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February 3, 2006

VIA UPS OVERNIGHT

The Honorable Ron Jones
Chairman
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-0505

Re: Nashville Gas Company, A Division of Piedmont Natural Gas Company, Inc. – Docket No. 05-00165

Dear Chairman Jones:

Pursuant to the procedural schedule established in this proceeding and Tenn. Comp. R. and Reg. 1220-1-1-2-.11, Nashville Gas Company respectfully submits a copy of the Second Supplemental Responses of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., to the Consumer Advocate and Protection Division's Second Set of Discovery Requests.

Please accept these Supplemental Responses for filing and return a filed-stamped copy of this letter to me in the enclosed self-addressed and stamped envelope.

Thank you for your assistance with this matter If you have any questions regarding these comments you may reach me at the number shown above.

Sincerely,

James H. Jeffries IV

JHJ/bao

Enclosure

c: All Parties of Record

Research Triangle, NC
Charleston, SC

NASHVILLE GAS COMPANY
REVIEW OF NASHVILLE GAS COMPANY'S IPA
RELATING TO ASSET MANAGEMENT FEES
DOCKET NO. 05-00165
CONSUMER ADVOCATE AND PROTECTION DIVISION
SECOND SET OF DISCOVERY REQUESTS
January 3, 2006

DISCOVERY REOUEST NO. 3

In response to Discovery Request No. 10 of the Consumer Advocate's First Set of Discovery Requests, Nashville Gas Company stated that "[o]ther reasons justifying the inclusions of the asset management fees are set forth in the proceedings in which the asset management fees were approved." Please identify all proceedings in which Nashville Gas contends that the asset management fees were approved, including, but not limited to, the particular documents from such proceedings that demonstrate the approval of asset management fees.

SUPPLEMENTAL RESPONSE: Please see the attached additional documents filed in TRA Docket No. 96-00805.

11

REC'D TN. PUBLIC SERVICE COMM.
'96 APR 22 AM 9 36
OFFICE OF THE EXECUTIVE DIRECTOR

Before The
Tennessee Public Service Commission
Nashville, Tennessee

Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company to Establish a Performance Incentive Plan	Docket No. ______

Application For Approval Of Performance Incentive Plan

Pursuant to Tennessee Code Annotated, Section 65-2-102, Nashville Gas Company (Nashville), a division of Piedmont Natural Gas Company, Inc. (Piedmont) hereby respectfully requests the Commission to approve the tariff containing the performance incentive plan (Incentive Plan) filed with this application as Exhibit ___ (TES-2). In support of this request, Nashville respectfully shows the following:

I.

Identity of Applicant.

The full name and address of the Petitioner is:

Nashville Gas Company
655 Mainstream Drive
Nashville, TN 37228

II.

Service List.

The names and addresses of all persons to whom correspondence, petitions, interventions and other communications relative to this Application should be mailed are as follows:

John H. Maxheim
Chairman, President and Chief Executive Officer
Piedmont Natural Gas Company, Inc.
P.O. Box 33068
Charlotte, NC 28233

(Service List Continued on Next Page)

Bill R. Morris
Director of Rates
Piedmont Natural Gas Company, Inc.
P.O. Box 33068
Charlotte, NC 28233

Jerry W. Amos
Amos & Jeffries, LLP
P. O. Box 787
Greensboro, NC 27402

III.

Jurisdiction of Commission.

Piedmont is incorporated under the laws of the State of North Carolina and is engaged in the business of transporting, distributing and selling gas in the States of Tennessee, North Carolina and South Carolina. Piedmont is a public utility under the laws of Tennessee, and its public utility operations in Tennessee are subject to the jurisdiction of this Commission. Piedmont conducts its public utility business in Tennessee through its operating division, Nashville. Nashville maintains an office at 665 Mainstream Drive, Nashville, Tennessee. Nashville is engaged in the business of furnishing natural gas in Davidson County and in portions of Cheatham, Dickson, Robertson, Rutherford, Sumner, Trousdale, Williamson and Wilson Counties, Tennessee, and in certain incorporated towns therein.

IV.

Purpose of Application.

The purpose of this application is to seek approval of the Incentive Plan. As explained in more detail in the testimony and exhibits accompanying this application, the Incentive Plan will provide Nashville with incentives to acquire gas at the lowest reasonable cost consistent with a secure gas supply, eliminate the need for time consuming and costly prudence reviews, and reduce consumer gas rates.

V.

Effect on Existing Ratemaking Procedures

Under the Incentive Plan, Nashville will be permitted to increase or required to decrease the margin component of its rates to reflect its performance gains or losses. No other changes would be required in existing ratemaking procedures. Nashville's base rates and base margin would continue to be established in general rate case filings. Nashville would continue to recover its gas costs under the existing PGA procedures and its GSR costs under the existing approved procedures. Nashville would also continue to adjust its rates as permitted by the WNA procedures.

VI.

General Description of Incentive Plan.

As explained in more detail in the testimony and exhibits accompanying this application, the Incentive Plan is comprised of two interrelated components--a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's city gate commodity cost of gas is compared, and also addresses the recovery of gas supply reservation fees, the treatment of offsystem sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market offpeak unutilized transportation and storage capacity on pipelines in the secondary market.

VII.

General Description of the Gas Procurement Incentive Mechanism.

The Gas Procurement Incentive Mechanism establishes a monthly benchmark dollar amount to which Nashville's actual city gate commodity gas costs are compared. If the total commodity gas purchase costs for a given month vary from the benchmark dollar amount by more than one percent (the monthly deadband), the variance or excess from the one percent deadband will be considered incentive gains or losses. These incentive gains or losses will be shared on a 50/50 basis between the company and its ratepayers subject to an overall annual cap of $1.6 million on gains or losses for Nashville under the plan. The benchmark dollar amount is established by multiplying total actual purchase quantities each month by a monthly price index. The monthly price index is a composite price referencing monthly index prices published by *Inside FERC* weighted by location according to Nashville's firm capacity rights each month on upstream pipelines for gas supplies purchased by Nashville in the first-of-the-month market and transported under Nashville's firm transportation (FT) contracts, monthly index prices published by *Inside FERC* for spot supplies purchased in the first of the month market and delivered to the city gate using transportation arrangements other than Nashville's FT contracts, and the weighted average daily index prices published by *Gas Daily* for Nashville's daily spot purchases.

VIII.

Reservation Fees.

Nashville would continue to pass through reservation fees paid to gas suppliers on a dollar for dollar basis (with no profit or loss potential). With respect to new or replacement supply arrangements or price renegotiations under existing arrangements, Nashville would solicit bids or proposals for service and choose the best bid for the firm service Nashville requires consistent with its "best cost" gas procurement strategy. Nashville would continue to reserve the right to offer existing suppliers (who have performed well under expiring contracts) a right of first refusal to match the best bid.

IX.

Offsystem Sales and Wholesale Sale for Resale Transactions.

Any margin generated as the result of offsystem sales or wholesale sale for resale transactions using Nashville's firm transportation or storage capacity entitlements (the costs of which are recovered from Nashville's ratepayers) will be credited to gas costs and will be shared with ratepayers under the Gas Procurement Incentive Mechanism. Margin will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is already taken into account under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

X.

Financial and Other Private Contracts.

To the extent Nashville uses futures contracts, other financial derivative products, storage swap arrangements or other private contractual arrangements to hedge, manage or reduce gas costs, it will flow through any gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

XI.

Capacity Management Incentive Mechanism.

The Capacity Management Incentive Mechanism is designed to provide Nashville an incentive to release unutilized offpeak firm transportation or storage capacity in the secondary interstate market and reduce Nashville's demand charges paid under those contracts to pipelines. The plan would flow back to Nashville's ratepayers 75% of the resulting cost savings and credit Nashville with 25% of the savings. Transportation or storage margin embedded in offsystem sales or wholesale interstate sale for resale transactions (as described above) will also be subject to the same 75/25 sharing formula. Like the other components of Nashville's incentive plan, the Capacity Management Incentive Mechanism will be subject to the $1.6 million overall annual cap on gains and losses for Nashville established for the plan.

XII.

New Pipeline Capacity Demand Costs and Gas Supply Reservation Fees.

New pipeline capacity demand costs and/or gas supply reservation fees will be recovered through the PGA on a dollar for dollar basis (with no profit or loss potential). Nashville will solicit bids and will choose the bid which best matches Nashville's requirements. As new firm transportation capacity or supply services are added to Nashville's portfolio, Nashville will amend the monthly price index formula set forth in the Gas Procurement Incentive Mechanism to take into account any new weighting of capacity entitlements within the supply zones.

XIII.

Cap on Gain and Losses.

Nashville will be limited to overall gains or losses totaling $1.6 million under the Incentive Plan in any plan year. Such gains or losses would form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve month period.

XIV.

Accounting Procedures.

Each month during the term of plan, Nashville will compute any gains or losses under the Incentive Plan. If Nashville earns a gain, a separate non-interest bearing Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefits from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

XV.

Reports.

Nashville will file interim quarterly reports of the IPA account with the Commission not later than 60 days following the end of each fiscal quarter and will file an annual report of IPA activity not later than 60 days following the end of each plan year.

XVI.

Proposed Effective Date.

Nashville requests an effective date of July 1, 1996, with the first plan year continuing through June 30, 1997. The plan would rollover into a second year commencing July 1, 1997 and ending June 30, 1998 with the agreement of Nashville and the approval of the Commission. Nashville would inform the Commission of its intention to roll over the plan for a second year no later than April 1, 1997.

XVII.

Attachments.

The following documents are being filed with and are incorporated herein:

1. Testimony and Exhibits of Thomas E. Skains;

2. Testimony and Exhibits of Chuck Fleenor; and

3. Testimony and Exhibits of Dr. Jay P. Lukens.

XVIII.

Request for Approval.

WHEREFORE, Nashville respectfully requests the Commission to (1) find that the proposed Incentive Plan is in the public interest and to grant authorization under Tennessee Code Annotated, Section 65-2-102, as amended, to implement the Incentive Plan effective July 1, 1996 on the terms and conditions set forth herein and in the Incentive Plan and (2) relieve Nashville of any responsibility for prudence reviews or their costs during the term of the Incentive Plan.

