assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Final Rule shall not be penalized for failing to respond to these collections of information unless the collections of information display valid OMB control numbers.

The collections of information related to the subject of this Final Rule fall under FERC-545, "Gas Pipeline Rates: Rate Change (Non-Formal)" (OMB Control No. 1902-0154); FERC-549 "Gas Pipeline Rates: Natural Gas Policy Act; Title III Transactions" (OMB Control No. 1902-0086); FERC-549B "Capacity Information" (OMB Control No.

1902-0169) and FERC-592 "Marketing Affiliates of Interstate Pipelines" (OMB Control No. 1902-0157).

Under this Final Rule, the overall reporting requirements will be increased based on the addition of certain information, namely the receipt and delivery point data in transactional reports and the Index of Customers plus organizational and personnel information on affiliates. However, there will also be a reduction in the amount of periodic reporting to the Commission and the elimination of the requirement to submit discount reports. On the whole, the Commission estimates that the revised reporting schedule will increase the existing reporting burden by a total of 77,847 hours. The bulk of the increase will not be extensive, relying not on collecting the data but in creating new formats for displaying the information on the pipelines' Internet websites.

Public Reporting Burden:

The burden estimates for complying with this proposed rule are as follows:
(*reductions in parenthesis*)

Data Collection	No. Of Respondents	No. of Responses per Respondent	Estimated Burden Hours per Response	Total Annual Hours
FERC-545	100	1.4	115.2	16,128
FERC-549	78	1	(2.7)	(211)
FERC-549B	100	333.9	183.86	61,391
FERC-592	74	1	7.28	539
TOTAL				77,847

The total annual hours for collection (including recordkeeping) is estimated to be 77,847.

Information Collection Costs: The average annualized cost for all respondents is projected to be the following (savings in parenthesis):

	FERC-545	FERC-549	FERC-549B	FERC-592	Totals
Annualized Capital/Startup Costs	643,529	0.00	1,455,662	0.00	2,099,191
Annualized Costs (Operations & Maintenance)	221,374	(11,315)	1,836,578	28,905	2,075,542
Total Annualized Costs	864,903	(11,315)	3,292,240	28,905	4,174,733

Title: FERC-545, 549, 549B and 592.

Action: Proposed Data Collections.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: On occasion.

Necessity of Information: The proposed rule seeks to establish reporting requirements that will provide information needed for the market to operate more efficiently and for shippers and the Commission to effectively monitor transactions for undue discrimination and the exercise of market power. Information on market structure enables the Commission to know who hold or controls capacity on each portion of the pipeline system, so the potential sources of capacity can be determined. The information required

in the current regulations is not as complete as that required in this rule and provides inconsistent information for competing types of capacity, both in terms of the content of the information and the formats used to report the information.

Internal Review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements. The internal review involves among other things, an examination of the necessity and adequacy of the information required, and the design, cost, reliability, and redundancy of the information. The data collected will enable the industry and the Commission to monitor the structure, conduct, and performance of the gas industry. This information will enable the Commission to monitor changes in the marketplace that affect Commission regulatory policy and help in identifying, and responding to, markets where light-handed regulation may be appropriate as well as markets in which constraints on competition still exist. These requirements conform to the Commission's plan for efficient information collection, communication, and management within the natural gas pipeline industry.

One-hundred-forty-three comments were filed in response to the NOPR. While the Commission did not receive any comments concerning its estimates for reporting burden, seven entities commented on the additional reporting burden placed upon them by the changes made in this rule. The Commission has addressed their concerns within the preamble of the rule in the appropriate section. Further, as required under OMB regulations, the Commission submitted the NOPR to OMB for review. OMB noted

acceptance of the NOPR, but took no action on the NOPR. In its response, OMB stated that the Commission should submit its information requests when it takes final action.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, [Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202)208-1415, fax: (202)273-0873, E-mail: mike.miller@ferc.fed.us] or the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202)395-3087, fax: (202)395-7285.

IX. ENVIRONMENTAL ANALYSIS

The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.³⁰⁶ The Commission has categorically excluded certain actions from these requirements as not having a significant effect on the human environment.³⁰⁷ The actions taken here fall within categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, for information gathering, analysis, and dissemination, and for sales, exchange, and

³⁰⁶Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

³⁰⁷18 CFR 380.4.

transportation of natural gas that requires no construction of facilities.³⁰⁸ Therefore, an environmental assessment is unnecessary and has not been prepared in this rulemaking.

X. REGULATORY FLEXIBILITY ACT CERTIFICATION

The Regulatory Flexibility Act of 1980 (RFA)³⁰⁹ generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The regulations adopted here impose requirements on interstate pipelines, which generally are not small businesses. Accordingly, pursuant to section 605(b) of the RFA, the Commission certifies that the regulations adopted herein will not have a significant adverse impact on a substantial number of small entities.

XI. DOCUMENT AVAILABILITY

In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.fed.us>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

³⁰⁸See 18 CFR 380.4(a)(2)(ii), 380.4(a)(5), 380.4(a)(27).

³⁰⁹5 U.S.C. 601-612.

From FERC's Home Page on the Internet, this information is available in both the Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS).

- - CIPS provides access to the texts of formal documents issued by the Commission since November 14, 1994.

- - CIPS can be accessed using the CIPS link or the Energy Information Online. The full text of this document will be available on CIPS in ASCII or WordPerfect 8.0 format for viewing, printing, and/or downloading.

- - RIMS contains images of documents submitted to and issued by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed from FERC's Home Page using the RIMS link or the Energy Information Online icon. Descriptions of documents back to November 16, 1981, are also available from RIMS-on-the-Web; requests for copies of these and older documents should be submitted to the Public Reference Room.

User assistance is available for RIMS, CIPS, and the Website during normal business hours from the Help line at 202-208-2222 (E-Mail to WebMaster@ferc.fed.us) or the Public Reference Room at 202-208-1371 (E-Mail to public.referenceroom@ferc.fed.us).

During normal business hours, documents can also be viewed and/or printed in FERC's Public Reference Room, where RIMS, CIPS, and the FERC Website are available. User assistance is also available.

XII. EFFECTIVE DATE

These regulations are effective [insert date 30 days after publication in the FEDERAL REGISTER], with the exception of the removal of paragraph (c)(6) of redesignated section 284.10, which will be effective on September 1, 2000. The

Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects

18 CFR Part 154

Natural gas; Pipelines; Reporting and recordkeeping requirements.

18 CFR Part 161

Natural gas; Reporting and recordkeeping requirements.

18 CFR Part 250

Natural gas; Reporting and recordkeeping requirements.

18 CFR Part 284

Continental shelf; Incorporation by reference; Natural gas; Reporting and recordkeeping requirements.

By the Commission. Commissioner Hébert concurred with a separate statement attached.

(S E A L)

David P. Boergers,
Secretary.

In consideration of the foregoing, the Commission amends Part 154, Part 161, Part 250, and Part 284, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 154 -- RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 154 continues to read as follows:

Authority: 15 U.S.C. 717-717w; 31 U.S.C. 9701; 42 U.S.C. 7102-7352.

2. In § 154.111(a), remove the words "§ 284.106 or § 284.223" and add, in their place, the word "§ 284.13(c)".

PART 161 -- STANDARDS OF CONDUCT FOR INTERSTATE PIPELINES WITH
MARKETING AFFILIATES

3. The authority citation for Part 161 continues to read as follows:

Authority: 15 U.S.C. 717-717w, 3301-3432; 42 U.S.C. 7101-7352.

4. Section 161.3 is amended as follows:

a. In paragraph (h)(2), revise all references to "§ 284.10(a)" to read "§ 284.12" wherever it appears, revise the phrase "Electronic Bulletin Board operated pursuant to" and add in its place the phrase "Internet web site operated complying with" wherever it appears, revise the phrase "EBB" and add in its place the phrase "Internet web site" wherever it appears, and revise the phrase "Electronic Bulletin Board" and add in its place the phrase "Internet web site" wherever it appears; and

b. Revise paragraph (l) to read as follows:

§ 161.3 Standards of conduct

* * * * *

(l)(1) A pipeline must post the names and addresses of its marketing affiliates on its web site on the public Internet and update the information within three business days of any change. A pipeline must also state the date the information was last updated.

Postings must conform with the requirements of § 284.12 of this chapter.

(2) A pipeline must post the following information on its Internet web site complying with § 284.12 of this chapter and update the information within three business days of any change, posting the date on which the information was updated:

(i) A complete list the names of operating personnel and facilities shared by the pipeline and its marketing affiliates; and

(ii) Comprehensive organizational charts showing:

(A) The organizational structure of the parent corporation with the relative position in the corporate structure of the pipeline and all marketing affiliates;

(B) For the pipeline, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transportation or gas sales, and the name of supervisory employees who manage non-clerical employees involved in transportation or gas sales.

(C) For all employees shared by the pipeline and a marketing affiliate, the business unit within the marketing affiliate organizational structure in which the employee is located, the employee's name, job title and job description in the marketing affiliate, and the employees position within the chain of command of the marketing affiliate.

PART 250 -- FORMS

5. The authority citation for Part 250 continues to read as follows:

Authority: 15 U.S.C. 717-717w, 3301-3432; 42 U.S.C. 7101-7352.

6. Section 250.16 is amended as follows:

a. Paragraph (b)(1) is removed, paragraph (b)(2) is redesignated as (b)(1), and a new paragraph (b)(2) is added and reserved.

b. Revise all references to "284.10(a)" to read "284.12" wherever it appears, revise the phrase "Electronic Bulletin Board" and add, in its place, the phrase "Internet Web site" wherever it appears, and revise the phrase "Electronic Bulletin Boards" and add, in its place, the phrase "Internet Web sites" wherever it appears.

PART 284 -- CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS
UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED
AUTHORITIES

7. The authority citation for Part 284 continues to read as follows:

Authority: 15 U.S.C. 717-717w, 3301-3432; 42 U.S.C. 7101-7532; 43 U.S.C.
1331-1356.

8. Part 284 is amended by removing § 284.12.

9. Part 284 is amended by redesignating the sections as set forth in the following
redesignation table:

Old Section	New Section
284.7	284.10
284.8	284.7
284.10	284.12
284.243	284.8

10. In newly redesignated § 284.7, paragraph (b)(3) is removed and paragraph (b)(4) is redesignated as paragraph (b)(3), paragraphs (d) and (e) are redesignated as paragraphs (e) and (f) respectively, and new paragraph (d) is added to read as follows:

§ 284.7 Firm transportation service.

* * * * *

(d) *Segmentation.* An interstate pipeline that offers transportation service under subpart B or G of this part must permit a shipper to make use of the firm capacity for which it has contracted by segmenting that capacity into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible.

* * * * *

11. Newly redesignated § 284.8 is amended as follows:

a. In paragraph (d), revise all references to "Electronic Bulletin Board" to read "Internet web site" wherever it appears; and

b. Paragraph (i) is added to read as follows:

§ 284.8 Release of firm transportation service.

* * * * *

(i) *Waiver of maximum rate ceiling.* Until September 30, 2002, the maximum rate ceiling does not apply to capacity release transactions of less than one year. With respect to releases of 31 days or less under paragraph (h), the requirements of paragraph (h)(2) will apply to all such releases regardless of the rate charged.

12. In § 284.9, paragraphs (c) and (e) are removed, paragraph (d) is redesignated as paragraph (c), and paragraph (b) is revised to read as follows:

§ 284.9 Interruptible transportation service.

* * * * *

(b) The provisions regarding non-discriminatory access, reasonable operational conditions, and limitations contained in § 284.7 (b), (c), and (f) apply to pipelines providing interruptible service under this section.

* * * * *

13. In newly redesignated § 284.10, paragraph (c)(6) is removed.

14. In newly redesignated § 284.12, paragraphs (c)(1)(ii) and (c)(2)(iii) through (v) are added to read as follows:

§ 284.12 Standards for pipeline business operations and communications.

* * * * *

(c) * * *

(1) * * *

(ii) *Capacity release nominations.* Pipelines must permit shippers acquiring released capacity to submit a nomination at the earliest available nomination opportunity after the acquisition of capacity. If the pipeline requires the replacement shipper to enter into a contract, the contract must be issued within one hour after the pipeline has been notified of the release, but the requirement for contracting must not inhibit the ability of

the replacement shipper to submit a nomination at the earliest available nomination opportunity.

(2) * * *

(iii) *Imbalance management.* A pipeline must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. A pipeline also must provide its shippers the opportunity to obtain similar imbalance management services from other providers and shall provide those shippers using other providers access to transportation and other pipeline services without undue discrimination or preference.

(iv) *Operational flow orders.* A pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system. A pipeline must set forth in its tariff clear standards for when such measures will begin and end and must provide timely information that will enable shippers to minimize the adverse impacts of these measures.

(v) *Penalties.* A pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service. Pipelines may not retain net penalty revenues, but must credit them to shippers in a manner to be prescribed in the pipeline's tariff. A pipeline must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.

* * * * *

15. Part 284 is amended by adding § 284.13 to read as follows:

§ 284.13 Reporting requirements for interstate pipelines.

An interstate pipeline that provides transportation service under subparts B or G of this part must comply with the following reporting requirements.

(a) *Cross references.* The pipeline must comply with the requirements in Part 161, Part 250, and Part 260 of this chapter, where applicable.

(b) *Reports on firm and interruptible services.* An interstate pipeline must post the following information on its Internet web site, and provide the information in downloadable file formats, in conformity with § 284.12 of this part, and must maintain access to that information for a period not less than 90 days from the date of posting.