Nashville Gas Company, a Division of
Piedmont Natural Gas Company, Inc.

By: ______________________
John H. Maxheim, President,
Chairman of the Board and
Chief Executive Officer

____
Jerry W. Amos
Amos & Jeffries, L.L.P.
P.O. Box 787
Greensboro, NC 27402
Telephone: (910) 273-5569

STATE OF NORTH CAROLINA)

)

COUNTY OF MECKLENBURG)

John H. Maxheim, being first duly sworn, states that he is President, Chairman of the Board and Chief Executive Officer of Piedmont Natural Gas Company, Inc., that he has read the foregoing Petition, that the facts stated therein are true to the best of his knowledge, information and belief and that he has been duly authorized to execute the foregoing Petition on behalf of Piedmont Natural Gas Company, Inc.

John H. Maxheim

John H. Maxheim

Sworn to and subscribed before me
this the 18th day of April, 1996

Melanie H. Emery

Notary Public

My commission expires:
May 26, 1998

Tennessee Public Service Commission
Docket No. _________

Direct Testimony of Thomas E. Skains

on Behalf of

Nashville Gas Company,
a Division of
Piedmont Natural Gas Company, Inc.

Piedmont
Natural Gas
Company

I. Identification of Witness.

Q. Please state your name and your business address.

A. My name is Thomas E. Skains. My business address is 1915 Rexford Road, Charlotte, North Carolina 28211.

Q. By whom and in what capacity are you employed?

A. I am employed by Piedmont Natural Gas Company, Inc., (Piedmont) as Senior Vice President, Gas Supply and Services.

Q. Please describe the scope of your present responsibilities for Piedmont?

A. My principle duties are to direct the activities of the company in areas related to the planning, procurement and utilization of pipeline capacity and gas supplies to meet Piedmont's present and future requirements, including the requirements of Piedmont's Nashville Gas Company division (Nashville). In addition, I am responsible for Piedmont's sales and transportation services and the management of the company's throughput, including industrial customer services and gas control operations.

Q. Please describe your educational background?

A. I graduated from Sam Houston State University in 1978 with a Bachelor's Degree in Business Administration. In 1981, I received a Doctor of Jurisprudence Degree from the University of Houston Law School, and I was admitted to the State Bar of Texas.

Q. Please describe your professional background.

A. I joined the legal department of Transcontinental Gas Pipe Line Corporation (Transco) in 1981, and I practiced law in the areas of gas supply, rate and federal regulatory matters until 1986. In 1986, I was elected a Vice President of Transco and was responsible for marketing, transportation and customer services. I was promoted to Senior Vice President of Transco in 1989, and I was responsible for the marketing and administration of Transco's transportation and storage services, including project development activities, until I left Transco in April 1995 to join Piedmont.

Q. Have you previously testified before any regulatory authority?

A. Yes. I have presented testimony and appeared as a witness in numerous proceedings before the Federal Energy Regulatory Commission (FERC), and I have appeared before the North Carolina Utilities Commission (NCUC).

II. Identification of Applicant.

Q. Please give a general description of Piedmont and its businesses.

A. Piedmont is a North Carolina corporation with its corporate headquarters in Charlotte, North Carolina. Piedmont is principally engaged in the natural gas distribution business and as of February 1996 delivered gas to approximately 538,000 customers---119,000 of which are located in Tennessee. Our Tennessee operations are conducted by our Nashville division. Of total fiscal year 1995 (ending October 31, 1995) natural gas deliveries of 125,593,326 dts, 27,891,656 dts or 22% were delivered to customers of Nashville.

III. Purpose of Testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain Nashville's goals in this proceeding and to describe Nashville's proposed performance incentive plan relating to its gas acquisition activities. I am also sponsoring Nashville's application in this proceeding and certain exhibits.

Q. Will other witnesses offer testimony on Nashville's behalf?

A. Yes. Dr. Jay Lukens will offer testimony on the appropriate goals for a performance incentive plan, describe the attributes of a good incentive plan and describe how Nashville's plan meets these goals. Mr. Chuck Fleenor will describe Nashville's design day requirements and the company's three year supply plan to meet those requirements through the winter of 1998-1999.

Q. Have you reviewed the application filed by Nashville in this proceeding?

A. Yes.

Q. To the best of your knowledge and belief are the statements contained in that application true and correct?

A. Yes.

Q. What exhibits are your sponsoring?

A. I am sponsoring Exhibit ___ (TES-1) which is a description of the proposed performance incentive plan, Exhibit ___ (TES-2) which is the tariff under which the proposed performance incentive plan will be implemented, Exhibit ___ (TES-3) which is a schedule summarizing Nashville's existing firm transportation and storage capacity arrangements on pipelines, and Exhibit ___ (TES-4) which is a schedule summarizing Nashville's firm gas supply arrangements with producers and marketers.

IV. Current ratemaking procedures.

Q. Please explain the current procedures under which Nashville's rates are set by this Commission.

A. Nashville's rates are established by this Commission in general rate cases. The rates established by the Commission in those cases, however, are subject to adjustment under various orders, rules, and regulations of the Commission. For example, Nashville's rates are adjusted upward or downward under the Commission's Purchased Gas Adjustment (PGA) rules to reflect changes in the wholesale cost of gas. Nashville's rates are also subject to adjustment for changes in the weather under Nashville's Weather Normalization Adjustment (WNA) procedures approved by the Commission in Docket No. 91-01712. Finally, Nashville's rates are subject to adjustment from time to time under procedures approved by the Commission in Docket No. 94-04284 which permit Nashville to recover certain FERC Order No. 636 gas supply realignment (GSR) costs passed on to it by upstream pipelines.

Q. What, if any, problems exist under the existing method for setting rates?

A. The current ratemaking procedures were adopted at a time when utilities, at least in theory, were regulated monopoly franchises protected from competition. A utility's earnings are limited to a return on its plant investment determined to be "just and reasonable." Rates are set at a level that will give the utility an opportunity to recover its prudently incurred costs (including gas costs) and to earn a fair return. There are no specific "incentive" programs or "carrots" to reward a utility for improved performance. Instead, the procedures rely on a disincentive or a "stick" that a utility will be penalized and costs disallowed if it is found imprudent.

Q. Doesn't Nashville's statutory obligation to operate in the most efficient, least-cost manner provide incentive enough for efficient operations?

A. While I certainly believe that Nashville has conducted its business affairs prudently under the current regulatory regime, I do fundamentally believe that "carrot" as opposed to "stick" regulation provides a better approach to improving business performance. This question was answered by Commissioner Terrence L. Bernice of the Illinois Commerce Commission as follows:

> "There are those...who cling to the maxim that regulated utilities already have the statutory obligation to operate in the most efficient, least-cost manner and coupled with the retention of 'excess' earnings attributable to regulatory lag, there is a duty and incentive enough for efficient operations without the need for new-fangled incentive plans. I would have thought that argument would have gone the way of the Berlin Wall, which was demolished by the power of the truth now assaulting traditional regulation: Regimes founded upon profit incentives induce people to act more efficiently (and thus more prosperously) than regimes propped up by the bludgeon of command and control regulation."
>
> *Public Utilities Fortnightly,* June 15, 1995, p.16.

Q. Why did you state that utilities have been historically protected from competition "in theory?"

A. Local distribution companies have never been truly protected from competition from alternative fuels, such as residual fuel oil, propane, coal, electricity and wood chips. It is true that prior to the changes in the natural gas industry resulting from FERC Order Nos. 436 and 636, local distribution companies faced little competition regarding the acquisition and sale of interstate gas supplies and pipeline capacity. Today, however, with "open access" transportation and the deregulation of gas supplies, many large price sensitive customers can arrange pipeline capacity and buy gas from diverse pipeline and supply sources. To compete, utilities must be more innovative and must take more risks than ever before. Nashville is willing to undertake these additional risks; however, we believe we should also be permitted to share in the rewards when our performance improves. Nashville's proposed performance incentive plan is designed to provide prospective incentives for improved performance by the company in its gas acquisition activities in a manner that we believe would produce provides an opportunity for rewards for both our customers and our shareholders.

Q. Could Nashville be provided adequate incentives through the elimination of PGA procedures?

A. No. Roughly 50% of Nashville's fiscal year 1995 revenues consisted of gas cost recovery. This compares to only 7% of Nashville's revenues that represented profits. Thus, a very small change in Nashville's cost of gas could totally eliminate Nashville's profits. Since gas prices change on a daily basis depending upon weather and a number of other factors beyond our control, we could lose substantial sums of money or earn windfall unreasonable profits due solely to fluctuations in gas prices over which we have no control. We do not believe this result would be fair either to our customers or to our shareholders. In the absence of PGA procedures, the only way to limit these losses in a regulated environment would be to file general rate cases (including gas costs) on at least a monthly basis. Not only would these rate cases be extremely costly and time-consuming for all parties, they would produce an instability that would make it difficult, if not impossible, for Piedmont to raise capital on terms that were fair and reasonable.

Q. Is Nashville proposing to amend the PGA procedures in this docket?

A. No. The method by which rates are established under the PGA procedures would not be affected in any manner by adoption of the proposed performance incentive plan. But because our performance relative to pipeline capacity and gas supply acquisition costs will be measured, rewarded and/or penalized under the proposed performance incentive plan, gas cost prudence reviews or audits will no longer be required.

V. Background

Q. Would you please provide an overview of Nashville's gas procurement strategy?

A. Several years ago, the company adopted a "best cost" gas purchasing policy. This policy consists of five main components -- the price of gas, the security of the gas supply, the flexibility of the gas supply, gas deliverability and supplier relations. All of these components are interrelated, and we consider and weigh each of these factors when developing an overall gas supply portfolio. We place a value on supply security to meet the requirement of our firm customers; therefore, we acquire firm transportation and storage capacity from pipelines and firm gas supply arrangements from producers and marketers. These firm contract rights generally require the payment of demand charges and/or reservation fees to secure firm warranted service. Overall, we believe our "best cost" purchasing policy provides Nashville with a secure, reasonably priced supply of gas to meet the requirements of our customers.

Q. Please describe Nashville's firm pipeline transportation arrangements.

A. As a result of FERC Order Nos. 436 and 636, Nashville has unbundled its services on pipelines. Exhibit ___ (TES-3) summarizes Nashville's existing firm transportation and storage capacity arrangements. Under these service agreements, Nashville pays demand and commodity charges that are found just and reasonable by the FERC. As reflected on that schedule, Nashville holds 136,677 dt/d of peak day firm transportation capacity from the supply area to Nashville's city gates. 130,000 dt/d of that capacity is 365-day firm transportation service under Tennessee Gas Pipeline Company's (Tennessee) Rate Schedule FT-A. Of such amount, 107,565 dt/d extends back to Tennessee's Zone 1 (Southern Zone through Louisiana) and 22,435 dt/d back to Tennessee's Zone 0 (Texas Zone). On Columbia Gulf Transmission (CGT), Nashville holds 5,000 dt/d of October through March firm transportation capacity (4,601 dt/dt April through September) under Rate Schedule FTS1 extending back to Rayne, Louisiana. Nashville also subscribes to 1,677 dt/d of 365-day firm transportation capacity on Texas Eastern Transmission (Tetco) under Rate Schedule SCT in Zone M1.

Q. What about Nashville's firm storage arrangements?

A. Nashville has subscribed to a total of 4,385,904 dt of firm storage capacity with 85,900 dt/d of associated peak day withdrawal deliverability. On Columbia Gas Transmission (TCO), Nashville holds 611,870 dt of market area storage under Rate Schedule FSS with 10,000 dt/d of peak day withdrawal deliverability. Nashville has also contracted with TCO for 10,000 dt/d of associated firm transportation capacity under Rate Schedule SST (5,000 dt/d for summer injections) to provide incremental peak day service for storage withdrawals to the city gate. On Tennessee, Nashville has subscribed to 2,901,943 dt of market area storage capacity with 49,828 dt/d of associated peak day withdrawal deliverability under Rate Schedule FS-MA, and 672,091 dt of production area storage capacity with 6,072 dt/d of associated peak day withdrawal deliverability under Rate Schedule FS-PA. Storage injections and withdrawals are transported under Nashville's FT-A service arrangement with Tennessee described above. Finally, Nashville is allocated 200,000 dt of firm storage capacity and 20,000 dt/d of withdrawal deliverability under a contract with Crystal Oil Company at the Hattiesburg salt dome facility in Mississippi. Like Tennessee storage, Hattiesburg storage withdrawals are transported to Nashville's city gate using Tennessee FT-A capacity or other incremental arrangements on the Tennessee system.

Q. Mr. Skains, Could you please describe Nashville's firm existing gas supply arrangements on the Tennessee system?

A. Exhibit ___ (TES-4) summarizes Nashville's firm gas supply arrangements with producers and marketers. In general, under these contracts, Nashville pays negotiated reservation fees for the right to reserve and call on firm warranted supply service up to the maximum daily contract quantity, and market-based commodity charges tied to first-of-the-month index prices published in *Inside FERC* (an industry trade publication) for the dekatherms actually purchased each month.

On Tennessee's pipeline system, Nashville has contracted for firm gas supplies with six suppliers under eight contracts. Six of these contracts, which total 44,000 dt/d of supply service are for winter only service

(November - March) and provide for monthly nominate/baseload type service. Under these contracts, Nashville has the right to nominate in advance of each month all or any part of the daily contract quantity and must take and purchase (i.e., baseload) each day of that month the daily quantity so nominated. Nashville has no right to call on or purchase during any such month any portion of the daily contract quantity not nominated for purchase on a monthly basis in advance.

In addition, Nashville has one firm supply contract for 30,100 dt/d on the Tennessee system which provides for 365 day service. During the summer months (April through October), the entire contract quantity is a monthly nominate/baseload service and during the winter months (November through March) 15,000 dt/d is monthly nominate/baseload service and 15,100 dt/d is daily swing service. Under daily swing service, Nashville has the right to nominate in advance of each day all or any part of the daily contract quantity and must take and purchase the daily quantity so nominated. Nashville has no right to call on or purchase any portion of the daily contract quantity not nominated for purchase on a daily basis in advance.

Q. Could you please describe the commodity pricing provisions in these gas purchase agreements?

A. Under the firm gas supply contracts on the Tennessee system, the commodity sales index price is established each month by reference to the first-of-the-month index price published by *Inside FERC* for the geographic location to which Nashville's firm capacity rights extend (either Zones 0 or 1).

Q. What are the remaining terms of these supply contracts.

A. With the exception of two contracts, the gas supply arrangements on Tennessee described above extend until March 31, 2000. The remaining two contracts expire or may be terminated in 1997.

Q. Could you please describe Nashville's firm gas supply arrangement on the CGT system?

A. On the CGT system, Nashville has contracted for firm gas supplies with one supplier for a daily swing contract quantity of up to 5,000 dt/d on a 365-day basis, provided such quantity is nominated prior to the first of each month. The commodity sales index price is established each month by reference to the first-of-the-month index price published by *Inside FERC* for CGT, Louisiana plus the applicable transport charges and fuel in CGT's FT tariff for transport to Rayne. This contract may be terminated by written notice effective as of October 31, 1997.

Q. What about arrangements on the Tetco system serving Nashville's Hartsville system?

A. On the Tetco system, Nashville has assigned a supplier agency rights to its Tetco SCT firm transportation capacity, and Nashville has purchased a bundled 365-day city gate swing supply service from that supplier. This small contract (0.5% of Nashville's fiscal year 1995 gas supply) serves Nashville's requirements for the Hartsville area and is designed to replicate the small bundled full service contract Nashville formerly held on Tetco. No reservation fees are paid on a fixed basis and Nashville pays a fixed commodity rate per dt for city gate quantities actually taken each day. This bundled service allows for intra-day swing service to meet Hartsville's day-to-day requirements. This contract may be terminated by written notice effective as of April 30, 2002 and provides for annual price renegotiations.

Q. Is there any other general information you would like to provide concerning Nashville's supply arrangements?

A. In addition to the first-of-the-month commodity-priced firm supply contracts described above, Nashville may enter the spot market from time to time to supplement its supply arrangements. Such purchases are made to augment Nashville's storage withdrawals and firm supply purchases, to balance supply and demand and to avoid reservation fees which would otherwise be paid for firm offpeak supply arrangements. These daily or monthly spot supply purchases may be purchased at the city gate or transported under Nashville's firm or interruptible transportation arrangements with the upstream pipelines.

During fiscal year 1995, all of Nashville's first of the month supply purchases were transported under FT capacity arrangements to the city gate. Of Nashville's fiscal year 1995 gas supply, less than one percent represented daily spot purchases and all of such purchases were transported to Nashville's city gates under its FT service agreements with the upstream pipelines.

Q. Will Nashville need to acquire additional firm capacity and supply during the term of the proposed performance incentive plan?

A. Yes. As explained by Mr. Fleenor, Nashville is experiencing design day growth in its market area. Nashville will be in the market for supplemental firm gas supply arrangements to meet those requirements. Consistent with its past practice, Nashville will solicit bids and proposals for these incremental firm services and choose the bid which best matches Nashville's requirements consistent with Nashville's "best cost" supply philosophy. Of course, Nashville will need to take into account operational limitations and supply diversity factors in this bidding process. In addition, although outside the term of the proposed incentive performance plan, Nashville's existing firm service agreements with Tennessee will terminate effective November 1, 2000, and those agreements will be subject to renegotiation, termination and/or replacement at that time.

VI. The proposed performance incentive plan.

Q. What are Nashville's primary goals in this proceeding?

A. Nashville has three primary goals in submitting the instant performance incentive plan for approval. First, Nashville would like to obtain advance Commission approval for a gas procurement plan that will enable it to serve the present needs of its customers and the anticipated load growth on its system in the most efficient, cost-effective manner possible while ensuring secure and reliable service. The establishment and approval of a clear, well-organized gas supply plan will enable Nashville to align its resources and strategies to meet these objectives. Second, the adoption of the proposed plan will avoid the necessity of hindsight prudence reviews. These review procedures, while understandable in the context of the old regulatory regime, are a time consuming and expensive drain on the resources of Nashville and the Commission. More productive results could be achieved by constructively focusing on the present and future. Finally, Nashville's incentive plan creates opportunities for the company while at the same time reducing gas costs for the benefit of its customers through prospective improvements in the company's gas acquisition performance. Nashville continually strives to create "win-win" business arrangements and believes the profit sharing methodologies set out in its incentive plan provide just that -- an opportunity for the company and its customers to share the benefits of improvements in Nashville's gas procurement activities.

Q. What advantages does the proposed incentive plan provide for the Commission, its staff, and interested intervenors?

A. One of the major problems with traditional ratemaking procedures is that they are often adversarial and rigid as the result of the legal requirements imposed by due process. Instead of working together to achieve *future* savings through increased efficiencies, parties spent vast resources reviewing *past* expenses. Under the proposed incentive rate plan, all parties will share the same goals. If Nashville can reduce its gas costs, all will benefit; therefore, there will be an incentive to work together to achieve future savings rather than discuss the past.

Q. Explain how Nashville's rates would be established by the Commission under the proposed incentive rate plan.

A. Nashville's base rates and base margin would continue to be established in general rate case filings. Nashville would continue to recover its gas costs under the existing PGA procedures and its GSR costs under the existing approved procedures. Nashville would also continue to adjust its rates as permitted by the WNA procedures where the customer would continue to be protected from weather variations. The only change in the existing ratemaking procedures is that Nashville would either increase or decrease the margin component of its rates to reflect its performance gains or losses under the performance incentive plan.

Q. Could you please describe the elements of Nashville's incentive proposal?

A. Nashville's performance incentive plan is comprised of two interrelated components--a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's city gate commodity cost of gas is compared, and also addresses the recovery of gas supply reservation fees, the treatment of offsystem sales and wholesale interstate sale for resale transactions and the use of financial or private contracts in managing gas costs. The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market offpeak unutilized transportation and storage capacity on upstream pipelines in the secondary market.