(1) For pipeline firm service and for release transactions under § 284.8 of this part, the pipeline must post, contemporaneously with the execution or revision of a contract for service:

(i) The full legal name of the shipper, and identification number, of the shipper receiving service under the contract, and the full legal name, and identification number, of the releasing shipper if a capacity release is involved or an indication that the pipeline is the seller of transportation capacity;

(ii) The contract number for the shipper receiving service under the contract, and, in addition, for released transactions, the contract number of the releasing shipper's contract;

- (iii) The rate charged under each contract;
 - (iv) The maximum rate, and for capacity release transactions not subject to a maximum rate, the maximum rate that would be applicable to a comparable sale of pipeline services;
 - (v) The duration of the contract;
 - (vi) The receipt and delivery points and zones or segments covered by the contract, including the industry common code for each point, zone, or segment;
 - (vii) The contract quantity or the volumetric quantity under a volumetric release;
 - (viii) Special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract; and
 - (ix) Whether there is an affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper.
- (2) For pipeline interruptible service, the pipeline must post on a daily basis:
- (i) The full legal name, and identification number, of the shipper receiving service;
 - (ii) The rate charged;
 - (iii) The maximum rate;
 - (iv) The receipt and delivery points and zones or segments covered by the contract over which the shipper is entitled to transport gas, including the industry common code for each point, zone, or segment;
 - (v) The quantity of gas the shipper is entitled to transport;

(vi) Special details pertaining to the contract; and

(vii) Whether the shipper is affiliated with the pipeline.

(c) *Index of customers.* (1) On the first business day of each calendar quarter, an interstate pipeline must file with the Commission an index of all its firm transportation and storage customers under contract as of the first day of the calendar quarter that complies with the requirements set forth by the Commission. The Commission will establish the requirements and format for such filing. The index of customers must also be posted on the pipeline's Internet web, in accordance with standards adopted in § 284.12 of this part, and made available from the Internet web site in a downloadable format complying with the specifications established by the Commission. The information posted on the pipeline's Internet web site must be made available until the next quarterly index is posted.

(2) For each shipper receiving firm transportation or storage service, the index must include the information listed below:

(i) The full legal name, and identification number, of the shipper;

(ii) The applicable rate schedule number under which the service is being provided;

(iii) The contract number;

(iv) The effective and expiration dates of the contract;

(v) For transportation service, the maximum daily contract quantity (specify unit of measurement), and for storage service, the maximum storage quantity (specify unit of measurement);

(vi) The receipt and delivery points and the zones or segments covered by the contract in which the capacity is held, including the industry common code for each point, zone, or segment;

(vii) An indication as to whether the contract includes negotiated rates;

(viii) The name of any agent or asset manager managing a shipper's transportation service; and

(ix) Any affiliate relationship between the pipeline and a shipper or between the pipeline and a shipper's asset manager or agent.

(3) The requirements of this section do not apply to contracts which relate solely to the release of capacity under § 284.8, unless the release is permanent.

(4) Pipelines that are not required to comply with the index of customers posting and filing requirements of this section must comply with the index of customer requirements applicable to transportation and sales under Part 157 as set forth under § 154.111(b) and (c) of this chapter.

(5) The requirements for the electronic index can be obtained from the Federal Energy Regulatory Commission, Division of Information Services, Public Reference and Files Maintenance Branch, Washington, DC 20426.

(d) *Available capacity.* (1) An interstate pipeline must provide on its Internet web site and in downloadable file formats, in conformity with § 284.12 of this part, equal and timely access to information relevant to the availability of all transportation services, including, but not limited to, the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, whether the capacity is available directly from the pipeline or through capacity release, the total design capacity of each point or segment on the system, the amount scheduled at each point or segment on a daily basis, and all planned and actual service outages or reductions in service capacity.

(2) An interstate pipeline must make an annual filing by March 1 of each year showing the estimated peak day capacity of the pipeline's system, and the estimated storage capacity and maximum daily delivery capability of storage facilities under reasonably representative operating assumptions and the respective assignments of that capacity to the various firm services provided by the pipeline.

(e) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline must file with the Commission a report of storage activity. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(2) The rate schedule under which the storage injection or withdrawal service was performed;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period; and

(5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period.

16. In § 284.102, paragraph (c) is revised to read as follows:

§ 284.102 Transportation by interstate pipelines.

* * * * *

(c) An interstate pipeline that engages in transportation arrangements under this subpart must file reports in accordance with § 284.13 and § 284.106 of this chapter.

* * * * *

17. In § 284.106, paragraphs (b) through (c) are removed, the paragraph (a) designation and the associated heading are removed, and the section heading is revised to read as follows:

§ 284.106 Notice of bypass.

* * * * *

18. In § 284.221, paragraph (d)(2)(ii) is revised to read as follows:

§ 284.221 General rule; transportation by interstate pipelines on behalf of others.

* * * *

(d) * * *

(2) * * *

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the applicable maximum rate under § 284.10, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching the terms of any such offer. To be eligible to exercise this right of first refusal, the firm shipper's contract must be for service for twelve consecutive months or more at the applicable maximum rate for that service.

* * * *

19. In § 284.223, the paragraph (a) designation is removed and paragraph (b) is removed.

20. §§ 284.10, 284.123, 284.221, 284.261, 284.263, 284.266, and 284.286 [Amended]

In addition to the amendments set forth above, in 18 CFR part 284, the following nomenclature changes are made:

a. In Subparts B through L, revise all references to "§ 284.7" to read "§ 284.10" wherever it appears.

b. In Subparts B through L, revise all references to "§§ 284.8-284.13" to read "§§ 284.7-284.9 and §§ 284.11-284.13" wherever it appears.

c. In newly redesignated §§ 284.10(c)(1) and (c)(2), revise all references to "§ 284.8(d)" to read "§ 284.7(e)".

d. In § 284.123 (b)(1), revise all references to "§§ 284.8" to read "§§ 284.7".

e. In § 284.286(b), revise all references to "§§ 284.8(b)(2)" to read "§§ 284.7(b)(2)".

f. In section 284.286(c), revise all references to "§§ 161.3(c), (e), (f), (g), and (h)" to read "§§ 161.3(c), (e), (f), (g), (h), and (l)".

Note: The following Appendix will not appear in the Code of Federal Regulations

APPENDIX

Comments Filed in Docket Nos.
RM98-10-000 & RM98-12-000³¹⁰

Commenter	Abbreviation	Docket No.
AEC Marketing (USA) Inc.	AEC	RM98-10-000
Alabama Gas Corporation	Alagasco	RM98-10-000
Allenergy Marketing Company, LLC, Enron Energy Services, Inc., Enserch Energy Services, Inc. and Statoil Energy, Inc.	Allenergy	RM98-10-000 & RM98-12-000 (joint filing)
Alliance Pipeline L.P.	Alliance	RM98-10-000 & RM98-12-000 (joint filing)
AlliedSignal Inc.	AlliedSignal I	RM98-10-000
AlliedSignal Inc.	AlliedSignal II	RM98-12-000
Altra Energy Technologies, Inc.	Altra	RM98-10-000
American Forest & Paper Association	AF&PA I	RM98-10-000
American Forest & Paper Association	AF&PA II	RM98-12-000
American Gas Association	AGA I	RM98-10-000
American Gas Association	AGA II	RM98-12-000
American Public Gas Association	APGA	RM98-10-000 & RM98-12-000 (joint filing)
Amoco Energy Trading Corporation and Amoco Production Company	Amoco I	RM98-10-000

³¹⁰Parties filing a single document in response to the NOPR in Docket No. RM98-10-000 and the NOI in Docket No. RM98-12-000 are denominated as a joint filing.

Commenter	Abbreviation	Docket No.
Amoco Energy Trading Corporation, Amoco Production Company, Burlington Resources Oil & Gas Co., and Marathon Oil Company	Amoco II	RM98-12-000
Arkansas Gas Consumers	Arkansas Gas Consumers	RM98-10-000
Arkansas Public Service Commission	Arkansas PSC	RM98-10-000 & RM98-12-000 (joint filing)
Atlanta Gas Light Company	AGLC I	RM98-10-000
Atlanta Gas Light Company	AGLC II	RM98-12-000
Baltimore Gas and Electric Company	BG&E I	RM98-10-000
Baltimore Gas and Electric Company	BG&E II	RM98-12-000
Brooklyn Union Gas Company and Keyspan Gas East Corporation	Brooklyn Union	RM98-10-000 & RM98-12-000 (joint filing)
Canadian Association of Petroleum Producers and Alberta Department of Energy	CAPP/ADOE	RM98-12-000
City of Hamilton, Ohio	City of Hamilton, Ohio	RM98-10-000
CMS Panhandle Pipe Line Companies	CMS Panhandle	RM98-10-000 & RM98-12-000 (joint filing)
Coastal Companies	Coastal I	RM98-10-000
Coastal Companies	Coastal II	RM98-12-000
Colorado Springs Utilities	Colorado Springs I	RM98-10-000
Colorado Springs Utilities	Colorado Springs II	RM98-12-000
Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., and Columbia Gas of Virginia, Inc.	Columbia LDCs	RM98-10-000 & RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company	Columbia	RM98-10-000 & RM98-12-000 (joint filing)
Conoco Inc.	Conoco	RM98-10-000 & RM98-12-000 (joint filing)
Consolidated Edison Company of New York, Inc.	ConEd	RM98-10-000 & RM98-12-000 (joint filing)
Consolidated Natural Gas Company	Consolidated Natural I	RM98-10-000
Consolidated Natural Gas Company	Consolidated Natural II	RM98-12-000
Consumers Energy Company	Consumers Co.	RM98-12-000
Cove Point LNG Limited Partnership	Cove Point	RM98-10-000
Delta Natural Gas Company	Delta	RM98-10-000
Duke Energy Trading and Marketing, LLC	Duke Energy	RM98-10-000 & RM98-12-000 (joint filing)
Dynegy Inc.	Dynegy	RM98-10-000 & RM98-12-000 (joint filing)
Edison Electric Institute	EEI	RM98-10-000 & RM98-12-000 (joint filing)
El Paso Energy Corporation Interstate Pipelines	El Paso Energy	RM98-10-000 & RM98-12-000 (joint filing)
El Paso Natural Gas Company	El Paso Natural	RM98-10-000 & RM98-12-000 (joint filing)
Enron Capital & Trade Corporation	Enron Capital	RM98-10-000 & RM98-12-000 (joint filing)
Enron Interstate Pipelines	Enron Pipelines	RM98-10-000 & RM98-12-000 (joint filing)
Entergy Services, Inc.	Entergy	RM98-10-000 & RM98-12-000 (joint filing)
Exxon Corporation	Exxon	RM98-10-000 & RM98-12-000 (joint filing)
Fertilizer Institute	Fertilizer Institute	RM98-10-000 & RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
Florida Cities	Florida Cities	RM98-10-000 & RM98-12-000 (joint filing)
Florida Department of Management Services	Florida DMS	RM98-10-000
Foothills Pipe Lines Ltd.	Foothills	RM98-10-000 & RM98-12-000 (joint filing)
FPL Group, Inc.	FPL	RM98-10-000 & RM98-12-000 (joint filing)
Illinois Commerce Commission	Illinois Commerce Comm.	RM98-10-000 & RM98-12-000 (joint filing)
Illinois Municipal Gas Agency	IMGA	RM98-10-000 & RM98-12-000 (joint filing)
IMD Storage, Transportation and Asset Management Company, LLC	IMD	RM98-10-000 & RM98-12-000 (joint filing)
Independent Oil and Gas Association of Pennsylvania	IOGA-PA	RM98-10-000 and RM98-12-000 (joint filing)
Independent Oil and Gas Association of West Virginia	IOGA-WV	RM98-10-000 & RM98-12-000 (joint filing)
Independent Oil and Gas Association of New York	IOGA-NY	RM98-10-000 & RM98-12-000 (joint filing)
Independent Oil and Gas Association of Kentucky	IOGA-KY	
Independent Petroleum Association of America	IPAA	RM98-10-000 & RM98-12-000 (joint filing)
Indicated Shippers	Indicated Shippers	RM98-10-000 & RM98-12-000 (joint filing)
Interstate Natural Gas Association of America	INGAA	RM98-10-000 & RM98-12-000 (joint filing)
Iowa Utilities Board	Iowa	RM98-10-000 & RM98-12-000 (joint filing)
John A. Bell, Jr.	John A. Bell, Jr.	RM98-10-000
K N Pipelines, Inc.	K N	RM98-10-000 & RM98-12-000 (joint filing)
Koch Gateway Pipeline Company	Koch I	RM98-10-000