Q. Could you please describe the components of the Gas Procurement Incentive Mechanism in more detail?

A. The Gas Procurement Incentive Mechanism establishes a monthly benchmark dollar amount to which Nashville's actual city gate commodity gas costs are compared. The benchmark dollar amount is established by multiplying total actual purchase quantities each month by a monthly price index. The monthly price index is a composite per dt price referencing monthly index prices published by *Inside FERC* weighted by location according to Nashville's firm capacity rights each month on upstream pipelines for gas supplies purchased by Nashville in the first-of-the-month market and transported under Nashville's firm transportation (FT) contracts, monthly index prices published by *Inside FERC* for spot supplies purchased in the first of the month market and delivered to the city gate under arrangements other than Nashville's FT contracts, and the weighted average daily index prices published by *Gas Daily* for Nashville's daily spot purchases.

Q. How does the monthly price index provide Nashville an opportunity to improve its performance?

A. As reflected on Exhibit ___ (TES-4) and described earlier in my testimony, the *Inside FERC* first-of-the-month index prices used in the monthly index price formula are the same index prices referenced by Nashville's existing firm gas supply contracts. In addition, the monthly price index is weighted using Nashville's existing pipeline FT capacity entitlements. As a result, Nashville must take proactive steps to achieve improved performance in its gas acquisition activities under these contracts in order to reduce gas costs and earn incentive gains under the plan.

Under our proposal, Nashville has the opportunity to improve its performance by optimizing its first-of-the-month gas purchases through its existing FT capacity entitlements on upstream pipelines (currently during peak winter months 22,435 dt/d in Tennessee Zone 0, 107,505 dt/d in Tennessee Zone 1 and 5,000 dt/d at CGT Rayne) to achieve the lowest possible price. The specific optimization strategy that Nashville will employ each month will depend on the dynamics of changing regional and locational pricing in the gas market. In addition, Nashville has the opportunity to negotiate first-of-the-month prices which beat the published *Inside FERC* index prices and day market prices (daily spot purchases) which beat the average daily market price for similar daily transactions as published in *Gas Daily*.

Q. Is the small supply contract on the Tetco system taken into account in the monthly price index formula?

A. No. Because of the small size and low load factor utilization of that arrangement at the present time and the complexities associated with the bundled city gate structure of that supply arrangement (with the reservation fee and pipeline demand charges embedded in the gas commodity price), we have not included a weighting in the monthly index formula to account for that contract. We propose to pass through all costs associated with this supply contract on a dollar-for-dollar basis (with no profit or loss potential) as we do today under the PGA. Any extension or replacement of such contract would be subject to the same competitive bidding procedures as Nashville's firm reservation fee contracts described below.

Q. How does the Gas Procurement Incentive Mechanism provide Nashville incentives related to its commodity gas purchasing practices?

A. If the total commodity gas purchase costs for a given month vary from the benchmark dollar amount by more than one percent (the monthly deadband), then the variance or excess from the one percent deadband shall be considered incentive gains or losses. These incentive gains or losses will be shared on a 50/50 basis between the company and its ratepayers subject to an overall annual cap on gains or losses under the incentive plan to be discussed later in my testimony.

Q. What is the rationale for a monthly one percent deadband under which all gains or losses are passed through to the ratepayers?

A. The deadband provides some allowance for uncertainty and unexpected change in market conditions in today's dynamic and volatile gas market. The deadband is smaller than those approved in other incentive plans due to the fact that Nashville is proposing to pass through supplier reservation fees on a dollar-for-dollar basis (with no profit or loss potential) as described below. As a result, the deadband does not need to be widened to take into account the premium paid for firm gas supplies since the plan accounts for that premium separately.

Q. You mentioned reservation fees to gas suppliers, how does Nashville address these costs in its plan?

A. Because of the importance placed by Nashville on security and reliability of firm service, Nashville would continue to pass through these costs on a dollar-for-dollar basis (with no profit or loss potential). Otherwise, Nashville may be placed in an awkward position of possibly maximizing profit potential by reducing its firm supply entitlements and taking the risk on supply security or facing financial losses by paying reservation fees to ensure supply security and reliability in a market of rising reservation fees for firm supply.

With respect to new or replacement supply arrangements or price renegotiations under existing arrangements, Nashville would solicit bids for service and choose the best bid consistent with Nashville's "best cost" supply philosophy for the firm service Nashville requires. Nashville would continue to reserve the right to offer existing suppliers (who have performed well under expiring contracts) a right of first refusal to match the best bid.

Q. How will Nashville account for any margin created by offsystem sales or wholesale interstate sales using Nashville's firm storage or pipeline capacity entitlements?

A. Any margin created by offsystem sales or wholesale sale for resale transactions using Nashville's firm transportation or storage capacity entitlements (the costs of which are recovered from Nashville's ratepayers) will be credited to gas costs and under our proposal will be shared with ratepayers under the Gas Procurement Incentive Mechanism. Margin will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as applicable, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism described later in my testimony. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared equally with ratepayers.

Q. Does Nashville's Gas Procurement Incentive Mechanism or other specific formula features of Nashville's incentive plan explicitly address use of financial instruments or other contract mechanisms to control, hedge or otherwise reduce gas costs?

A. To the extent Nashville uses futures contracts or other financial derivative products to hedge or manage gas costs or storage swap arrangements or other contractual arrangements to reduce gas costs, it will flow through any gains or losses through the commodity cost component of the Gas

Procurement Incentive Mechanism. Private negotiated arrangements with third parties may be particularly useful in managing and optimizing the value of Nashville's storage assets.

Q. Mr. Skains, could you explain how firm pipeline transportation and storage costs are treated under the plan?

A. As explained earlier in my testimony, the demand and commodity charges incurred by Nashville under its transportation and storage contract with pipelines are subject to regulation by the FERC and are found to be "just and reasonable" under Natural Gas Act (NGA) rate case approval procedures. Nashville treats these costs as gas costs for purposes of flow through under its PGA and would continue to do the same under the plan.

Q. Could you please describe the second component of Nashville's incentive performance plan -- the Capacity Management Incentive Mechanism?

A. The Capacity Management Incentive Mechanism is designed to provide Nashville an incentive to release unutilized offpeak firm transportation or storage capacity in the secondary interstate market and reduce Nashville's demand charges paid under those contracts to pipelines. The plan would flow back to Nashville's ratepayers 75% of the resulting cost savings and credit Nashville with 25% of the savings. Transportation or storage margin embedded in offsystem sales or wholesale interstate sale for resale transactions (as described earlier in my testimony) will also be subject to the same 75/25 sharing formula. Like the other components of Nashville's incentive plan, the Capacity Management Incentive Mechanism will be subject to the annual cap on gains and losses established for the plan as discussed below.

Q. Does Piedmont have a similar 75/25 sharing mechanism in effect in any other jurisdiction?

A. Yes. A similar 75/25 sharing arrangement has been approved by the North Carolina Utilities Commission.

Q. Mr. Fleenor testifies to the need for Nashville to acquire incremental firm supply service during the term of the plan to meet Nashville design day growth requirements and to establish a reserve margin. How will any new capacity or supply costs be treated under the proposed incentive plan?

A. Like the treatment of renegotiated firm supply reservation contracts, Nashville would propose to flow through new pipeline capacity demand costs and gas supply reservation fees on a dollar-for-dollar basis (with no profit or loss potential). As described earlier in my testimony, Nashville will solicit bids and will choose the bid which best matches Nashville's requirements. As new firm transportation capacity or supply services are added to Nashville's portfolio, Nashville would need to modify the monthly price index formula set forth in the Gas Procurement Incentive Mechanism to take into account any new weighting of capacity entitlements within the supply zones.

Q. Could you please describe the overall annual cap on incentive gains and losses you have mentioned earlier in your testimony?

A. During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate non-interest bearing Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available. Total incentive plan performance gains or losses for any plan year will be limited to $1.6 million.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefits from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

Nashville will file interim quarterly reports of the IPA account with the Commission not later than 60 days following the end of each fiscal quarter and will file an annual report of IPA activity not later than 60 days following the end of each plan year.

Q. What is the rationale for an overall cap on gains and losses, in general, and the $1.6 million cap for Nashville, to be specific?

A. Overall caps on gains and losses associated with incentive programs are generally approved to ensure that the utility does not achieve unreasonable profits or suffer catastrophic losses under an incentive plan which is essentially experimental in nature. The $1.6 million cap for Nashville provides a meaningful incentive for proactive performance

Q. When does Nashville propose to place its incentive performance plan into effect?

A. Nashville requests an effective date of July 1, 1996, with the first plan year continuing through June 30, 1997. The plan would rollover into a second year commencing July 1, 1997 and ending June 30, 1998 with the agreement of Nashville and the approval of the Commission. Nashville would inform the Commission of its intention to roll over the plan for a second year no later than April 1, 1997.

Q. Mr. Skains, can you estimate how Nashville would have performed under the incentive plan during any recent test years?

A. Yes. During calendar year 1994 the plan would have generated losses of approximately $69,000 subject to 50/50 sharing under the Gas Procurement Incentive Mechanism and cost savings of approximately $546,000 subject to 25/75 sharing under the Capacity Cost Incentive Mechanism. These amounts compare to total commodity gas costs of $ 42.4 million and total pipeline capacity demand costs of $22.2 million in calendar year 1994. Nashville would have earned an incentive gain approximately of $102,000 and ratepayers would have recognized incentive savings of approximately $375,000.

During calendar year 1995, the plan would have generated losses of approximately $36,000 subject to 50/50 sharing under the Gas Procurement Incentive Mechanism and cost savings of approximately $530,000 subject to 25/75 sharing under the Capacity Cost Incentive

Mechanism. These amounts compare to total commodity gas costs of \$38.3 million and total pipeline capacity demand costs of \$18.7 million in calendar year 1995. Nashville would have earned an incentive gain of approximately \$116,000 and ratepayers would have recognized savings of approximately \$386,000.

Q. Mr. Skains, does this conclude your testimony?

A. Yes, it does.

Nashville Performance Incentive Plan

Introduction

Nashville Gas Company's (Nashville's) Performance Incentive Plan is comprised of two interrelated components--a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. In the first part, Nashville's commodity gas cost performance is compared to predefined benchmark indices. In the second part, Nashville is encouraged to actively market unutilized off-peak pipeline capacity in the secondary capacity release market.

Nashville requests an effective date of July 1, 1996, with the first plan year extending through June 30, 1997. The plan will continue into a second year with the agreement of Nashville and the approval of the Commission. Nashville will inform the Commission of its willingness to extend the Plan for a second year no later than April 1, 1997.

Gas Procurement Incentive Mechanism

<u>Commodity Costs</u>

Each month Nashville will compare its total city gate commodity cost of gas[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+...P_\infty K_\infty)+F_oO+F_dD; \text{ where}$$

$$F_f+F_o+F_d= 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

[1]Gas purchases under Nashville's supply contract on the Tetco system to serve Nashville's Hartsville system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TPG) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future. The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[2]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

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[2]Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

Gas Supply Reservation Fees

Nashville shall continue to recover 100 percent of gas supply reservation fees cost through its PGA with no profit or loss potential. For new contracts and contracts subject to renegotiation during the Plan year, Nashville shall solicit bids for gas supply reservation fees contracts.

Offsystem Sales and Sale for Resale Transactions

Margin on offsystem sales and wholesale sale-for-resale transactions using Nashville's firm transportation or storage entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to gas costs and will be shared with ratepayers under the commodity cost component of the incentive plan. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use of Financial Instruments or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

Capacity Management Incentive Mechanism

To the extent Nashville is able to release transportation or storage capacity in the secondary market, it will flow back to ratepayers 75 percent of associated cost savings and retain 25 percent of the cost savings. Transportation or storage margin (calculated as described above) associated with offsystem or wholesale sales will also flow through to ratepayers on a 75/25 sharing basis.

Cap on Incentive Gains and Losses

During a plan year, overall gains or losses for Nashville cannot exceed $1.6 million.

Three Year Supply Plan

As a part of the Performance Incentive Plan, Nashville is submitting a Three Year Supply Plan. Nashville will obtain additional firm gas supply related thereto. Included in the Supply Plan is support for a capacity reserve margin.

SERVICE SCHEDULE NO. 14
Performance Incentive Plan

APPLICABILITY
The Performance Incentive Plan replaces the current reasonableness or prudence review of Nashville Gas Company's (Nashville) gas purchasing activities overseen by the Commission. The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE
Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 75% / 25% basis.

The Company will have a cap on incentive gains and losses. During a plan year, Nashville's overall gains or losses cannot exceed $1.6 million. Also as a part of the Performance Incentive Plan, Nashville submitted a Three Year Supply Plan and will obtain additional firm gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin.

GAS PROCUREMENT INCENTIVE MECHANISM
The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs
- Gas Supply Reservation Fees
- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

COMMODITY COSTS

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+\ldots P_\propto K_\propto)+F_oO+F_dD;\text{ where}$$

$$F_f+F_o+F_d= 1;\text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TPG) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future. The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

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[1]Gas purchases under Nashville's supply contract on the Tetco system to serve Nashville's Hartsville system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[2]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

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[2]Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

Through the Capacity Management Incentive Mechanism, to the extent Nashville is able to release transportation or storage capacity in the secondary market, it will flow through to customers 75% of the associated cost savings and retain 25% of the cost savings. Transportation or storage margin (calculated as described above) associated with off-system or wholesale sales-for-resale will also flow through to customers on a 75/25 sharing basis.

Determination Of Shared Savings

The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No.______. Monthly, Nashville will compute the gain or loss using the approved formulas.

During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate non-interest bearing Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE COMMISSION

The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC REVIEW

Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized, and the composition of the utility's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Commission Staff.

Exhibit ____ (TES-3)

NASHVILLE FIRM TRANSPORTATION AND STORAGE ARRANGEMENTS

COMPANY NAME	SERVICE	CONTRACTED QUANTITY	EFFECTIVE DATE	EXPIRATION DATE	COMMENTS
TENNESSEE GAS PIPELINE	FT-A Firm Transportation	MDQ = 130,000 dt/d	9/1/93	11/1/00	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
COLUMBIA GULF	FTS1 Firm Transportation	MDQ = 5,000 dt/d OCT - MAR MDQ = 4,601 dt/d APR - SEPT	11/1/94	10/31/10	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
TEXAS EASTERN	SCT Firm Transportation	MDQ = 1,677 dt/d	6/1/93	10/31/12	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
TOTAL -- Peak Day Firm Transportation		MDQ = 136,677 dt/d			
COLUMBIA GAS	FSS Firm Storage	SCQ = 611,870 dt MDSQ = 10,000 dt/d MDIQ=4,906 dt/d	11/1/93	10/31/10	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
COLUMBIA GAS	SST Firm Storage Transportation	MDQ = 10,000 dt/d OCT - MAR MDQ = 5,000 dt/d APR - SEPT	11/1/93	10/31/10	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
TENNESSEE GAS PIPELINE	FS-MA Firm Storage	MSQ = 2,901,943 dt MDWQ = 49,828 dt/d MDIQ = 19,347 dt/d	5/1/94	11/1/00	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
TENNESSEE GAS PIPELINE	FS-PA Firm Storage	MSQ = 672,091 dt MDWQ = 6,072 dt/d MDIQ = 4,481 dt/d	9/1/93	11/1/00	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
CRYSTAL OIL COMPANY	HATTIESBURG Salt Dome Storage	MSQ = 200,000 dt MDWQ = 20,000 dt/d MDIQ = 10,000 dt/d	8/1/90	7/31/05	OPEN ACCESS, PREGRANTED ABANDONMENT CONTRACT SUBJECT TO ROFR
TOTAL Storage Capacity **TOTAL Storage Withdrawal Deliverability**		MSQ = 4,385,904 dt MDWQ = 85,900 dt/d			

04/18/96

Exhibit ___ (TES-4)

Nashville Firm Gas Supply Arrangements

SUPPLIER NAME (Pipeline)	QUANTITY	EFFECTIVE DATE	COMMODITY INDEX PRICE	EXPIRATION DATE	COMMENTS
Supplier A (Tennessee)	30,100 dt/d	09/01/93	INSIDE FERC 1st of Month	9/1/97	365-DAY SERVICE Summer Baseload 30,100 dt/d Winter Baseload 15,000 dt/d Swing Service 15,100 dt/d
Supplier B (Tennessee)	5,000 dt/d	11/01/95	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier C (Tennessee)	7,140 dt/d	11/01/94	INSIDE FERC 1st of Month	3/31/97	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier A (Tennessee)	4,960 dt/d	11/01/95	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier D (Tennessee)	6,186 dt/d	11/01/92	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier D (Tennessee)	10,000 dt/d	11/01/92	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier E (Tennessee)	5,000 dt/d	11/01/95	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier F (Tennessee)	5,714 dt/d	11/01/95	INSIDE FERC 1st of Month	3/31/00	WINTER ONLY SERVICE BASE LOAD ONCE NOMINATED
Supplier G (Columbia)	5,000 dt/d	11/01/93	INSIDE FERC 1st of Month	10/31/97	365-DAY SWING SERVICE
Supplier H (Tetco)	REQ. FOR HARTSVILLE	05/01/95	Fixed Commodity Rate per dt (Renegotiate Annually)	4/30/02	BUNDLED 365-DAY SWING SERVICE

Affidavit

State of North Carolina)
)
County of Mecklenburg)

Thomas E. Skains, being first duly sworn, deposes and says that he is the same Thomas E. Skains whose prepared testimony and exhibits accompany this affidavit.

Thomas E. Skains further states that, to the best of his knowledge and belief, his answers to the questions contained in such prepared testimony are true and accurate and that the exhibits accompanying the testimony were prepared by him under his direction and are correct to the best of his knowledge and belief.

Tho E. Skains

Thomas E. Skains

Sworn to and subscribed before me,
a Notary Public, on this the 18th day
of April, 1996.

Melanie H. Envy

My Commission Expires:

May 26, 1998

Tennessee Public Service Commission
Docket No. ________

Direct Testimony of Chuck W. Fleenor

on Behalf of

Nashville Gas Company,
a Division of
Piedmont Natural Gas Company, Inc.

Piedmont
Natural Gas
Company

I. Identification of Witness.

Q. Please state your name and business address.

A. My name is Chuck Fleenor. My business address is 1915 Rexford Road, Charlotte, North Carolina 28211.

Q. By whom are you employed and in what capacity?

A. I am employed by Piedmont Natural Gas Company, Inc., (Piedmont) as Vice President-Gas Services.

Q. Please summarize your educational and professional background.

A. I received a B.S. degree in Physics in 1972 from the University of North Carolina at Charlotte. In 1979 I received a Masters degree in Business Administration from the same university. I became a registered Professional Engineer in the state of North Carolina in 1980. In 1987, I became a registered Professional Engineer in the state of South Carolina. I was employed by Piedmont in 1974. Prior to my current position as Vice President-Gas Services, I held the positions of Engineer-Gas Supply, Manager-Technology, Director-Technology, Director-Energy Systems and Director-Gas Supply. I was promoted to Vice President - Gas Supply in 1985 and held that position until April 1, 1996 when my position changed to Vice President - Gas Services.

Q. What are your current responsibilities with Piedmont?

A. Of my various current responsibilities, those that are relevant to the issues of this proceeding include estimating the gas demand of Piedmont's various market segments to ensure that Piedmont has secure, adequate, competitively-priced gas and capacity to meet the peak, seasonal and annual needs of its various classes of customers.

Q. Have you previously testified before this Commission or any other regulatory authority?

A. Yes. I have testified before this Commission on several occasions. I have also testified before the South Carolina Public Service Commission, the North Carolina Utilities Commission and the Federal Energy Regulatory Commission.

Q. In what areas have you testified before federal or state regulatory agencies?

A. I have presented testimony on a number of issues, including cost of service studies, rate designs, cost of gas, projected sales and transportation volumes and revenue requirements. Of particular relevance to this proceeding, I have presented testimony concerning prudent purchasing practices before the North Carolina Utilities Commission and the South Carolina Public Service Commission. Additionally, I have developed the annual Gas Supply Plans with respect to the gas purchasing practices of Piedmont's Nashville division (Nashville). These Gas Supply Plans have been provided periodically to this Commission and its prudence auditors, RCG/Hagler, Bailly Inc. (RCG) and Theodore Barry & Associates (TB&A).