Commenter	Abbreviation	Docket No.
Koch Gateway Pipeline Company	Koch II	RM98-12-000
Louisville Gas and Electric Company (Jan. & April)	Louisville	RM98-10-000 & RM98-12-000 (joint filing)
Market Hub Partners, L.P.	Market Hub Partners	RM98-10-000 & RM98-12-000 (joint filing)
Michigan Consolidated Gas Company	MichCon	RM98-10-000 & RM98-12-000 (joint filing)
Midland Cogeneration Venture Limited Partnership	Midland	RM98-10-000 & RM98-12-000 (joint filing)
Millennium Pipeline Company, L.P.	Millennium	RM98-10-000 & RM98-12-000 (joint filing)
Minnesota Department of Public Service	Minnesota	RM98-10-000 & RM98-12-000 (joint filing)
Mississippi Independent	Mississippi Independent	RM98-10-000
Mississippi Valley Gas Company, Willmut Gas Company, City of Vicksburg, Mobile Gas Service Corporation, Wheeler Basin Natural Gas Company, Clarke-Mobile Counties Gas District	Mississippi Valley	RM98-10-000 & RM98-12-000 (joint filing)
National Association of State Utility Consumer Advocates	NASUCA	RM98-10-000 & RM98-12-000 (joint filing)
National Association of Regulatory Utility Commissioners	NARUC	RM98-10-000 & RM98-12-000 (joint filing)
National Energy Marketers Association	NEMA	RM98-10-000 & RM98-12-000 (joint filing)
National Fuel Gas Distribution	National Fuel Distribution	RM98-10-000 & RM98-12-000 (joint filing)
National Fuel Gas Supply Corporation	National Fuel	RM98-10-000
Natural Gas Supply Association	NGSA	RM98-10-000 & RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
New England Gas Distributors	New England	RM98-10-000 & RM98-12-000 (joint filing)
New York Mercantile Exchange	NYMEX	RM98-10-000
Nicor Gas	Nicor	RM98-10-000
Nisource, Inc.	Nisource	RM98-10-000
North Carolina Natural Gas Corporation	NC Natural Gas	RM98-10-000 & RM98-12-000 (joint filing)
Northern Municipal Distributors Group and The Midwest Region Gas Task Force Association	Northern Municipal I	RM98-10-000
Northern Municipal Distributors Group and The Midwest Region Gas Task Force Association	Northern Municipal II	RM98-12-000
Northwest Industrial Gas Users	NWIGU	RM98-10-000 & RM98-12-000 (joint filing)
Northwest Natural Gas Company	NW Natural	RM98-12-000
Ohio Oil & Gas Association	OOGA	RM98-10-000 & RM98-12-000 (joint filing)
Oklahoma Independent Petroleum Association	OIPA	RM98-10-000 & RM98-12-000 (joint filing)
Paiute Pipeline Company	Paiute	RM98-10-000
PanCanadian Petroleum Limited and PanCanadian Energy Services, Inc.	PanCanadian	RM98-10-000 & RM98-12-000 (joint filing)
Peco Energy Company	Peco	RM98-12-000
Pennsylvania Office of Consumer Advocate and the Ohio Consumers' Counsel	Penn./Ohio Advocate	RM98-10-000 & RM98-12-000 (joint filing)
Pennsylvania Oil & Gas Association	Penn. Oil & Gas Assoc.	RM98-10-000 & RM98-12-000 (joint filing)
Pennsylvania Public Utility Commission	Penn. PUC	RM98-10-000 & RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
Peoples Energy Corporation	Peoples Energy I	RM98-10-000
Peoples Energy Corporation	Peoples Energy II	RM98-12-000
Pepco Energy Company	Pepco	RM98-12-000
PG&E Corporation	PG&E	RM98-10-000 and RM98-12-000 (joint filing)
Philadelphia Gas Works	Philadelphia Gas Works	RM98-10-000 & RM98-12-000 (joint filing)
Piedmont Natural Gas Company, Inc. and UGI Utilities, Inc.	Piedmont/UGI	RM98-10-000 & RM98-12-000 (joint filing)
Pipeline Transportation Customer Coalition	P/L Customer Coalition	RM98-10-000 & RM98-12-000 (joint filing)
Portland Natural Gas Transmission System	PNGTS	RM98-10-000
Process Gas Consumers Group -- American Iron and Steel Institute, Georgia Industrial Group, Aluminum Company of America and United States Gypsum Company	Process Gas Consumers I	RM98-10-000
Process Gas Consumers Group -- American Iron and Steel Institute, Georgia Industrial Group, Aluminum Company of America and United States Gypsum Company	Process Gas II Consumers	RM98-12-000
Production Area Rate Design Group	Production Area Group	RM98-10-000 & RM98-12-000 (joint filing)
Proliance Energy, LLC	Proliance	RM98-10-000 & RM98-12-000 (joint filing)
Public Service Commission of the State of New York	PSC of New York I	RM98-10-000
Public Service Commission of the State of New York	PSC of New York II	RM98-12-000
Public Service Commission of the Commonwealth of Kentucky	PSC of Kentucky	RM98-10-000 & RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
Public Service Commission of Wisconsin	PSC of Wisconsin I	RM98-10-000
Public Service Commission of Wisconsin	PSC of Wisconsin II	RM98-12-000
Public Service Electric and Gas Company	PSE&G	RM98-10-000 & RM98-12-000 (joint filing)
Public Utilities Commission of the State of California	CPUC	RM98-10-000 & RM98-12-000 (joint filing)
Public Utilities Commission of Ohio	PUC of Ohio	RM98-10-000
Regulatory Studies Program of the Mercatus Center, George Mason University	Mercatus	RM98-10-000 & RM98-12-000 (joint filing)
Reliant Energy Gas Transmission Company and Mississippi River Transmission Corporation	Reliant	RM98-10-000 & RM98-12-000 (joint filing)
Sempra Energy	Sempra Energy	RM98-10-000 & RM98-12-000 (joint filing)
Shell Energy Services Company, LLC	Shell	RM98-10-000
Sithe Energies, Inc.	Sithe	RM98-10-000 & RM98-12-000 (joint filing)
Southern Company Energy Marketing L.P.	Southern Co. Energy	RM98-10-000
Southern Company Services, Inc.	Southern Co. Services	RM98-10-000 & RM98-12-000 (joint filing)
Southern Natural Gas Company	Southern Natural	RM98-10-000 & RM98-12-000 (joint filing)
Southwest Gas Corporation	Southwest Gas	RM98-10-000 & RM98-12-000 (joint filing)
Tejas Offshore Pipelines, LLC	Tejas I	RM98-10-000
Tejas Offshore Pipelines, LLC	Tejas II	RM98-12-000
Tennessee Valley Authority	TVA	RM98-10-000 and RM98-12-000 (joint filing)

Commenter	Abbreviation	Docket No.
Texas Eastern Transmission Corporation and Algonquin Gas Transmission Company	TETCO/Algonquin	RM98-10-000 & RM98-12-000 (joint filing)
The Customer Coalition	The Customer Coalition	RM98-10-000
The Railroad Commission of Texas	TRRC	RM98-10-000 & RM98-12-000 (joint filing)
TransCanada Gas Services, A Division of TransCanada Energy, LTD	TransCanada	RM98-10-000 & RM98-12-000 (joint filing)
TransCapacity Limited Partnership	TransCapacity	RM98-10-000
UGI Utilities, Inc.	UGI	RM98-10-000 and RM98-12-000 (joint filing)
Vector Pipeline L.P.	Vector	RM98-10-000 & RM98-12-000 (joint filing)
Washington Gas Light Company	WGL I	RM98-10-000
Washington Gas Light Company	WGL II	RM98-12-000
Williams Companies, Inc.	Williams I	RM98-10-000
Williams Companies, Inc.	Williams II	RM98-12-000
Williston Basin Interstate Pipeline Company	Williston Basin	RM98-10-000 & RM98-12-000 (joint filing)
Wisconsin Distribution Group	Wisconsin Distributors	RM98-10-000 & RM98-12-000 (joint filing)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of short-term Natural Gas
Transportation Services

Docket No. RM98-10-000

Regulation of Interstate Natural Gas

Docket No. RM98-12-000

(Issued February 9, 2000)

Hébert, Commissioner, *concurring*

Without question, the steps taken in this rule, with one exception, are a significant victory for pricing flexibility necessary to stride confidently toward a market-based approach for transportation of natural gas instead of retaining elements of price controls.

The removal of the price cap on capacity release transactions provides multiple benefits to the marketplace. Capacity release transactions become a viable alternative to bundled sales of natural gas. The incentive provided by the alternative will result in a more efficient use of existing capacity, storage facilities and peak shaving devices. Revenues resulting from capacity release transactions can materially benefit customers by reducing cost shifting. Peak and off-peak rates should also benefit customers in future rate proceedings through minimizing discounts during off-peak periods.

Through this rule, I believe this Commission will gain a better understanding of the value of pipeline capacity and will provide proper pricing alternatives to the industry. It remains vital to the consumer that market demand for capacity not be ignored, nor unaddressed, in our efforts to ensure a reliable and sufficient infrastructure for the transportation of natural gas. I can only hope this Commission will embrace the need for capacity, specifically the northeast. In light of the concerns vehemently expressed by Secretary Richardson on the rising price of heating oil in the northeast, this Commission must act in a reasonable manner and with the interest of the consumers at heart, wherever they are located. Delay, as well as unnecessary environmental and economic hurdles remain unacceptable.

Further, the two-year waiver period concerning the removal of the price caps on capacity release transactions is also unacceptable. The data provided to me appears clear

and convincing that removal of the price caps is a positive and substantiated step designed to benefit the consumer. The studies, contained in this docket as well as the information gathered by the staff, are more than sufficient to justify a permanent removal of the price caps. I will continue to advocate this position in order to ultimately remove the price caps of capacity release transactions. This Commission needs to move toward price reforms, not price controls.

Therefore, I respectfully concur.

Commissioner Curt L. Hébert, Jr.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C.

In the Matter of:

Regulation of Short-Term Natural Gas
Transportation Services, and Regulation
of Interstate Natural Gas Transportation
Services

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Docket No. RM98-10-012

**MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF
PIEDMONT NATURAL GAS COMPANY, INC. TO THE REQUEST FOR
CLARIFICATION AND REHEARING OF TEXAS EASTERN TRANSMISSION,
LP,
ALGONQUIN GAS TRANSMISSION COMPANY, AND
EAST TENNESSEE NATURAL GAS COMPANY**

Piedmont Natural Gas Company, Inc. (Piedmont), through counsel and pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.212 and 385.213, hereby moves for leave to answer and submits the following answer to the *Request for Clarification and Rehearing of Texas Eastern Transmission, LP, Algonquin Gas Transmission Company, and East Tennessee Natural Gas Company* ("Rehearing Request") in this proceeding by which these parties challenge the Commission's October 31, 2002 *Order on Remand* in this proceeding.¹

MOTION FOR LEAVE TO FILE ANSWER

Piedmont requests waiver of the applicability of Rule 213(a)(2) to permit the filing of this Answer to the rehearing request of Texas Eastern Transmission, Algonquin Gas Transmission Company, and East Tennessee

¹Regulation of Short-Term Natural Gas Transportation Services and Regulations of Interstate Natural Gas Transportation Services, *Order on Remand*, 101 FERC ¶ 61,127 (October 31, 2002).

Natural Gas Company (collectively hereinafter referred to as “Texas Eastern”). Piedmont recognizes that the Commission’s rules do not permit answers to requests for rehearing; however, Piedmont respectfully requests leave to file such an answer in this proceeding. In conjunction with this request, Piedmont notes that the Commission has accepted similar responsive pleadings for filings in the past where such pleadings help to form a more complete record upon which to rule and submits that acceptance of Piedmont’s answer in this proceeding would assist the Commission in its analysis of Texas Eastern’s Rehearing Request.² In support of this request, Piedmont also notes that Texas Eastern’s Rehearing Requests contains numerous misstatements of fact and mischaracterizations of the Commission’s policies and seeks a reversal of both the Commission’s policy permitting simultaneous forwardhaul/backhaul transactions to a point as well as a number of the basic tenets underlying both Order No. 636 and Order No. 637.

ANSWER

In its Rehearing Request, Texas Eastern asserts a legion of errors with the Commission’s Order on Remand relating to the Commission’s confirmation of its policy to require interstate pipelines to allow, where operationally feasible, concurrent forwardhaul and backhaul transactions to the same physical delivery point where the cumulative volumes delivered as a result of these transactions exceed the Total Contract Quantity (“TCQ”) of the

²See e.g. *K N Interstate Gas Transmission Company*, 74 FERC ¶ 61,020 (1996); *East Tennessee Natural Gas Company*, 72 FERC ¶ 61,215 (1995).

underlying firm capacity contract (“FH-BH transactions”).³ Texas Eastern’s claims of error are interwoven and repeated *seriatim* throughout Texas Eastern’s pleading but the bulk of the claims can be broken down into a few basic contentions. These are that: (1) the Commission erred by concluding that it had not modified contracts in authorizing FH-BH transactions and by failing to meet its statutory burden to support its decision; (2) the Commission erred by unilaterally changing the certificate authority of interstate pipelines; (3) the Commission erred by doubling the service obligations of interstate pipelines and by requiring them to “give away” service for free; and (4) the Commission erred by concluding that its policy would provide benefits to shippers and the markets for interstate capacity.⁴ None of these assertions of error are well-founded. To the contrary, and as is discussed below, they are based almost entirely upon fundamental misconceptions regarding the nature of the FH-BH

³It is something of a challenge to state all of the qualifying conditions to the types of transactions contemplated by the Commission’s policy on forwardhaul/backhaul to a point in one sentence. To be clear, however, the transactions to which the Commission’s policy applies involve a forwardhaul use of primary (or secondary) capacity rights and a concurrent secondary delivery of backhaul volumes to the same point, all completely within zones for which the underlying shipper pays reservation charges and where the volumes delivered do not exceed the underlying contract TCQ within any segment on the mainline segments through which the volumes are transported. Texas Eastern fails to recognize several of these characteristics in its pleading.

⁴Texas Eastern also makes substantial reference to its LUQ mechanism in its rehearing request, although it is clear that the Commission’s Order on Remand does not address that mechanism. That mechanism is pending rehearing in another docket and has no place in this proceeding. As an aside, that mechanism, which has been rejected by FERC on more than one occasion, is plainly and unequivocally contrary to the Commission’s segmentation policies established in Order No. 636 because it seeks to limit total aggregate deliveries of most types of segmented capacity transactions to a shipper’s TCQ.

transactions and/or attacks (collateral and otherwise) on the Commission's well-established segmentation and flexible secondary receipt and delivery policies established in Order No. 636 and refined in Order No. 637.

I. TEXAS EASTERN'S ARGUMENTS DEMONSTRATE A FUNDAMENTAL MISCONCEPTION OF THE NATURE OF THE FH-BH TRANSACTIONS GOVERNED BY THE COMMISSION'S POLICY AND THE REGULATORY CONTEXT IN WHICH THE COMMISSION'S FH-BH TRANSACTION POLICY ARISES.