Q. What have been the results of the prudence reviews?

A. Piedmont has been found to be prudent in its gas purchasing practices in all three states in every single prudence review.

II. Purpose of Testimony.

Q. Please describe the purpose of your testimony in this proceeding.

A. I will describe Nashville's design day growth requirements and the Company's three year plan to meet those requirements through the winter of 1998-1999.

I also propose to establish a five percent "reserve margin" for Nashville as part of that plan.

III. Background.

Q. Briefly describe the nature of Nashville's growth.

A. In recent years, Nashville has experienced a growth rate several times the national average. Over the last five years, the average annual increase in net customers in Nashville has exceeded five percent per year. This increase is a result of additional high priority firm customers. Because of the degree of weather sensitivity displayed by these customers, design day and seasonal requirements for firm reliable gas service are increasing significantly.

Q. Please explain what you mean by "design day" requirements.

A. Piedmont determines a design day criteria based on probability. Briefly stated, a design day temperature has a probability of occurring on a weekday once in ten years. For Nashville, this temperature has been previously calculated to be 4.3 degrees Fahrenheit. Calculations are made using the weather sensitive characteristics of the firm customers to determine what the expected requirements of the Nashville system are for such a condition.

Q. Has such a methodology been reviewed by the state commissions having jurisdiction over Piedmont's planning and operation?

A. Yes. The procedures underlying this calculation have been reviewed during previous prudence reviews and most notably by RCG and TB&A. In all cases the procedure has been found to be appropriate.

IV. Explanation of Terms.

Q. What is meant by the term "reserve margin" and how does it apply to "design day" requirements?

A. A "reserve margin" is the amount by which available firm supply resources under contract (such as firm transportation entitlements on a pipeline and LNG deliverability) exceed the estimated firm requirements during a period of "design day" conditions.

Q. Is a reserve margin only available on a "design day"?

A. No. A reserve margin may also be used during other critical period conditions during extreme cold periods of winter weather.

Q. Why is it important to maintain a reserve margin?

A. There are a number of reasons for maintaining a reserve margin. These reasons include:

1) To cope with the uncertainty of demand estimates - Although most models in the industry today assume a linear relationship between temperature and gas consumption per customer, accurate long range weather predictions are unreliable and customer growth estimates provide additional uncertainties. Other factors such as wind, prior days' temperatures, precipitation and cloud cover also play a part in influencing demand predictions. The infrequent occurrence of design days necessarily result in the extrapolation of expected results beyond the range of data populations.

2) To supply colder-than-design temperature conditions - Most LDCs utilize a statistical probability to determine an occurrence criteria; however, the design criteria can be exceeded from time

to time.

3) <u>To accommodate supplier failure, transportation capacity losses, and facility problems</u> - Natural disasters and force majeure events can result in hurricane and freeze off damage to production facilities resulting in reductions in pipeline delivery pressures. Nashville depends on its LNG facility for 43% of its design day deliverability. Failure of equipment, such as pumps or vaporizers, could reduce portions of the full deliverability.

4) <u>To provide stand-by service</u> - Although Nashville interrupts service to its non-firm customers that have alternative fuels during design and critical periods, occasionally these customers experience emergency conditions such as failure of alternate equipment or total depletion of alternative fuels. In these cases, Nashville may provide emergency service at higher rates in order to prevent property damage or plant shut downs if doing so will not impair the security of firm customers.

5) <u>To meet future growth</u> - Both near term and long term growth projections are subject to error. Additionally, it is often difficult or impossible to acquire economically attractive incremental services in quantities that exactly match the expected growth in demand.

Q. Did the reviews performed by TB&A address the issue of maintaining a reserve margin?

A. Yes. In their report for operations ending June 30, 1994 in the section titled

"Finding: Peak Day (Short-Term) Reserve Margin Is Adequate," TB&A states, "Current pipeline contract sources, plus storage and LNG, amount to a peak day reserve of about 6%." In the most recent report TB&A calculated the reserve margin for the winter of 1994-1995 to be 7%.

Q. Did these reports find that Nashville was prudent?

A. Yes.

Q. What was the reserve margin for the winter of 1995-1996?

A. As indicated in Exhibit__(CWF-1) the reserve margin was entirely consumed by the continuing demand growth experienced by Nashville. When this condition was coupled with the critically cold weather actually experienced during this past winter, Nashville found itself with seriously depleted storage reserves by the time moderating spring weather finally arrived. Interruptions of sales service to non-firm customers were unprecedented.

V. Request of the Witness.

Q. Is Nashville requesting the use of a reserve margin in connection with the Performance Incentive Plan being proposed in this proceeding?

A. Yes. Exhibit__(CWF-1) entitled "Design Day Supply and Demand Schedule - Nashville" indicates a 5% reserve margin added to the Design Day Estimate in the calculation of Total Firm Requirements. When this reserve margin of approximately 13,300 dts per day is added to the annual expected growth in firm demand of 11,000 dts per day, the schedule indicates a need to acquire 24,300 dts per day of incremental peak day firm service for the winter of 1996-1997. This schedule also indicates the expected growth in requirements and supplies through the spring of 1999. Nashville is in the process of soliciting bids, evaluating proposals, and negotiating the price and terms of services that are needed to meet these requirements.

Q. Do you believe that this Commission should approve the utilization of a five percent "reserve margin" as a part of the Performance Incentive Plan being proposed in this proceeding?

A. Yes. Based upon information obtained about reserve margins utilized by other LDCs in the AGA study, "Analysis of LDC Peak Day Planning," the 7.5% reserve margin approved by this Commission in the United Cities Experimental Performance-based Ratemaking Mechanism, and my own experience in gas supply planning and dispatch, I believe the use of five percent reserve margin is justified. I do not intend to imply that our reserve margin will always be exactly five percent; however, we do request the Commission's approval for the use of a reserve margin of approximately five percent in the Performance Incentive Plan. This approval is important since after the Performance Incentive Plan is approved, the reserve margin will not be subject to prudence review. Nashville intends to monitor its particular needs and circumstances to determine if an adjustment would be appropriate at a later date.

Q. Does this conclude your testimony.

A. Yes. It does.

Design Day Supply and Demand Schedule - Nashville

	1995-96	1996-97	1997-98	1998-99
Design Day Estimate	255,000	266,000	275,000	285,000
Reserve Margin @ Approx 5%		13,300	14,000	14,300
Total Firm Requirements	255,000	279,300	289,000	299,300
Tennessee Gas Pipeline				
FT (365 day transport)	74,100	74,100	74,100	74,100
FS (60 day storage)	55,900	55,900	55,900	55,900
Columbia Gas				
FTS (365 day transport)	5,000	5,000	5,000	5,000
FSS (60 day storage)	10,000	10,000	10,000	10,000
Nashville - Local Storage				
LNG (10 day)	110,000	110,000	110,000	110,000
Total Existing Supplies	255,000	255,000	255,000	255,000
Incremental Supply Options				
Incremental Firm Services*		24,300	34,000	44,300
(Deficit) Surplus	0	0	0	0

* Nashville is presently arranging and negotiating for incremental services to balance "design day" requirements

Affidavit

State of North Carolina)
)
County of Mecklenburg)

Chuck W. Fleenor, being first duly sworn, deposes and says that he is the same Chuck W. Fleenor whose prepared testimony and exhibit accompany this affidavit.

Chuck W. Fleenor further states that, to the best of his knowledge and belief, his answers to the questions contained in such prepared testimony are true and accurate and that the exhibit accompanying the testimony was prepared by him under his direction and is correct to the best of his knowledge and belief.

Chuck W. Fleenor

Chuck W. Fleenor

Sworn to and subscribed before me,
a Notary Public, on this the 18th day
of April, 1996.

Melanie H. Eury

My Commission Expires:

May 26, 1998

Tennessee Public Service Commission
Docket No. _________

Direct Testimony of Jay P. Lukens

on Behalf of

Nashville Gas Company,
a Division of
Piedmont Natural Gas Company, Inc.

Piedmont
Natural Gas
Company

I. Introduction

Q. Please state your name, title, and business address.

A. My name is Jay Lukens. I am President of Energy Market Economics, Inc. (EME), and my business address is 9821 Katy Freeway, Suite 250, Houston, Texas 77024.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of Nashville Gas Company (Nashville).

Q. What is the role and purpose of your testimony?

A. EME was retained by Nashville to assist it in developing a performance-based gas cost recovery plan that is consistent with Nashville's corporate values, existing contracts, and strategic goals regarding gas procurement. I will be discussing concepts of incentive or performance-based rate-making. I will set forth criteria by which I believe incentive regulation plans should be evaluated, and I will discuss Nashville's plan in light of such criteria.

Q. Please summarize your background and experience.

A. I founded EME in December of 1995. Prior to that date, I had been Senior Vice President of Planning and Rates for Transcontinental Gas Pipe Line Corporation (Transco). I joined Transco in 1985, was promoted to Vice President in 1986, and to Senior Vice President in 1989. From 1987 until my departure in 1995, I was principally responsible for directing Transco's strategic planning, rates, and Federal regulatory affairs. During such period I was also Transco's principal policy witness in Federal Energy Regulatory Commission (FERC) proceedings. A list of the testimony I have submitted at FERC is presented as Exhibit No. ____(JPL-1) to this testimony.

Prior to my employment at Transco, I was employed by AT&T Communications where, from 1981 to 1985, I worked in an internal consulting group know as the Analytical Support Center. During my tenure, AT&T was in the process of divesting the regional Bell operating companies and beginning to respond to new competition from partially deregulated long distance carriers. As an internal consultant my work was project driven and covered a wide array of topics. A central theme during that period, however, was the development of pricing strategies in a partially deregulated market.

My educational background includes a B.A. in economics from Eckerd College, and a Ph.D. in economics from Texas A&M. I taught economics at Texas A&M from 1979 to 1981, and I was an adjunct faculty member teaching in the MBA program at Farleigh Dickinson University from 1981 to 1984.