In its Rehearing Request arguments, Texas Eastern fails to recognize a number of critical aspects of the FH-BH transactions subject to the Commission's policy and further fails to recognize the consistency of the Commission's decision in its *Order on Remand* with the Commission's longstanding policies permitting segmentation and secondary receipt and delivery flexibility. As a result of this failure, Texas Eastern has essentially created a context for its arguments which does not exist in reality. As such, its arguments are unworthy of serious consideration because they are premised upon false assumptions or misperceived effects that are not reflective of the reality in which these FH-BH transactions occur.

Perhaps the most significant failure by Texas Eastern in this regard is its inability (or unwillingness) to recognize the critical distinction between the attributes of primary firm and secondary capacity. This inability is readily evident from a number of arguments raised by Texas Eastern, including those asserting that the Commission has erred by requiring a "doubling" of shipper's capacity rights and that the Commission has unilaterally changed pipeline certificate levels.⁵ The distinction between primary firm and secondary

⁵These discrete issues are discussed *infra*.

capacity rights is critical to an understanding of the basis of the Commission's FH-BH transaction policy, however, and Texas Eastern's failure to recognize this distinction renders most of its arguments meaningless.

As the Commission is well aware, primary firm transportation capacity is the most ubiquitous and important service provided by interstate pipelines. It is, in essence, the original and core business of interstate pipelines. Rights to this service are established by tariff and by service contracts between pipelines and their customers. The tariffs governing primary firm transportation capacity spell out the essential nature of this service as the highest priority uninterruptible transportation capacity offered by interstate pipelines. Pipeline tariffs also reflect a number of extraneous rights, for Part 284 service, associated with primary firm transportation capacity that are the result of prior Commission policy decisions. These include the right to release such capacity to replacement shippers, the right to segment such capacity and in doing so effect total deliveries in excess of a shippers TCQ, and the right to utilize alternative secondary receipt and delivery points other than those identified in the shipper's service contract. Primary firm transportation service also forms the economic backbone for all pipeline services under the Straight Fixed Variable rate design methodology because on every interstate pipeline of which Piedmont is aware, the vast majority of a pipeline's fixed costs and margin are recovered through the monthly reservation charges assessed to the subscribers of this service. Service contracts between pipelines and their primary firm transportation capacity customers typically supplement the associated tariffs and create the basic contractual infrastructure of the service

arrangement by specifying, at a minimum, the amount of daily capacity subscribed, the term of the agreement, and primary receipt and delivery point designations.

Secondary capacity transactions, in contrast to primary firm transportation transactions, possess none of the same characteristics. They are interruptible in nature and subject to the availability of both mainline and delivery point capacity. They possess neither the priority nor inherent attributes of primary firm capacity. Most importantly, they arise under previously approved Commission Policies, specifically approved in Order No. 636, and are reflected in the tariffs (but not the service agreements) of interstate pipelines. In fact, secondary transactions are nothing more than lower priority receipt and delivery flexibility granted holders of firm transportation capacity by the Commission in recognition of the fact that such capacity holders pay zone wide reservation charges in connection with the underlying firm capacity. The significant distinction between these two types of interstate transportation capacity transactions appears to be largely lost on Texas Eastern in its rehearing request as it clearly and repeatedly discusses these two types of capacity transactions as if they were equivalent.

The same failure to distinguish differences between the two types of service that collectively make up FH-BH transactions is also evident in Texas Eastern's failure to recognize the difference between the right of a primary firm capacity holder to segment mainline capacity into numerous transportation transactions (on both a primary and secondary basis) so long as its TCQ is not exceeded within any such segment and the correlative but different right to

withdraw or inject volumes through receipt and delivery meters associated with those segments. Texas Eastern assumes that these rights are identical but in light of the Commission's established segmentation and secondary delivery policies, that cannot be the case. For example, the Commission's longstanding policies allowing a primary firm shipper to segment its capacity and make deliveries, on a secondary basis, to and from multiple points within any zone for which it pays reservation charges unavoidably involves utilization of points for which a shipper has not contracted for primary firm delivery rights. Notwithstanding this fact, Texas Eastern appears to argue at many points in its Rehearing Request that a shipper's right to make such deliveries is limited to the primary firm point rights established in its service contract. This assertion is completely contrary to established Commission policy. Further, it only makes sense if the reader, as Texas Eastern apparently did, declines to recognize the secondary nature of at least part of the FH-BH transactions subject to the Commission policy.⁶

In sum, Texas Eastern has premised much of its rehearing argument on a failure to recognize the substantial difference between primary firm and secondary capacity rights. Whether this failure is the result of confusion or artifice is not clear but in either case, the fact remains that the majority of Texas Eastern's arguments are based on a false premise – that the Commission's FH-BH transaction policy establishes primary firm rights for

⁶As was noted above, the FH-BH transactions approved by the Commission can be either part primary firm and part secondary, or they can be completely secondary in nature depending on the shipper's selection of receipt and delivery points; however, they can never consist of two primary firm transactions.

both the forwardhaul and backhaul component of such transactions. Given that this premise is demonstrably false, Piedmont submits that Texas Eastern's arguments provide no basis for a reversal or modification of the Commission's *Order on Remand*.

II. THE COMMISSION HAS NOT MODIFIED ANY CONTRACTS BUT HAS IMPLEMENTED ITS ORDER NO. 636 SEGMENTATION AND SECONDARY DELIVERY FLEXIBILITY POLICIES.

Contrary to the assertions of Texas Eastern, the Commission has not modified any interstate pipeline/customer contracts as the result of the FH-BH transaction policy announced in Order No. 637 and reaffirmed in the Commission's *Order on Remand*. What it has modified, or perhaps clarified is a better word, is the application of its general and longstanding policies announced in Order No. 636, to the specific forwardhaul and backhaul transactions addressed in this proceeding. As such, it is simply inaccurate to contend, as does Texas Eastern, that the Commission's actions in this docket are the result of and premised upon a modification of existing customer contracts.

As was discussed previously, in its *Order on Remand* the Commission has not changed the rights of any shipper or any pipeline with respect to the scheduling, delivery or utilization of primary firm capacity. It is these rights that are addressed by the service contracts between shippers and interstate pipelines. Instead, all the Commission has done is to find, pursuant to section 5 of the NGA, that FH-BH transactions, where operationally feasible, are consistent with its general policies on segmentation and secondary delivery flexibility and required pipelines to change their tariffs to permit these

transactions. Texas Eastern appears to argue that its tariff is a “contract” and that the Commission cannot lawfully change pipeline tariffs without a pipeline’s consent. That assertion, however, is clearly contrary to law and the Commission’s inherent authority under Section 5 to change and implement its policies through pipeline compliance filings where necessary to protect the public interest. In its *Order on Remand*, the Commission correctly concluded that its FH-BH transaction policy did not interfere with individual service agreements and that it was appropriate under Section 5 to direct pipelines to amend their tariffs to permit such transactions where operationally feasible. This finding need only be and in this case was supported by a Commission finding that disallowance of such transactions is unjust and unreasonable.⁷ In fact, the Commission supported its Section 5 determination with specific findings justifying its requirement that pipelines amend their tariffs to permit, where operationally feasible, FH-BH transactions. As such, it is clear that the Commission has not modified any service contracts as a result of its Section 5 finding that pipeline tariffs that do not permit FH-BH transactions (for other than strict operational reasons) are unjust and unreasonable and must be modified to permit such transactions.

As the Commission explained in its *Order on Remand*, this conclusion is completely consistent with the progressive implementation of the Commission’s Order No. 636 policies on segmentation and secondary receipt

⁷*Interstate Natural Gas Association of America v. FERC*, 285 F.3d 18, 38 (D.C. Cir. 2002). Texas Eastern argues that the Commission has a Section 7 burden in implementing its policies but that argument is based on the false premise that pipeline contracts are being modified as a result of the Commission’s Order.

and delivery flexibility because the FH-BH transactions at issue in Texas Eastern's Rehearing Request are simply a form of the flexible segmented secondary delivery rights established by the Commission in Order No. 636.⁸ As the Commission noted, they are not in any way materially different from other secondary segmented transactions authorized by that Order. As such, these FH-BH transactions represent simply the implementation of the Commission's longstanding policies, announced in Order No. 636, permitting maximum flexibility to firm shippers paying reservation charges to utilize the capacity to which they subscribe in as flexible a fashion as possible.

In Order No. 636, the Commission established its policy allowing firm transportation customers on interstate natural gas pipelines to segment their capacity rights within zones for which they pay reservation charges. This policy affords shippers with the right and ability to effectively carve their mainline capacity rights up into various segments thereby allowing such shippers, and third parties to whom such capacity is released, to engage in multiple receipt and delivery transactions within the zones for which the underlying firm transportation customer pays reservation charges.

Commission policy requires that firm shippers paying a reservation charge for a zone have the right to use all the capacity in the zone up to their contract entitlement. Thus, firm shippers may nominate service at any point in the zone on a secondary basis, regardless of the location of their primary points within the zone.

Tennessee Gas Pipeline Company, 85 FERC ¶ 61,052 (1998). By implementing the segmentation flexibility announced in Order No. 636, the Commission was effectively permitting

⁸Backhaul transactions undertaken under a primary firm forwardhaul contract are, by definition, secondary in nature because they utilize receipt and/or delivery points other than the primary points designated in the shipper's service contract.

firm shippers to utilize some of the flexibility previously available to pipelines under their merchant function operations.

Also under Order No. 636, the Commission implemented a policy permitting firm shippers and their replacement shippers to utilize all available receipt and delivery points on interstate natural gas pipelines, on a secondary priority basis, in order to receive and make deliveries of gas.

Order 636 expanded shippers' rights with respect to flexible receipt and delivery points . . . by including the right to receive gas from any person at any place on the system and the right to deliver gas to any person at any place on the system on a firm basis, with the flexibility to change firm receipt and delivery points and to use all delivery points on an interruptible basis.

Order 636-A, *FERC Regulations Preambles*, ¶ 30,950 at p. 30,582. This flexibility complemented the segmentation rights discussed above and allowed subscribers of firm pipeline capacity to more fully utilize the capacity to which they subscribed.⁹

Finally, the Commission expressly anticipated that the use of the segmentation and flexible point rights afforded firm shippers (and their replacement shippers) under Order No. 636 could permissibly result in the total delivery of volumes greater than the underlying firm transportation contract entitlements.

[A]s indicated in prior Commission orders, the total amount of gas delivered in a zone following a series of non-overlapping released segments within a zone can exceed the releasing shipper's original contract entitlement level.

Tennessee Gas Pipeline Company, 85 FERC ¶ 61,052 (1996).

These changes in Commission policy took the first major steps toward creating a competitive interstate natural gas pipeline grid, where shippers could use the capacity they

⁹The flexibility created by the Commission's segmentation and flexible receipt and delivery point rights policies in Order No. 636 was further supplemented by the right to release pipeline capacity to replacement shippers.

contracted for not only to facilitate flexible deliveries for their own use but could also utilize that capacity to compete with the pipelines themselves – through capacity release transactions – when the capacity was not needed to serve their own customers.

The Commission also made it clear that the segmentation flexibility created by Order No. 636 was equally applicable to forwardhaul and backhaul transactions.

In Order Nos. 636 and 636-A, the Commission established the general principle that firm shippers should be able to make full use of their pipeline capacity through release transactions. The Commission used as an example a releasing shipper with capacity between the Gulf of Mexico and New York releasing capacity from the Gulf to Atlanta; this transaction would then free up an equal amount of capacity from Atlanta to New York which the shipper could release or use itself. The releasing shipper could release its capacity in this manner even though the total amount of gas delivered from the two transactions could exceed its total reservation quantity from the Gulf to New York. This principle should be applied to capacity release arrangements between releasing and replacement shippers that involve backhauls or exchanges.

Order 636-B, 61 FERC ¶ 61,272 at p. 61,997.

Following implementation of Order No. 636, the actual use of segmented and flexible receipt and delivery point transactions developed slowly. Initially, the Commission disallowed several attempts to deliver gas on a forwardhaul and backhaul basis to the same point on the basis of concerns that such transactions resulted in “overlapping” mainline transportation in excess of the underlying shippers contract entitlements.¹⁰ As the Commission’s policy on competition in the gas transportation market developed, however, the Commission recognized that its policy on segmentation and flexible point rights encompassed simultaneous forwardhaul/backhaul transactions to the same administrative or notional point.¹¹ And in Order No. 637, the Commission took the final logical step of approving FH-BH transactions to a

¹⁰ *See Iroquois Gas Transmission System*, 77 FERC ¶ 61,352 (1996).

¹¹ *Transcontinental Gas Pipeline Corporation*, 91 FERC ¶ 61,031 (2000).

physical point, where such deliveries were operationally feasible. This final recognition by the Commission, viewed in the context of the Commission's Order No. 636 policies on segmentation, capacity release, and flexible receipt and delivery point rights, reveals that the policy is in no way "new" but simply the product of longstanding Commission policies applied to a specific form of transaction.

The use of a secondary backhaul transaction in conjunction with a firm (or secondary) forwardhaul transaction to deliver volumes to a single point in excess of the TCQ of the underlying contract is completely consistent with the Commission's policies on segmentation, capacity release and flexible receipt and delivery point rights established in Order No. 636. These transactions utilize segmented backhaul transportation in conjunction with secondary delivery rights to transport gas on an operationally-dependent basis to the delivery point where it is most desired either by the customer who has paid reservation charges for the entire zone of the transaction or by its replacement shipper. These transactions simply represent the use by shippers of the capacity rights the shippers have paid for in as efficient a manner as possible to make the maximum deliveries possible for their own use or for the use of others. The policy that permits these transactions is not new but simply the natural conclusion of the Commission's movement toward a more competitive interstate natural gas transportation market. The flexibility provided by such transactions enhances the ability of firm shippers (or their replacement shippers) to compete with the pipelines themselves in providing service to other customers.

III. THE COMMISSION HAS NOT CHANGED PIPELINE CERTIFICATE LEVELS, DOUBLED SHIPPER CAPACITY RIGHTS OR REQUIRED PIPELINES TO GIVE AWAY FREE SERVICE.

In its Rehearing Request, Texas Eastern argues that the Commission has unilaterally changed pipeline certificate levels, doubled shipper capacity rights and required pipelines to give away service. None of these assertions is accurate or even based on fact.

Texas Eastern contends that the Commission's Order on Remand "compels the doubling of service to all firm, open-access shippers on affected pipelines," and that this constitutes a unilateral expansion of pipeline certificate obligations without proper findings under Section 7 of the NGA. This argument, as creative as it may be, does not survive even cursory scrutiny because it is based on the false premise that the Commission's FH-BH transaction policy creates an obligation for pipelines to deliver twice each customer's primary firm capacity entitlements. This argument is completely refuted by the nature of the FH-BH transaction, however, which involves (at most) a single delivery of primary firm capacity and a concurrent delivery of secondary volumes with a lower nomination priority. In short, the only certificate obligation of the pipeline under the Commission's policy remains the delivery of the primary firm forwardhaul volumes. The obligation to permit a nomination of a concurrent secondary firm backhaul delivery is nothing more than an exercise of the secondary delivery and segmentation flexibility established in Order No. 636 and imposes no firm obligation on the pipeline to make such deliveries.

Nor has the Commission permitted shippers to double their capacity entitlements as repeatedly asserted by Texas Eastern. Delivery entitlements, in the FERC vernacular, refer to primary firm capacity rights but not to

segmented or secondary deliveries. This is readily apparent when the nature of the rights associated with primary firm capacity are compared to secondary or segmented capacity. As a general rule, and upon compliance with the relevant nomination and scheduling procedures, a shipper is entitled to the delivery of its primary firm volumes on a daily basis and those volumes may not be curtailed (except in emergency situations) in favor of the transportation of any other shipper's gas. Secondary volumes are, by definition, operationally dependent in nature and subject to both available mainline and delivery point capacity behind all scheduled primary firm transactions. While it is possible to deliver in excess of a shipper's TCQ utilizing a FH-BH transaction, such a delivery is not a matter of absolute right and does not constitute a doubling up of capacity rights.¹²

Finally, there is nothing about FH-BH transactions that constitutes a free give-away of capacity. First, pipeline rates are designed to be fully compensatory based upon the recovery of fixed costs through reservation charges associated with primary firm capacity rights and variable cost recovery through volumetric charges. In the case of a secondary backhaul transaction, such a transaction has absolutely no effect upon the obligations of primary firm shippers to pay reservation charges and it may actually increase pipeline revenues both because of the increased volumetric charges associated with the transaction and the fact that backhaul transactions are delivered through displacement thereby creating additional capacity on the

¹²As was noted above, Order No. 636 expressly permitted the total cumulative delivery of more than a shipper's TCQ through non-overlapping segmentation transactions.

pipeline as well as saving fuel costs.¹³ Second, FH-BH transactions (and all secondary delivery transactions) were approved by the Commission on the premise that shippers utilizing such transactions had essentially paid all of the pipeline's fixed costs (including its margin) in the zone wide reservation charges associated with primary firm capacity entitlements and were, therefore, entitled to use the capacity and facilities they had paid for in as flexible a manner as possible. In light of these facts, the notion that a FH-BH transaction is somehow a giveaway of free service is nonsensical.

IV. TRANSACTIONS EQUIVALENT TO FH-BH CAN BE READILY AND LAWFULLY CONDUCTED ON INTERSTATE PIPELINES ON A DAILY BASIS WITHOUT OBJECTION OR DAMAGE TO THE PIPELINES.

Texas Eastern predicts dire economic consequences for pipelines if the Commission does not reverse its FH-BH transaction policy. That prediction, however, flies in the face of the fact that (1) shippers may lawfully engage in completely equivalent transactions through third parties in complete conformance with Commission regulations and pipeline tariffs, and (2) pipelines themselves have made substantially similar deliveries through displacement and exchanges for decades. As such, the objections of Texas Eastern to the ability of a shipper to deliver simultaneous forwardhaul and backhaul volumes to a point

¹³Piedmont believes that Texas Eastern's arguments are driven primarily by the fact that its rates are calculated on a basic SFV rate design. Under the Commission's current rate design methodology, the primary opportunity for pipelines to increase their bottom line comes in the form of capturing new firm business that can be subjected to reservation charges. Texas Eastern perceives FH-BH transactions to be a threat to this ability and would much prefer to sell additional primary firm forwardhaul capacity to shippers and to retain backhaul flexibility for its own interruptible services. This would allow Texas Eastern to simultaneously expand its revenues and diminish competition for its IT services.

utilizing that shipper's own capacity should be summarily rejected and perceived for what it is, an unwarranted attempt by Texas Eastern to stifle competition.

As discussed above, under Order No. 636, firm transportation customers have the right to segment their capacity into one or more segments and to release these segments of their primary firm capacity to replacement shippers. Along with the released segment of primary firm capacity, the replacement shipper acquires the right to utilize secondary delivery points within the zone in which the segment is released. The only material restriction on this right is the requirement that any overlapping mainline nominations within the zone and originating from the same base contract not exceed the TCQ associated with that contract within any segment of the pipeline's transmission facilities. These are the normal release and flexible point rights created by Order No. 636.

Utilizing these rights, a shipper holding firm transportation capacity on an interstate pipeline can release a segment of upstream capacity to a replacement shipper who can then nominate a backhaul transaction on the separate release contract from a downstream source of supply to a designated Delivery Point A utilizing the secondary delivery flexibility associated with the released segment. Simultaneously, the original shipper can nominate a primary firm forwardhaul transportation transaction of its full TCQ to the same point A. This results in exactly the same delivery of gas that is the subject of remand, the only difference is that two parties nominate the transactions, rather than one.

In addition, primary firm shippers on an interstate pipeline system can effect the same result by engaging in a volumetric "swap" with a downstream shipper in the same zone. In this scenario, a shipper would schedule its primary firm forwardhaul TCQ for delivery to Delivery Point A and then schedule (with the agreement of a downstream shipper) additional volumes for delivery from a downstream source of supply to the downstream shipper at Delivery Point

B. In return, Shipper B would drop off a corresponding amount of its firm forward haul entitlements at Delivery Point A utilizing its secondary delivery point rights, with such amount to be replaced by the receipt of quantities downstream at Point B.

It should be noted that under either of the previous two examples of legitimate alternative transportation transactions, the same amount of commodity revenues are generated as in a simultaneous forwardhaul/backhaul transaction under one contract. Therefore, any concern raised by pipelines that additional revenues to credit to a pipeline's cost of service (or its bottom line) are being foregone under the transaction in question is unfounded in fact.

Given that these equivalent transactions are plainly consistent with the Commission's segmentation, release and secondary delivery policies, it makes no sense to restrict a shipper from accomplishing the same result using its own capacity. If Texas Eastern were to prevail on this issue, it would establish several peculiar anomalies in the Commission's policy. First, it would allow shippers to utilize their segmentation rights and secondary delivery flexibility to serve other parties using downstream sources of supply but would not allow those shippers to serve themselves using that capacity. Second, it would allow replacement shippers to deliver backhaul volumes on a secondary basis to some delivery points while the firm contract holder of the underlying capacity would be barred from engaging in such a transaction.

These disparities in the respective rights of both replacement shippers and exchange shippers as compared to the holders of the underlying firm capacity are nonsensical and illustrate the fundamental lack of "Beef" in Texas Eastern's arguments. In short, there is simply no rational reason that occurs to Piedmont why a replacement shipper should have greater secondary delivery rights than the releasing shipper it obtains its capacity from. It further makes no sense that a primary firm shipper can use its downstream secondary delivery flexibility to

serve other parties but not itself. These obvious conclusions clearly illustrate the lack of merit in Texas Eastern's arguments.

V. FH-BH TRANSACTIONS PROVIDE MULTIPLE BENEFITS TO THE INTERSTATE NATURAL GAS CAPACITY MARKET.

In its rehearing request, Texas Eastern argues that the Commission is wrong in finding that FH-BH transactions will provide benefits to shippers and the interstate capacity and supply markets. Texas Eastern is mistaken in this regard as such transaction will have several beneficial effects on those markets.

First, FH-BH transactions will substantially enhance competition between pipelines and capacity holders as well as between suppliers. This will occur because of the access made available to downstream supply sources and the ability to deliver those volumes to any of the delivery points within the zones for which a shipper pays reservation charges. This will promote competition between pipeline IT service and secondary capacity but will have no effect on primary firm capacity rights because such secondary backhauls are subject to the pipeline's operational ability to provide such deliveries. It will also have a beneficial impact on competition between upstream and downstream sources of supply as a result of enhancing the accessibility to such downstream supply sources within zones for which a shipper pays reservation charges and will promote the growth of downstream supply sources.

Second, FH-BH transactions will make released capacity more flexible and valuable, allowing replacement shippers greater flexibility to utilize released capacity in the most efficient manner possible. This in turn will make

the underlying primary firm capacity contracts more valuable because of the attendant right to release that capacity.

Third, FH-BH transactions will promote greater and more efficient use of the interstate pipeline grid the net effect of which should be to ensure delivery of gas at the lowest possible price. This will also help minimize the need for additional capital investments to construct new forwardhaul capacity and will also contribute to the Commission's goal of expanding natural gas transportation to a level of 30 TCF.

Finally, all of this will be done without threat of harm to pipeline operational integrity because of the secondary interruptible nature of the backhaul component of FH-BH transactions and the "operational feasibility" standard set forth in the Commission's policy.

In sum, there are substantial competitive benefits to permitting FH-BH transactions which justify and support the Commission's decision in its *Order on Remand*.

CONCLUSION

For the foregoing reasons, Piedmont Natural Gas Company, Inc. respectfully requests that the Commission accept its Answer to Texas Eastern's Rehearing Request as set forth above and deny Texas Eastern's Rehearing Request for the reasons set forth herein.

Respectfully submitted, this the 9th day of January, 2003.

Piedmont Natural Gas Company, Inc.

/s/ James H. Jeffries IV
James H. Jeffries IV

Jerry W. Amos

OF COUNSEL:

Nelson Mullins Riley & Scarborough, L.L.P.
Bank of America Corporate Center
100 North Tryon, Suite 2400
Charlotte, North Carolina 28202-4000
Telephone: 704-417-3000

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing document is being served upon each person designated on the official service list compiled by the Secretary in this proceeding by depositing a copy of the same in the United States Mail, First Class Postage Prepaid, to their last known address.

This the 9th day of January, 2003.

/s/ Sonya R. Lowe
Sonya R. Lowe

TRA DOCKET NUMBER 07-00224

EXHIBIT D



Terms and Definitions

[A](#) [B](#) [C](#) [D](#) [E](#) [F](#) [G](#) [H](#) [I](#) [J](#) [K](#) [L](#) [M](#) [N](#) [O](#) [P](#) [Q](#) [R](#) [S](#) [T](#) [U](#) [V](#) [W](#) [X](#) [Y](#) [Z](#) :: [Acronyms](#)

Terms	Descriptions
ALERT DAY	When Transporter determines that the pipeline is experiencing or may experience in the next gas day high or low line pack operating conditions which threaten the ability to render firm services
ALERT DAY NOTICE	Notice issued by the Transporter when, at its sole discretion, reasonably exercised, Transporter determines that the pipeline is experiencing or may experience in the next Gas Day high or low line pack operating conditions which threaten the ability to render firm services
APPLICATION	A form required by the Company to be completed and signed by prospective customers requesting gas service
ATMOSPHERIC PRESSURE	Fourteen and seventy-three hundredth (14.73) pounds to the square inch, irrespective of actual elevation or location of the point of measurement above sea level or variations in atmospheric pressure from time to time.
BILLING ADJUSTMENT - BTU	A conversion factor representing the BTU content per cubic foot used to convert cubic feet to therms for billings to customers. The BTU content shall be the BTU per cubic foot as report by the transporting pipeline.
BILLING PERIOD	Regular monthly period in which the Company reads meter

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- [Builders & Developers](#)
- [Commercial & Industrial](#)
- [Energy Plus Partners](#)
- [FAQs](#)
- [Press Room](#)

CUSTOMER	Any individual, firm, or organization receiving gas service at one location and/or other services rendered by the Company under this tariff and provisions thereof. Reserved for future use.
CUSTOMER'S INSTALLATION	All pipe and fittings, regulators, cocks, valves, vents, circulating pipes, connections, appliances, and apparatus of every kind and nature used in connection with or forming a part of an installation for utilizing gas for any purpose located on the outlet side of the Company's meter located on Customer's premises.
CUSTOMER POOL	A group of customers that either 1) elect, in accordance with the applicable transportation provisions, Transportation Aggregation Service with an approved Pool Manager, or 2) are assigned to the Transitional Transportation Service Pool Manager.
DEKATHERM	1,000,000 BTU's (1 MMBTU) or ten (10) therms.
DELIVERY GAS DAY	A period of twenty-four (24) consecutive hours beginning and ending at 9:00 a.m. Central Clock Time.
DELIVERY POINT or POINT OF DELIVERY	(a) The point at the connection of the facilities of Transporter and of a downstream third party at which the gas leaves the outlet side of Transporter's measuring equipment and enters the downstream party's facilities, OR (b) The point at the interconnection between the facilities of Company and a Customer (sales or transportation) at which the gas leaves the outlet side of Company's measuring equipment and enters the Customer's facilities.
DELIVERY POINT OPERATOR	The Company, as Delivery Point Operator (DPO) is the party responsible for managing gas supply allocations, operational orders, imbalance resolutions and other related duties, including monetary transactions between upstream interstate pipelines and the Company and between downstream third-party Shippers and the Company

TRA DOCKET NUMBER 07-00224

EXHIBIT E

ORIGINAL
Chattanooga Gas Company

6125 Preservation Drive

Chattanooga, TN 37416

Telephone: 1-800-427-5463

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 FEDERAL ENERGY
REGULATORY COMMISSION

August 26, 2002

Honorable Magalie Salas
 Acting Secretary
 Federal Energy Regulatory Commission
 888 First Street NE
 Washington, DC 20426

EM02-7-000

Re: Initial Report of Transaction under 18 C.F.R. § 284.270

Dear Ms. Salas:

Pursuant to 18 C.F.R. § 284.270, Chattanooga Gas Company ("CGC") files this initial report of an emergency natural gas transaction. On August 26, 2002, CGC commenced the transfer of emergency natural gas supplies in the form of liquefied natural gas ("LNG") from Atlanta Gas Light Company's ("AGLC") Riverdale LNG facility.