Q. In your time at Transco, did you have any direct experience with incentive regulation?

A. Yes. I served as Transco's representative on the Rate Committee and the Policy Analysis Committee of the interstate pipeline trade association, the Interstate Natural Gas Association of America (INGAA). Following issuance of a research report on incentive regulation in 1989 by FERC's Office of Economic Policy[1] , INGAA formed a Task Force on Incentive Regulation to advise the INGAA Board of Directors in formulating its policy position before FERC. I was an active member of the Task Force during 1989-1992 when it was in existence. The Task Force, through the efforts of its members and through use of outside consultants, conducted an extensive study of the theory and practice of incentive regulation in a number of regulated industries in the U. S. and abroad.

Transco attempted to put theory into practice by filing a comprehensive incentive rate proposal at FERC in February of 1992[2]. I coordinated the efforts of a project team which included, among others, Professors Joseph Kalt and Adam Jaffee of Harvard University and Dr. A.

[1]Federal Energy Regulatory Commission (1989) *Incentive Regulation: A Research Report*, Office of Economic Policy, Technical Report.
[2]Federal Energy Regulatory Commission (1992) *Transcontinental Gas Pipe Line*, Docket No. CP92-378, Direct Testimony of Joseph P. Kalt, A. Larry Kolbe, and Jay P. Lukens.

Lawrence Kolbe of the Brattle Group. Our team formulated an incentive proposal based on "yardstick competition" among Transco's peer pipelines. Although the proposal was ultimately withdrawn as part of a settlement of another proceeding, in my view it stands today as the most ambitious and well thought-out incentive proposal filed at FERC.

II. **Theory of Incentive Regulation**

Q. Please describe the goals of incentive regulation.

A. The central purpose of incentive regulation is to lower the societal costs caused by the regulatory process. A cost-of-service regulatory process imposes two forms of costs on society. First, there are the direct administrative and legal costs borne by the regulatory body, the regulated utility, and intervening customers associated with rate cases, audits, prudence reviews and similar proceedings. Second, there are economic efficiency losses created by cost-of-service regulation. Traditional regulation has long been criticized for failing to provide regulated companies with adequate incentives for cost reduction, improvement of product quality, and product innovation over time. As regulatory policy has come to favor use of market based pricing where possible, there has been the additional concern that traditional cost-of-service regulation does not provide utilities with the incentives or the flexibility to meet greater competition.

Incentive regulation is intended to lower the societal costs of regulation first by simplifying the administrative burden of the regulatory process. The theory of performance-based regulation is to replace detailed cost-of-service calculations with performance measurement against appropriate benchmarks that are clearly definable and understood by all interest groups.

Incentive regulation is further intended to improve economic efficiency by creating reward and penalty measures that are similar to the forces of a competitive market. There is considerable variation among incentive plans in terms of what aspect of competitive market behavior is simulated. Some plans focus on prices, some on profits, and some on particular cost or quality measures. While incentive plans attempt to capture some of the "carrot and stick" of the competitive process, one must not lose sight of the fact that the utility is still regulated. Thus, incentive plans must balance simulation of market rewards and penalties with the need to protect consumer interests and the need to give the utility a fair opportunity to earn its allowed rate of return

Q. Have incentive programs been put in place elsewhere in the gas industry?

A. Yes. In May of 1995 the Tennessee Public Service Commission approved an experimental performance-based rate making mechanism for United Cities Gas Company. Programs have also been approved and put in place in California, New York, Iowa and Wisconsin. Proposals are pending approval in several other states, including Maryland and Missouri.

Q. Dr. Lukens, by what criteria should the Commission evaluate a gas cost incentive plan?

A. In reviewing the literature of incentive regulation, I find four recurrent themes in attempts to describe the attributes of a "good" plan. For ease of reference I will label the four attributes as "simplicity," "fairness," "alignment," and "strategic fit."

Q. Please describe the attribute of "simplicity."

A. As discussed above, a primary goal of incentive regulation is to reduce the direct costs of the regulatory process. A Byzantine plan, one that relies on data intensive calculations or micro-management of utility operations, is not likely to produce meaningful savings in the cost of regulation. The incentive mechanism, its method of performance measurement, and the results produced must be straightforward, easy to calculate and unambiguous in their interpretation in order to reduce the resources consumed by the regulatory process.

I would note that simplicity cannot be achieved without a cost. There is a tradeoff between the simplicity of an incentive mechanism and the variety of issues it can handle. As a practical matter, in designing an incentive plan one confronts issues that are best left outside the purview of the plan because designing the plan to incorporate such issues would cause complexity not offset by commensurate benefits.

Q. Please discuss what you mean by the "fairness" of an incentive plan?

A. Incentive plans should be designed to create "win-win" outcomes for customers and the regulated company. In order to create an expectation of "win-win" outcomes, the plan should be unbiased and there should be symmetrical treatment of customers and the company under the plan's reward and penalty provisions.

Q. Dr. Lukens, what do mean by "the plan should be unbiased?"

A. I borrow the term from statistics. A statistic is said to be unbiased when its expected value is equal to the quantity it was designed to estimate. Translated into the present context, I would characterize an incentive plan as unbiased when it is designed so that no gains or losses are built-in at the outset. If the company behaves as it has in the past without effecting new strategy, neither the company or the consumer would win or lose. "Win-win" outcomes will result from sharing the benefits created by affirmative actions taken by the company to lower costs.

Q. Please turn now to the concept of "alignment."

A. A well-designed incentive plan will align the interests of the regulated company and its customers. To achieve that result, the plan must be built around performance benchmarks that relate to outcomes that are (1) subject to utility management control and (2) meaningful to the consumer. It obviously makes no sense to measure something solely because it is in the control of management; at the same time the performance plan must recognize that there are forces beyond management control. A plan that balances these factors is said to be in alignment.

To help clarify the issue of alignment, consider a hypothetical incentive plan for an electric utility. An outcome that would be meaningful to the consumer might be to lower the retail rate for electricity from historic levels. This is not a reasonable benchmark, however, because the retail rate for electricity can be affected by inflation and other factors that are beyond the control of utility management. An alternative outcome that would be in control of management would be to improve the heat rate for a particular piece of generating equipment. This outcome may or may not be meaningful to consumers depending on how much electricity the equipment actually generates. An incentive plan that aligns the interests of consumers and the company will be built around measures that are subject to management's control <u>and</u> represent meaningful benefits for consumers.

Q. Please describe the last attribute of a good incentive plan, the concept of "strategic fit."

A. An incentive plan cannot be viewed in isolation. Virtually all incentive plans implemented in the natural gas industry in the U. S. are partial incentive systems that focus on a firm's performance in a specific area of operation. Unless designed and evaluated in the context of a coherent strategic plan, however, partial incentive plans may unintentionally create incentives for the company to make sub-optimal choices in other areas. For example, an incentive plan that rewards a company for reducing expenditures on employee training below a sustainable level may lead to a lower level of work force productivity over time. Even though the specific provisions of an incentive plan may be linked to short-run outcomes, the plan must be designed, presented, and judged in light of the longer term strategic goals of the company.

III. Nashville's Performance Incentive Plan

Q. Please give an overview description of the Nashville plan.

A. Nashville's Performance Incentive plan is comprised of two related components -- a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. In the Gas Procurement Incentive Mechanism, Nashville's total commodity gas costs are compared to a predefined benchmark gas cost calculated using a price index based on Nashville's gas purchase contract portfolio. The Capacity Management component is designed to encourage Nashville to actively market un-utilized capacity in the secondary market. The Nashville plan is a partial incentive system in that it focuses on gas costs, upstream transportation and storage. Such costs represent, however, roughly 50 percent of Nashville's total cost of service.

Q. Please describe the monthly commodity price index used in setting the benchmark gas cost.

A. The monthly price index is defined as

$$I = F_f\,(P_0\,K_0 + P_1K_1 + P_CK_C + \ldots + P_\alpha\,K_\alpha) + F_oO + F_d\,D\text{; where}$$

$$F_f + F_o + F_d = 1\text{; and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; and subscript C denotes Columbia Gas Transmission (CGT), Louisiana plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and the subscript α denotes new incremental firm services to which Nashville may subscribe in the future.. The commodity price index will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above. Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

F_o= the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC* first-of-the-month price indices plus applicable maximum IT rates and fuel retention from the source of gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d= the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily prices taken from *Gas Daily,* where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the rate payers, up to a maximum amount of gains or losses for Nashville of $1.6 million per year.

IV. Evaluation of Nashville's Performance Incentive Plan

Q. Does the Nashville Plan satisfy the criterion of simplicity?

A. Yes it does. In the Gas Procurement Incentive Mechanism, Nashville will compare the total commodity cost of gas to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual gas purchase quantities for the month by the price index defined above. Thus gas procurement performance is judged monthly based on the comparison of two numbers.

The Capacity Management Incentive is a straightforward sharing of net compensation associated with release of capacity rights on Nashville's transportation and storage contracts. Hence it too is simple to understand and administer.

Q. Will the plan reduce the burden of regulation?

A. Through approval of the plan Nashville hopes to eliminate prudence reviews and their attendant costs. Thus Nashville will have a clear understanding, at the time decisions are made, of its gas procurement performance benchmarks and the potential risks and rewards of alternative strategies. It is reasonable therefore to expect reduction in the direct cost of regulation and improvement in the effectiveness of Nashville's gas procurement efforts.

Q. Are any gas purchases omitted from the total monthly commodity cost of gas?

A. Yes. Purchases under Nashville's contract to serve the Hartsville system are not included in the plan. Nashville will continue to recover 100 percent of such costs through the PGA mechanism.

Q. Why does the plan omit purchases made to serve Hartsville?

A. Omission of the Hartsville contract was a judgment call made to preserve the simplicity of the plan. Harstville is an isolated part of Nashville's service territory, it is the only place where Nashville receives transmission service directly from Texas Eastern Pipeline, and it is a small, low load-factor delivery point. In light of these circumstances, Nashville's contract to serve this area is structured completely differently from any of its other long-term firm gas purchase contracts. Accommodating the Hartsville contract in the incentive plan would have caused complications to the plan without significant benefit, and I concur with the decision to omit it.