This emergency transaction is necessitated by the fact that, in September 2001, the refrigeration compressor utilized at CGC's LNG plant suffered mechanical damage that resulted in the loss of liquefaction capability at the plant. The loss has been duly reported to the appropriate Commission personnel. The replacement of this compressor, scheduled for installation in August of 2002, has been delayed to a delivery date of October 2, 2002 due to operational problems on behalf of the vendor, York International Corporation. The time required for installation operations will not allow liquefaction of LNG to begin until an estimated date of November 4, 2002. As a result, CGC needs additional LNG to ensure that service to its firm end-use customers is not disrupted this winter.

To make up the shortfall caused by the loss, CGC has arranged to transfer liquefied natural gas from AGLC's Riverdale LNG Plant. CGC will arrange to transport natural gas to AGLC's city gate using firm transportation under its FT contracts with Southern Natural Gas Company, East Tennessee Natural Gas Company and Tennessee Gas Pipeline Company. A like volume of LNG will be injected into tanker trucks at AGLC's LNG facilities in Georgia and transported by truck to CGC's LNG storage tank in Tennessee. CGC will exchange between 8500 – 10,000 Dt/Day or about 620,000Dth of LNG with AGLC for the term of the emergency. CGC will pay AGLC the cost of liquefaction of \$1.50/DT plus the associated fuel. CGC has arranged for the transportation of the LNG by truck at a cost of \$635 per load. It is contemplated that it

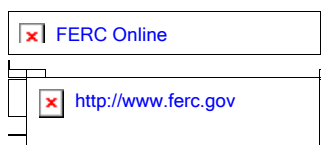
will take approximately 600 truckloads of LNG. Trucking commenced on August 26, 2002, and is estimated to be completed by November 20, 2002. The participants in the transaction are CGC, AGLC, and Southeastern LNG, Inc., which will provide the trucking service.

Please do not hesitate to contact me if you have any questions regarding this report.

Sincerely,


Isaac Blythers
President

cc: Eddie Conder
John Ebert
Eileen Goldsack



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Submittal 20061208-0193	12/04/2006 12/05/2006	EM07-2-000	Chattanooga Gas Company pursuant to 18 CFR Section 284.270 submits initial report of an emergency natural gas exchange transaction under EM07-2. Availability: Public	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	44K 59K	INFO FILE
Submittal 20040402-0063	03/31/2004 04/01/2004	EM04-4-000	Chattanooga Gas Co submits a verified Termination Report for an emergency natural gas transaction initially reported to FERC on 1/7/04 under EM04-4. Availability: Public	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	64K 91K	INFO FILE
Submittal 20040112-0368	01/07/2004 01/08/2004	EM04-4-000	Chattanooga Gas Co submits its initial report of an emergency natural gas transaction under EM04-4. Availability: Public	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	38K 52K	INFO FILE
Submittal 20030401-0351	03/25/2003 03/31/2003	EM02-1-000	Chattanooga Gas Co submits verified termination report for an emergency natural gas transaction initially reported to the Commission on 1/27/03 under EM02-1. Availability: CEII	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	62K 87K	INFO FILE
Submittal 20030401-0358	03/25/2003 03/31/2003	EM02-1-000	Chattanooga Gas Co submits a Termination Report for an emergency natural gas transaction initially reported to FREC on 1/27/03 under EM02-1. Availability: CEII	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	62K 89K	INFO FILE
Submittal 20030206-0137	01/27/2003 02/03/2003	EM03-3-000	Chattanooga Gas Co's initial report of an emergency natural gas transaction pursuant to 18	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	31K 41K	INFO FILE

[CFR, Section 284.270](#)

[under EM03-3.](#)

Availability: CEII

Submittal 20021230-0064	12/09/2002 12/23/2002	EM02-1-000	Chattanooga Gas Co submits verified termination report for an emergency natural gas transaction initially reported to FERC on August 26, 2002 under EM02-1.	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	63K 86K	INFO FILE
			Availability: CEII				
Submittal 20020910-0074	08/26/2002 09/03/2002	EM02-7-000	Chattanooga Gas Co submits an initial report of an emergency natural gas transaction from Atlanta Gas Light Co's Riverdale LNG facility under EM02-7.	Report/Form / Emergency Gas Report	☐ Image ☐ FERC Generated PDF	44K 58K	INFO FILE
			Availability: Public				
Submittal 20020227-0317	02/05/2002 02/25/2002	EM02-1-000	Chattanooga Gas Co submits Termination Report for an emergency natural gas transaction initially reported to the Commission on 10/2/01 under EM02-1.	Report/Form / Emergency Gas Report	☐ Image	93K	INFO FILE
			Availability: CEII				
Submittal 20011011-0283	10/02/2001 10/03/2001	EM02-1-000	Chattanooga Gas Company submits an initial report of an emergency natural gas transaction that commenced on 10-01-01 for exchange of emergency natural gas from Atlanta Gas Light Co under EM02-1.	Report/Form / Emergency Gas Report	☐ Image	48K	INFO FILE
			Availability: CEII				
Submittal 20010329-0091	03/20/2001 03/26/2001	EM01-1-000	Chattanooga Gas Company submits a termination report for the emergency natural gas transaction reported to FERC on November 30, 2000 under EM01-1.	Report/Form / Emergency Gas Report	☐ Image	101K	INFO FILE
			Availability: CEII				
Submittal 20001212-0491	11/29/2000 11/30/2000	EM01-1-000	Chattanooga Gas Company submits initial report of an emergency natural gas supply transaction under EM01-1.	Report/Form / Emergency Gas Report	☐ Image	37K	INFO FILE
			Availability: CEII				

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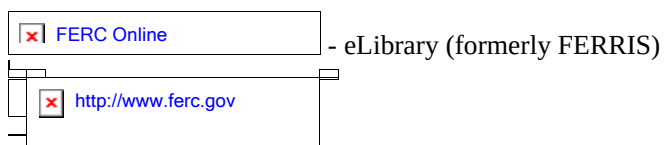
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Type:

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Affiliation Type:

Affiliation Author:

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TRA DOCKET NUMBER 07-00224

EXHIBIT F

Investors are paying 80% more than book value for these stocks, and the returns on book value are generally above 7%. Thus investors are requiring a market return (the cost of equity capital to the utility) far below Dr. Morin's 11.5% return.

VIII. The Declining Demand Of Small Customers Is Not A Risk Factor

Q_37. Has Dr. Morin identified certain risks in particular that caused him to choose 11.50% as a rate of return?

A_37. Yes. He has identified "demand risks" as a factor influencing his opinion:

- *" the demand risks faced by CGC are higher than those of other gas utilities...the usage per residential customer declines and continues to decline... the demand for increased gas volumes is virtually non-existent... as a result the Company's demand risks exceed those of the industry." [Morin Direct Page 51, lines 4-18]*

Q_38. Do you agree with his opinion?

1 A_38. No. I disagree with his opinion. He has
2 overlooked the substantial revenue stream
3 that flows to the Company from its sales
4 of capacity not used by the small
5 customer.

6
7 On April 22, 1999 AGL filed comments with
8 Federal Energy Regulatory Commission in
9 FERC dockets RM98-10-000 and RM98-12-000.
10 The comments included an affidavit by
11 Professor Richard J. Pierce, who explained
12 the benefits that low load factor
13 customers, such as the residential class
14 referred to by Dr. Morin, confer on their
15 service provider. Dr. Pierce's reference
16 point was Georgia and Atlanta but his
17 comments apply equally well to Chattanooga
18 Gas and its small customers.

19
20 To make this point well understood, I have
21 provided a copy of the cover page of AGL's
22 correspondence to FERC on the next page.
23 Following that, I have quoted from Dr.
24 Pierce's affidavit, selectively
25 substituting the term "CGC" for the word
26 "marketer" to demonstrate the relevance of
27 the issue in this docket before the
28 Authority.

ORIGINAL

**LONG ALDRIDGE
& NORMAN^{LLP}**
ATTORNEYS AT LAW

KEVIN M. DOWNEY
202-824-1241

FILED
OFFICE OF THE SECRETARY

99 APR 22 PM 3:51 EMAIL ADDRESS
kdowney@lanlaw.com

April 22, 1999

FEDERAL ENERGY
REGULATORY COMMISSION

Mr. David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Regulation of Short-Term Natural Gas Transportation Services and
Regulation of Interstate Natural Gas Transportation Services,
RM98-10-000 and RM98-12-000

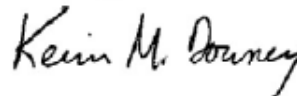
Dear Mr. Boergers:

Enclosed for filing with the Commission in the above-captioned proceedings are an original and fourteen copies of the "Comments of Atlanta Gas Light Company." Also enclosed is a 3.5" diskette containing electronic versions of the Comments and the affidavit of Professor Richard J. Pierce, Jr., which is attached as Appendix A to the Comments, in WordPerfect 6.1 format; however, the diskette does not contain the attachments to Professor Pierce's affidavit.

Kindly acknowledge receipt of the enclosures by date-stamping and returning the designated copies to our messenger.

Thank you for your cooperation in this matter.

Sincerely,



Kevin M. Downey

Enclosures

FERC DOCKETED

APR 22 1999

1
2

1 Dr. Pierce stated in part:

- 2
- 3 • *Retailing gas to small customers is characterized*
- 4 *by high costs per transaction and low benefits per*
- 5 *transaction. The high costs have two components:*
- 6 *marketing costs and the costs required to contract*
- 7 *for an adequate combination of distribution*
- 8 *capacity, pipeline capacity, and storage. AGLC*
- 9 *concluded that it had little ability to effect the*
- 10 *marketing costs, so it concentrated on minimizing*
- 11 *the second category of costs. Those costs are*
- 12 *extremely high per small customer because most*
- 13 *small customers have very low load factors.*
- 14 *...[CGC]... must arrange for capacity that is*
- 15 *sufficient to meet its contractual obligations on a*
- 16 *peak day, even though it will use only a small*
- 17 *fraction of that capacity on most days....*
- 18

-
- 1 • *“The capacity ... is essential to provide service to*
2 *...[CGC]...s’ small customers on peak days. On*
3 *most days, however,...[CGC]... will have excess*
4 *capacity that it is free to use to make interruptible*
5 *sales to large customers. ...[CGC]... is free to use*
6 *any excess interstate capacity to serve customers*
7 *outside of [Tennessee]... as long as the ...[CGC]...*
8 *has sufficient interstate capacity available to meet*
9 *the firm requirements of the consumers that it must*
10 *serve. Because of the extremely low load factor of*
11 *small customers...[CGC]... can market excess*
12 *capacity in the secondary interstate capacity*
13 *market. In an average year, AGLC’s small*
14 *customers use less than one-half of their peak day*
15 *capacity on all but 22 days per year. Thus, each*
16 *small customer.... brings with it the additional*
17 *benefit of enabling ...[CGC]... to make interruptible*
18 *sales to large customers. This... creates a win-win*
19 *situation for small and large customers.”*
20

21 Q_39. **Do you agree with the opinions expressed**
22 **in the affidavit?**

23
24 A_39. I agree with the opinion that “each small
25 customer...brings with it the additional
26 benefit of enabling ...[CGC]” to sell
27 capacity in the interstate market or to
28 interruptible customers.
29

1 However, I do not agree that it is a "win-
2 win situation" for consumers. Because all
3 purchased gas costs (which include
4 capacity costs that must be paid to the
5 pipelines) are automatically passed on to
6 Tennessee's consumers via the PGA, there
7 is incentive for the Company or its agent,
8 Sequent, to craft gas-supply plans that
9 build in excess capacity.

10
11 For example, there is incentive to select
12 year-round capacity agreements as the
13 principal means of meeting the needs of
14 small customers even though as Dr. Pierce
15 said "small customers use less than one-
16 half of their peak day capacity on all but
17 22 days per year," a situation in which
18 seasonal contracts would be appropriate.

19
20 Sensibly enough from the Company's
21 perspective, there is incentive to extend
22 the life of existing year-round contracts
23 rather than relinquishing or "turning
24 back" the capacity to the pipeline even
25 though pipeline tariffs allow such a
26 reduction without penalty. Part of CGC's
27 gas supply is provided through the
28 Southern Natural Gas Pipeline. In the
29 event the Authority ordered CGC to reduce
30 its transportation capacity, the
31 pipeline's tariff allows CGC to reduce its
32 contract demand without penalty just 90
33 days after such an order:

Superseding: Second Revised Sheet No. 212GGENERAL TERMS AND CONDITIONS
(Continued)**39. TRANSPORTATION DEMAND ADJUSTMENT FOR STATE REGULATORY ACTION**

(a) If SHIPPER is a local distribution company, or a Hinshaw pipeline under Section 1(c) of the Natural Gas Act, subject to the jurisdiction of a state regulatory agency, and if said state regulatory agency issues a final order that (i) finds SHIPPER'S aggregate firm transportation quantities with all of its pipeline transporters to be excessive when compared to its requirements for firm transportation service necessary to serve all of the loads attached to its distribution system, and (ii) requires SHIPPER to reduce such aggregate firm transportation quantities, SHIPPER may reduce its Transportation Demand under any Service Agreement for firm transportation services between SHIPPER and COMPANY by the amount ordered by said state regulatory agency; provided however, that any such reduction shall be applied first to the Transportation Demand under the Service Agreement for which SHIPPER is paying the lowest transportation rate, calculated on a one hundred percent (100%) load factor basis, and then to the Transportation Demand under the Service Agreement with the shortest remaining contract term. For purposes of determining under which Service Agreement Transporter is paying the lowest rate, any seasonally adjusted contracts shall be considered to be discounted contracts, with such discounted transportation rate to be determined by dividing the annual revenues under the Service Agreement by the product of the maximum monthly Transportation Demand times 12. Such reduction shall become effective ninety (90) days after the date of SHIPPER'S written notice to COMPANY that it has been ordered by the state regulatory agency to reduce its Transportation Demand. SHIPPER'S right to reduce its Transportation Demand as provided in this Section 39 is conditioned upon (i) SHIPPER having provided written notice to COMPANY that its aggregate firm transportation quantities were the subject of a state regulatory proceeding so that COMPANY had a reasonable opportunity to participate in said proceeding, and (ii) SHIPPER having made a good faith effort to defend its aggregate firm transportation quantities in said proceeding.

(b) SHIPPER'S right to reduce its Transportation Demand under this Section 39 shall not apply to Service Agreements executed or extended as part of a system expansion or other transaction between COMPANY and SHIPPER where facilities on COMPANY'S system are to be constructed, modified or sold after May 20, 2004, in consideration for the contract subscription or extension; provided, however, once the primary term of such Service Agreement or contract extension has expired, Section 39(a) will apply to any future evergreen periods for Service Agreements covered hereunder. Each package of capacity under SHIPPER'S firm Service Agreement for which this Section 39(b) exclusion applies will be designated by the COMPANY on the Exhibit B to SHIPPER'S Service Agreement

1
2
3
4

1 No company-witness acknowledges that CGC
2 can easily shed excess transportation
3 capacity, and no company-witness
4 acknowledges the benefits Dr. Pierce
5 identified in his affidavit to FERC.
6 Apparently none of the benefits are
7 credited against the revenue requirement
8 filed by the Company, even though the
9 revenues from interstate and interruptible
10 sales certainly increase the company's
11 return.

12
13 **Q_40. How do you know that sales in the**
14 **interstate market increase the Company's**
15 **return?**

16
17 **A_40.** In my opinion this is a reasonable
18 conclusion given what is known about CGC
19 and Sequent.

20
21 For example, September 28, 2005 the SEC
22 issued an order captioned "Release No. 35-
23 28038; 70-10304 AGL Resources Inc. Order
24 Authorizing the Acquisition of Nonutility
25 Businesses and Participation in the System
26 Money Pool."

27
28 The Order commented on Sequent:
29

Dr. Morin has made a mistaken assessment of CGC's demand risks in light of: Dr. Pierce's statements to FERC; the ease with which CGC can shed pipeline capacity; and the SEC's recognition that Sequent "focuses on capturing value from idle or underutilized natural gas assets."

1 Furthermore, CGC's cost-of-service study,
2 which shows the Company making only a 2%
3 return on the residential class, is
4 incomplete because it has not accounted
5 for the benefits that small customers have
6 conferred on CGC and Sequent. Also, the
7 cost-of service study has not identified
8 the "adequate combination of distribution
9 capacity, pipeline capacity, and storage
10 capacity" required to serve consumers.
11 Therefore, my opinion is that the study is
12 not a reasonable guide for allocating
13 costs among rate classes. Thus any rate-
14 change should be distributed evenly across
15 all classes.

16
17
18 This concludes my testimony at this time.
19
20

21 ***IX. Statement of Credentials and***
22 ***Experience***

23
24 **Q_41. What experience do you have regarding**
25 **utilities?**

26
27 **A_41. In 1995 I began work as an economist**
28 **in the Consumer Advocate and**
29 **Protection Division (CAPD) of the**
30 **Attorney General's Office. I have also**
31 **appeared as a witness for CAPD in**
32 **several cases before the Tennessee**
33 **Regulatory Authority (TRA). From 1986**

TRA DOCKET NUMBER 07-00224

EXHIBIT G

1
2
3 Reply to 24 25.
4

5 Please see the attached spread sheet
6 "Reply to CGC DR 24 25.xls." Seasonal
7 contracts are indicated by the following
8 pattern in the contracts - entries of zero
9 or near zero for the quarters starting in
10 April- 200604, in July - 200607, in
11 October - 200610, and then very large
12 numbers for January, such as 200701. The
13 values for the table below is drawn from
14 ETNG's Customer Index and shows ET
15 delivery contracts for 160,148 Dkt as of
16 January 2008. For Atmos refer to contracts
17 30777,30777R1, and 30777R2. For Knoxville
18 refer to contracts 410119, 410119R1, 4342,
19 and 4342R1.
20

21
22 YYYYMM Total Seasonal Capacity DKT
23 200010
24 200101
25 200104
26 200107
27 200110
28 200201 107,785
29 200204 74,989
30 200207 73,796
31 200210 5,751
32 200301 107,785
33 200304 68,814
34 200307 5,751
35 200310 5,751
36 200401 159,372
37 200404 11,715
38 200407 10,036
39 200410 10,036
40 200501 163,657

1	200504	5,751
2	200507	5,751
3	200510	0
4	200601	159,372
5	200604	0
6	200607	0
7	200610	0
8	200701	160,408
9	200704	0
10	200707	0
11	200710	0
12	200801	160,408

YYYYMM	200010	200101	200104	200107	200110	200201
ET Contract	Shipper — Amount UNITED CITIES GAS COMPANY— 1	UNITED CITIES GAS COMPANY— 36547	UNITED CITIES GAS COMPANY IL— 0	UNITED CITIES GAS COMPANY IL— 0	UNITED CITIES GAS COMPANY IL— 0	UNITED CITIES GAS COMPANY IL— 36547
30777						
30777R1						
30777R2						
34798		UTILITIES BOARD— 1000	UTILITIES BOARD— 1000	UTILITIES BOARD— 1000	UTILITIES BOARD— 1000	UTILITIES BOARD— 1000
34798R1						
34798R2						
34800		GAS DEPARTMENT— 1000	GAS DEPARTMENT— 1000	GAS DEPARTMENT— 1000	GAS DEPARTMENT— 1000	GAS DEPARTMENT— 1000
34800R1						
34800R2						
410044					WOLF HILLS ENERGY LLC— 5751	WOLF HILLS ENERGY LLC— 0
410119						
410119R1						
410150						
410150R1						
410164						
410164R1						
410164R2						

410244R1

4331	ATHENS TENNESSEE UTILITIES BOARD-- 1	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 1122

4331R1

4331R2

4335	COOKEVILLE GAS DEPT CITY OF-- 1	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 1341

4335R1

4335R2

4336	PUBLIC UTILITY DISTRICT-- 1	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030

4336R1

4337	UTILITIES DEPARTMENT-- 1	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 134

4337R1

4337R2

4338	E GAS SYSTEM-- 1	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485

4338R1

4340	GALLATIN NATURAL GAS SYSTEM-- 1	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060

4340R1

4341	HAWKINS COUNTY UTILITY DISTRICT-- 1	HAWKINS COUNTY UTILITY DISTRICT-- -	HAWKINS COUNTY UTILITY DISTRICT-- 2837	HAWKINS COUNTY UTILITY DISTRICT-- 2837	HAWKINS COUNTY UTILITY DISTRICT-- 2837	HAWKINS COUNTY UTILITY DISTRICT-- 2837
4341R1						
4341R2						
4342	KNOXVILLE UTILITIES BOARD-- 1	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020
4342R1						
4343	LENOIR CITY UTILITIES BOARD-- 1	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 397
4343R1						
4343R2						
4344	GAS DEPARTMENT-- 1	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699
4344R1						
4344R2						
4347	UTILITIES GAS DEPARTMENT-- -	LOUDON UTILITIES GAS DEPARTMENT-- 438	LOUDON UTILITIES GAS DEPARTMENT-- 438	LOUDON UTILITIES GAS DEPARTMENT-- 438	LOUDON UTILITIES GAS DEPARTMENT-- 438	LOUDON UTILITIES GAS DEPARTMENT-- 438
4347R1						
4348	SOUTH PITTSBURG CITY OF-- 1	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580
4348R1						
4348R2						

4349	TENNESSEE NATURAL GAS UTIL DIST-- 1	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621
4349R1						
4350	POWELL CLINCH UTILITY DISTRICT-- 1	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160
4350R1						
4350R2						
4351	SEVIER COUNTY UTILITY DISTRICT-- 1	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133
4351R1						
4358	JAMESTOWN NATURAL GAS SYSTEM-- 1	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 309
4358R1						
7566	TENNESSEE NATURAL GAS UTIL DIST-- 1	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193				TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193
7566R1						
7566R2						
7568	JEFFERSONCO OCKE CO PUBLIC UTILITY DIST-- 1	JEFFERSONCO OCKE CO PUBLIC UTI-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804

7568R1

7568R2

	COOKEVILLE GAS DEPT CITY OF--	COOKEVILLE GAS DEPT CITY OF--	COOKEVILLE GAS DEPT CITY OF--	COOKEVILLE GAS DEPT CITY OF--	COOKEVILLE GAS DEPT CITY OF--	COOKEVILLE GAS DEPT CITY OF--
7570	1	875	875	875	875	875

7570R1

7570R2

200204	200207	200210	200301	200304	200307	200310
UNITED CITIES GAS COMPANY IL-- 0	UNITED CITIES GAS COMPANY IL-- 0	UNITED CITIES GAS COMPANY IL-- 0	ATMOS ENERGY CORPORATION-- 36547	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0
UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 1000	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0
GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1000	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0
WOLF HILLS ENERGY LLC-- 5751	WOLF HILLS ENERGY LLC-- 5751	WOLF HILLS ENERGY LLC-- 5751	WOLF HILLS ENERGY LLC-- 0	WOLF HILLS ENERGY LLC-- 5751	WOLF HILLS ENERGY LLC-- 5751	WOLF HILLS ENERGY LLC-- 5751

ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 1122	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 0
COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 1341	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0
ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 1030	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0
ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 134	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0
FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 485	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0
GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 2060	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0

HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-
-	-	-	-	-	-	-
2837	2837	0	2837	2837	0	0

KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 0	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 35020	KNOXVILLE UTILITIES BOARD-- 0	KNOXVILLE UTILITIES BOARD-- 0

LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 0	LENOIR CITY UTILITIES BOARD-- 397	LENOIR CITY UTILITIES BOARD-- 0	LENOIR CITY UTILITIES BOARD-- 0	LENOIR CITY UTILITIES BOARD-- 0

LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 0	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 699	LEWISBURG GAS DEPARTMENT-- 0	LEWISBURG GAS DEPARTMENT-- 0

LOUDON UTILITIES GAS DEPARTMEN-- 438	LOUDON UTILITIES GAS DEPARTMEN-- 438	LOUDON UTILITIES GAS DEPARTMEN-- 0	LOUDON UTILITIES GAS DEPARTMEN-- 438	LOUDON UTILITIES GAS DEPARTMEN-- 438	LOUDON UTILITIES GAS DEPARTMEN-- 0	LOUDON UTILITIES GAS DEPARTMEN-- 0

SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 580	SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 0

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 16621	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0
POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 0
SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 1133	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 0
JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0
TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193		TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0
JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0

COOKEVILLE	COOKEVILLE	COOKEVILLE	COOKEVILLE
GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY
OF-	OF-	OF-	OF-
875	875	0	875

COOKEVILLE	COOKEVILLE
GAS DEPT CITY	GAS DEPT CITY
OF-	OF-
0	0

200401	200404	200407	200410	200501	200504	200507
ATMOS ENERGY CORPORATION-- 52633	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 52633	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0
UTILITIES BOARD-- 1000	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 1000	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0
GAS DEPARTMENT-- 1000	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1000	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0
WOLF HILLS ENERGY LLC-- 0 UTILITIES BOARD-- 19498	WOLF HILLS ENERGY LLC-- 5751 UTILITIES BOARD-- 0	WOLF HILLS ENERGY LLC-- 5751 UTILITIES BOARD-- 0	WOLF HILLS ENERGY LLC-- 5751 UTILITIES BOARD-- 0	WOLF HILLS ENERGY LLC-- 0 UTILITIES BOARD-- 19498	WOLF HILLS ENERGY LLC-- 5751 UTILITIES BOARD-- 0	WOLF HILLS ENERGY LLC-- 5751 UTILITIES BOARD-- 0
	UTILITIES BOARD-- 4285	UTILITIES BOARD-- 4285	UTILITIES BOARD-- 4285	UTILITIES BOARD-- 4285	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0
				CKE COUNTY UTILITY DISTRICT-- 1365	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 0

ATHENS UTILITIES BOARD-- 1439	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 1439	ATHENS UTILITIES BOARD-- 0	ATHENS UTILITIES BOARD-- 0
COOKEVILLE GAS DEPT CITY OF-- 2218	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 2218	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0
ELK RIVER PUBLIC UTILITY DISTR-- 1371	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 1371	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0
ETOWAH UTILITIES DEPARTMENT-- 183	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 183	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0
FAYETTEVILLE GAS SYSTEM-- 690	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 690	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0
GALLATIN NATURAL GAS SYSTEM-- 3035	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 3035	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0

HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-	HAWKINS COUNTY UTILITY DISTRIC-
-	-	-	-	-	-	-
4126	0	0	0	4126	0	0

KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--	KNOXVILLE UTILITIES BOARD--
35020	0	0	0	35020	0	0

LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--	LENOIR CITY UTILITIES BOARD--
510	0	0	0	510	0	0

LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--	LEWISBURG GAS DEPARTMENT--
1075	0	0	0	1075	0	0

LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--	LOUDON UTILITIES GAS DEPARTMEN--
730	0	0	0	730	0	0

SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--	SOUTH PITTSBURG CITY OF--
824	0	0	0	824	0	0

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 25450	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 25450	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0

POWELL CLINCH UTILITY DISTRICT-- 3525	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 2160	POWELL CLINCH UTILITY DISTRICT-- 0	POWELL CLINCH UTILITY DISTRICT-- 0

SEVIER COUNTY UTILITY DISTRICT-- 1864	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 1864	SEVIER COUNTY UTILITY DISTRICT-- 0	SEVIER COUNTY UTILITY DISTRICT-- 0

JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0

JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 804	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0	JEFFERSONCO CKE COUNTY UTILITY DISTRICT-- 0

COOKEVILLE	COOKEVILLE	COOKEVILLE	COOKEVILLE	COOKEVILLE	COOKEVILLE	COOKEVILLE
GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY	GAS DEPT CITY
OF--	OF--	OF--	OF--	OF--	OF--	OF--
875	875	0	0	875	0	0

200510	200601	200604	200607	200610	200701	200704

ATMOS ENERGY CORPORATION--	ATMOS ENERGY CORPORATION--
0	52633

ATMOS ENERGY CORPORATION--	ATMOS ENERGY CORPORATION--	ATMOS ENERGY CORPORATION--	ATMOS ENERGY CORPORATION--	ATMOS ENERGY CORPORATION--
0	0	0	52633	0

UTILITIES BOARD--
0

UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--
1000	0	0	0	1000	0	0

GAS DEPARTMENT--
0

GAS DEPARTMENT--	GAS DEPARTMENT--	GAS DEPARTMENT--	GAS DEPARTMENT--	GAS DEPARTMENT--	GAS DEPARTMENT--	GAS DEPARTMENT--
1000	0	0	0	1000	0	0

UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--	UTILITIES BOARD--
0	19498	0	0	0	19498	0

UTILITIES BOARD--	UTILITIES BOARD--
0	0

CKE COUNTY UTILITY DISTRICT--	CKE COUNTY UTILITY DISTRICT--
0	1365

CKE COUNTY UTILITY DISTRICT--	CKE COUNTY UTILITY DISTRICT--	CKE COUNTY UTILITY DISTRICT--	CKE COUNTY UTILITY DISTRICT--	CKE COUNTY UTILITY DISTRICT--
0	0	0	1365	0

		UTILITY DISTRICT-- 0	UTILITY DISTRICT-- 0	UTILITY DISTRICT-- 0	UTILITY DISTRICT-- 1036	UTILITY DISTRICT-- 0
UTILITIES BOARD-- 0	UTILITIES BOARD-- 1439					
		UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 1439	UTILITIES BOARD-- 0
COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 2218					
		COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 2218	COOKEVILLE GAS DEPT CITY OF-- 0
ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 1371	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTR-- 0	ELK RIVER PUBLIC UTILITY DISTRICT-- 1371	ELK RIVER PUBLIC UTILITY DISTRICT-- 0
ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 183					
		ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 183	ETOWAH UTILITIES DEPARTMENT-- 0
FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 690	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 690	FAYETTEVILLE GAS SYSTEM-- 0
GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 3035	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 3035	GALLATIN NATURAL GAS SYSTEM-- 0

COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 4126	COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 4126	COUNTY UTILITY DISTRICT-- 0
		COUNTY UTILITY DISTRICT-- 0				
UTILITIES BOARD-- 0	UTILITIES BOARD-- 35020	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 35020	UTILITIES BOARD-- 0
UTILITIES BOARD-- 0	UTILITIES BOARD-- 510					
		UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 510	UTILITIES BOARD-- 0
GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1075					
		GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1075	GAS DEPARTMENT-- 0
LOUDON UTILITIES GAS DEPARTMENT-- 0	LOUDON UTILITIES GAS DEPARTMENT-- 730	LOUDON UTILITIES GAS DEPARTMENT-- 0	LOUDON UTILITIES GAS DEPARTMENT-- 0	LOUDON UTILITIES GAS DEPARTMENT-- 0	LOUDON UTILITIES GAS DEPARTMENT-- 730	LOUDON UTILITIES GAS DEPARTMENT-- 0
SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 824					
		SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 824	SOUTH PITTSBURG CITY OF-- 0

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 25450	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 25450	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0

CLINCH UTILITY DISTRICT-- 0	CLINCH UTILITY DISTRICT-- 2160		CLINCH UTILITY DISTRICT-- 0	CLINCH UTILITY DISTRICT-- 0	CLINCH UTILITY DISTRICT-- 2160	CLINCH UTILITY DISTRICT-- 0

COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--

JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 309	JAMESTOWN NATURAL GAS SYSTEM-- 0

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0						
	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0

CKE COUNTY
UTILITY
DISTRICT--
0

CKE COUNTY UTILITY DISTRICT-- 804	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 804	CKE COUNTY UTILITY DISTRICT-- 0

COOKEVILLE
GAS DEPT CITY
OF--
0

COOKEVILLE GAS DEPT CITY OF-- 875	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 875	COOKEVILLE GAS DEPT CITY OF-- 0

200707 200710 200801

ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 0	ATMOS ENERGY CORPORATION-- 52633

UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 1000

GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1000

UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 19498

CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 1365



UTILITY DISTRICT-- 0	UTILITY DISTRICT-- 0	UTILITY DISTRICT-- 1036

UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 1439

COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 2218

ELK RIVER PUBLIC UTILITY DISTRICT-- 0	ELK RIVER PUBLIC UTILITY DISTRICT-- 0	ELK RIVER PUBLIC UTILITY DISTRICT-- 1371

ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 0	ETOWAH UTILITIES DEPARTMENT-- 183

FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 0	FAYETTEVILLE GAS SYSTEM-- 690

GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 0	GALLATIN NATURAL GAS SYSTEM-- 3035

COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 0	COUNTY UTILITY DISTRICT-- 4126

UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 35020

UTILITIES BOARD-- 0	UTILITIES BOARD-- 0	UTILITIES BOARD-- 510

GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 0	GAS DEPARTMENT-- 1075

LOUDON UTILITIES GAS DEPARTMEN-- 0	LOUDON UTILITIES GAS DEPARTMEN-- 0	LOUDON UTILITIES GAS DEPARTMEN-- 730

SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 0	SOUTH PITTSBURG CITY OF-- 824

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 25450

CLINCH UTILITY DISTRICT-- 0	CLINCH UTILITY DISTRICT-- 0	CLINCH UTILITY DISTRICT-- 2160

COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--	COUNTY UTILITY DISTRICT--

JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 0	JAMESTOWN NATURAL GAS SYSTEM-- 309

TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 0	TENNESSEE NATURAL GAS UTILITY DISTRICT-- 1193

CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 0	CKE COUNTY UTILITY DISTRICT-- 804

COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 0	COOKEVILLE GAS DEPT CITY OF-- 875

YYYYMM ➡	200Q10	200101	200104	200107	200110	200201
Total Seasonal Delivery						107,785
ET Contract						
30777	1	36,547	0	0	0	36,547
30777R1						
30777R2						
34798		1,000	1,000	1,000	1,000	1,000
34798R1						
34798R2						
34800		1,000	1,000	1,000	1,000	1,000
34800R1						
34800R2						
410044					5,751	0
410119						
410119R1						
410150						
410150R1						
410164						
410164R1						
410164R2						
410244R1						
4331	1	1,122	1,122	1,122	1,122	1,122
4331R1						
4331R2						
4335	1	1,341	1,341	1,341	1,341	1,341
4335R1						
4335R2						
4336	1	1,030	1,030	1,030	1,030	1,030
4336R1						
4337	1	134	134	134	134	134
4337R1						
4337R2						
4338	1	485	485	485	485	485
4338R1						

4340		2,060	2,060	2,060	2,060	
4340R1						
4341		2,837	2,837	2,837	2,837	2,837
4341R1						
4341R2						
4342	1	35,020	35,020	35,020	35,020	35,020
4342R1						
4343	1	397	397	397	397	397
4343R1						
4343R2						
4344	1	699	699	699	699	699
4344R1						
4344R2						
4347	1	438	438	438	438	438
4347R1						
4348	1	580	580	580	580	580
4348R1						
4348R2						
4349	1	16,621	16,621	16,621	16,621	16,621
4349R1						
4350	1	2,160	2,160	2,160	2,160	2,160
4350R1						
4350R2						
4351	1	1,133	1,133	1,133	1,133	1,133
4351R1						
4358	1	309	309	309	309	309
4358R1						
7566		1,193				1,193
7566R1						
7566R2						
7568	1	804	804	804	804	804
7568R1						
7568R2						
7570	1	875	875	875	875	875
7570R1						
7570R2						
						107,785

200204	200207	200210	200301	200304	200307	200310
74,989	73,796	5,751	107,785	68,814	5,751	5,751

0	0	0	36,547	0	0	0

0	0	0	1,000	0	0	0

0	0	0	1,000	0	0	0

5,751	5,751	5,751	0	5,751	5,751	5,751

1,122	1,122	0	1,122	0	0	0

1,341	1,341	0	1,341	0	0	0

1,030	1,030	0	1,030	1,030	0	0

134	134	0	134	0	0	0

485	485	0	485	485	0	0

2,060	2,060	0	2,060	2,060	0	0
2,837	2,837	0	2,837	2,837	0	0
35,020	35,020	0	35,020	35,020	0	0
397	397	0	397	0	0	0
699	699	0	699	699	0	0
438	438	0	438	438	0	0
580	580	0	580	580	0	0
16,621	16,621	0	16,621	16,621	0	0
2,160	2,160	0	2,160	2,160	0	0
1,133	1,133	0	1,133	1,133	0	0
309	309	0	309	0	0	0
1,193	0	0	1,193		0	0
804	804	0	804	0	0	0
875	875	0	875		0	0
74,989	73,796	5,751	107,785	68,814	5,751	5,751

200401	200404	200407	200410	200501	200504	200507
159,372	11,715	10,036	10,036	163,657	5,751	5,751

52,633	0	0	0	52,633	0	0

1,000	0	0		1,000	0	

1,000	0	0	0	1,000	0	0

0	5,751	5,751	5,751	0	5,751	5,751
19,498	0	0	0	19,498	0	0

4,285	4,285	4,285	4,285	4,285	0	0

1,365	0	0

1,439	0	0	0	1,439	0

2,218		0	0	2,218	

1,371	0	0	0	1,371	0

183	0	0	0	183	0

690	0	0	0	690	

3,035	0	0	0	3,035	0	0
4,126			0	4,126	0	0
35,020	0	0	0	35,020	0	0
510	0	0	0	510	0	0
1,075	0	0	0	1,075	0	0
730	0	0	0	730	0	0
824	0	0	0	824	0	0
25,450	0	0	0	25,450	0	0
3,525	0	0		2,160	0	0
1,864	0	0	0	1,864	0	0
309	0	0	0	309	0	0
1,193	0	0	0	1,193	0	0
804	804	0	0	804	0	0
875	875	0	0	875	0	0
159,372	11,715	10,036	10,036	163,657	5,751	5,751

200510	200601	200604	200607	200610	200701	200704
0	159,372	0	0	0	160,408	0
0	52,633	0	0	0	52,633	0
0	1,000	0	0	0	1,000	0
0	1,000	0	0	0	1,000	0
0	19,498	0	0	0	19,498	0
0	0					
0	1,365	0	0	0	1,365	0
		0	0	0	1,036	0
0	1,439	0	0	0	1,439	0
0	2,218	0	0	0	2,218	0
0	1,371	0	0	0	1,371	0
0	183	0	0	0	183	0
0	690	0	0	0	690	0

0	3,035	0	0	0	3,035	0
0	4,126		0	0	4,126	0
		0				
0	35,020	0	0	0	35,020	0
0	510					
		0	0	0	510	0
0	1,075					
		0	0	0	1,075	0
0	730	0	0	0	730	0
0	824					
		0	0	0	824	0
0	25,450	0	0	0	25,450	0
0	2,160					
		0	0	0	2,160	0
0	1,864	0	0	0	1,864	0
0	309	0	0	0	309	0
0						
	1,193	0	0	0	1,193	0
0						
	804	0	0	0	804	0
0						
	875	0	0	0	875	0
0	159,372	0	0	0	160,408	0

200707	200710	200801
0	0	160,408

0	0	52,633

0	0	1,000

0	0	1,000

0	0	19,498

0	0	1,365

0	0	1,036

0	0	1,439

0	0	2,218

0	0	1,371

0	0	183

0	0	690

0	0	3,035
0	0	4,126
0	0	35,020
0	0	510
0	0	1,075
0	0	730
0	0	824
0	0	25,450
0	0	2,160
0	0	1,864
0	0	309
0	0	1,193
0	0	804
0	0	875
0	0	160,408

TRA DOCKET NUMBER 07-00224

EXHIBIT H

1
2
3 Reply to 26.
4

5 Although, the testimony describes the
6 illustration as "just one example", refer
7 to page 52 of Dr. Brown's testimony which
8 shows CGC moving its subscribed capacity
9 of approximately 26,000 dekatherms from
10 the CGC's delivery points to meter 59014,
11 which CGC described as an "(IT ONLY)
12 delivery point in AGL Service Territory"
13 in CGC's reply to CAPD discovery request
14 72.
15

16 Also, refer to page 42 of Dr. Brown's
17 testimony which shows non-CGC, firm
18 contracts for delivery of customer owned
19 gas ranging from 1500 dekatherms to 7500
20 dekatherms.
21

22 Both of these pages support Dr. Brown's example
23 at page 16 of his testimony that it may be
24 possible for CGC's overall transportation
25 capacity from ETNG to be reduced from 41,500 to
26 30,000 dekatherms and still meet the needs of
27 firm customers.