Q. Is the Nashville plan designed to be fair and unbiased?

A. Yes, I believe it is. The monthly commodity price index uses the same location price indices found in Nashville's contracts. The weights used in the index for first-of-the-month purchases are based on Nashville's actual capacity entitlements. Because the monthly commodity price index is constructed around Nashville's actual gas purchase and FT capacity contract portfolio, it is a very good predictor of Nashville's actual gas costs under a "do nothing" strategy. Nashville simulated the Plan results over the 1994 and 1995, and the benchmark gas costs were within 0.2 percent of actual city gate commodity cost of gas during such two year period. In order to generate benefits under the Gas Procurement Incentive Mechanism, Nashville must take affirmative action to reduce its commodity cost of gas.

Q. Why are the weights assigned to city gate, IT and daily spot market purchases in the monthly commodity price index allowed to vary to reflect actual purchase quantities?

A. As a preliminary matter, I should note that city gate, IT and daily spot purchases make up a very small fraction of Nashville's total gas purchases. In fact, during fiscal year 1995 Nashville made no city gate or IT purchases, and daily spot purchases comprised less than one percent of total purchases during the period. Historically, the primary reason Nashville has made daily spot purchases is to supplement storage gas supplies during periods of colder than normal weather. During the past winter, for example, cumulative degree days exceeded normal winter degree days by 14 percent. Had Nashville not made daily spot purchases, it would have substantially depleted storage in midwinter. By entering the daily market Nashville was able to husband storage supplies and thus preserved storage gas supplies to be available on extremely cold days. Because city gate and daily spot purchases are driven primarily by weather, over which management has no control, it is not fair or appropriate to fix a quantity of such purchases in determining the weights used in the monthly commodity price index.

Q. Does the plan align the goals and interests of rate payers and Nashville?

A. Yes, it does. The plan focuses the attention of Nashville management on the total commodity cost of gas and on the total net cost of storage and transportation capacity. Reductions in the commodity cost of gas below the benchmark index, and reductions in the net cost of capacity, will produce meaningful benefits to gas consumers in Nashville's service area.

Q. Is the plan consistent with Nashville's overall gas procurement strategy?

A. Yes. As I mentioned at the outset of my testimony, the goal from the start was to design an incentive plan that reflects Nashville's corporate values and strategies regarding gas procurement. Nashville's views on gas procurement are presented by Mr. Fleenor and Mr. Skains. In my view, the Company has put forth an incentive plan that reinforces its strategic goals as I understand them.

Q. Dr. Lukens, some issues are <u>not</u> specifically addressed by Nashville's plan. For example, do you concur with the decision not to include gas supply reservation charges in the incentive plan?

A. As a conceptual matter, I believe the outcome that should be rewarded in a gas procurement incentive plan is reduction of <u>total gas supply costs</u> below a market benchmark, including gas supply reservation costs. As a practical matter, however, we were unable to design a benchmark index for total gas supply costs that was appropriate for Nashville. At present there are no published sources for the market price of reserving firm gas supplies. The data available to Nashville are what it is paying and has paid for such rights. While it would have been possible to construct a benchmark from Nashville's historical experience, it would not have been the right thing to do in these circumstances from either a theoretical or practical perspective.

As a matter of theory, the natural gas industry has only recently emerged into the post-Order No. 636 industry structure. The direct marketing by producers and marketers to local distribution companies under firm contracts is still a recent arrangement, and there is no reason to think that prices paid to reserve firm gas supplies over the last several years will be good predictors of what prices may be in the future. Moreover as a practical matter, Nashville negotiated new or renegotiated reservation fees under most of its firm gas supply contracts in 1995. A benchmark based on an average of reservation fees paid over the past several years would be unfair to rate payers because it would build in "savings" when compared to prices actually being paid under the lower reservation fees established in 1995 and now in effect.

Adopting a benchmark for gas supply reservation fees based on historical data was rejected for the additional reason that it could have created conflict between the incentive plan and Nashville's gas procurement strategy. One of Nashville's values regarding gas procurement is to have sufficient firm gas supplies under contract to meet the needs of its high-priority residential and commercial customers. If, as is predictable, a benchmark based on historical data got out of step with the current market conditions, Nashville would face artificial incentives to change its gas purchasing practices. In order to preserve the incentive plan's strategic fit, we arrived at the compromise position of excluding gas supply reservation fees from the gas procurement incentive mechanism. Nashville will continue to recover such fees through the PGA, and for new contracts will employ the competitive bidding mechanism described by Mr. Skains.

Q. How does the use of futures contracts and similar financial instruments fit into Nashville's plan?

A To the extent Nashville uses such instruments, associated gains and losses will be subtracted from or added to the monthly commodity cost of gas and thereby will be shared with rate payers.

Q. How are storage costs treated in the plan?

A. Nashville will not change the accounting treatment currently used for storage gas supplies, that is, Nashville will continue to value storage inventory at the weighted average of prices paid at the time of injection. The plan gives Nashville the incentive to minimize the cost of gas supplies purchased for storage injections in the same way it gives it the incentive to minimize the cost of all gas purchases. Furthermore, if Nashville releases capacity rights to storage, net compensation will flow back as a credit to the costs of transportation and storage through the Capacity Management Incentive mechanism. Finally, Nashville may have the opportunity to participate in storage swaps where it can trade capacity rights to storage for lower gas costs. The benefits of such swaps would flow through the Gas Procurement or Capacity Management Incentive mechanisms as appropriate depending on the specific terms of the deal.

Q. What are your overall conclusions about the Nashville plan?

A. The incentive plan filed by Nashville is a workable program that will create benefits to Nashville's customers and shareholders while reducing the burden of regulation. The plan is simple and fair, and will it align the interests of Nashville and its customers to reduce the total delivered price of gas.

Q. What are your recommendations?

A. I recommend that the Tennessee Public Service Commission approve Nashville's plan as proposed.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

WITNESS EXPERIENCE OF JAY LUKENS
before the
FEDERAL ENERGY REGULATORY COMMISSION

1. FERC Docket No. RP95-197-000 (Phase II) Prepared Direct Testimony on Behalf of Leidy Line Roll-in Group (submitted 1/24/96). Supported rolled-in rate treatment forTransco's existing incrementally priced expansion projects.

2. FERC Docket No. RP95-197-000, General Rate Case. Prepared Direct Testimony (submitted 3/15/95) on general policy issues in rate case.

3. FERC Docket No. RP93-100, Dakota Gasification Settlement. Prepared Direct Testimony (submitted 12/19/94) supporting the terms and conditions of Transco's contract settlement with Dakota Gasification. Other Supplemental, Answering, and Rebuttal Testimony filed as case progressed.

4. FERC Docket No. RM94-4, Public Conference on Natural Gas Gathering Issues (2/24/94), testimony and response to questions before the Commission and their staff.

5. FERC Docket No. RP92-137, General Rate Case. Prepared Direct Testimony (submitted 3/17/92) on general policy issues in rate case. Primary issue in litigated phase of the case was the design of rates for production area services. Supplemental, Answering, and Rebuttal testimony filed as case progressed.

6. FERC Docket No. RP92-108, General Rate Case. Prepared Direct Testimony (submitted 3/10/92) supporting general policy issues in rate case.

7. FERC Docket No. CP92-378, Incentive Rate Proposal. Prepared Direct Testimony (submitted 2/28/92) on the design of an incentive rate mechanism for gas pipelines.

8. FERC Docket No. RM90-1, Public Conference on Pipeline Construction Rulemaking (1/28/92), testimony and response to questions before the Commission and their staff.

9. FERC Docket RP90-8, General Rate Case. Prepared Direct Testimony (submitted 10/24/89) on general policy issues in rate case. Supported proposal for \new transportation rate design consistent with unbundled service structure.

10. FERC Docket No. RP87-7, General Rate Case. Prepared Direct Testimony (submitted 6/21/89) on reserved issues of rate design and the terms and

conditions of transportation service. Supported proposal for a price deregulated secondary market in pipeline capacity rights.

11. FERC Docket No. TA85-3-89, Transition Gas Cost Issue. Prepared Answering Testimony (submitted 2/13/89) in remedies phase of FERC Enforcement action brought against Transco

Affidavit

State of North Carolina)
)
County of Mecklenburg)

Dr. Jay P. Lukens being first duly sworn, deposes and says that he is the same Dr. Jay P. Lukens whose prepared testimony and exhibits accompany this affidavit.

Dr. Jay P. Lukens further states that, to the best of his knowledge and belief, his answers to the questions contained in such prepared testimony are true and accurate and that the exhibits accompanying the testimony were prepared by him under his direction and are correct to the best of his knowledge and belief.

Dr. Jay P. Lukens

Sworn to and subscribed before me,
a Notary Public, on this the 18th day
of April, 1996.

Melanie H. Ewing

My Commission Expires:

May 26, 1998

Q. Are you the same Thomas E. Skains who submitted direct testimony in Docket No. 96-00805 in support of Nashville Gas Company's (Nashville) Performance Incentive Plan?

A. Yes, I am.

Q. Is Nashville proposing to amend the terms and conditions of its Performance Incentive Plan?

A. Yes. As a result of several meetings with the Consumer Advocate Division of the State of Tennessee Attorney General's Office (Consumer Advocate) in an effort to reach a non-contested resolution of this proceeding, Nashville is proposing to amend the plan in three specific areas.

Q. What are these proposed amendments?

A. First, Nashville proposes that interest be computed on the average monthly balance of the Incentive Plan Account (IPA) at the same interest rate and in the same manner as used to compute interest on the "Actual Cost Adjustment Account" of the Company's Purchased Gas Adjustment (PGA). Second, to the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month index prices, Nashville will modify the monthly commodity price index in the Gas Procurement Incentive Mechanism to reflect such discount. Third, the Capacity Management Incentive Mechanism has been modified to reflect a graduated sharing formula for net incentive benefits or costs, with the sharing percentages for Nashville ranging between zero and fifty percent.

Q. Are you sponsoring any exhibits with your supplemental testimony?

A. Yes. I am sponsoring Exhibit ___(TES-5) which is the revised tariff under which the proposed Performance Incentive Plan will be implemented. This tariff reflects the details of the amended terms and conditions of Nashville's Performance Incentive Plan which I summarized above.

Q. Mr. Skains, does this conclude your testimony?

A. Yes, it does.

SERVICE SCHEDULE NO. 14
Performance Incentive Plan

APPLICABILITY

The Performance Incentive Plan replaces the current reasonableness or prudence review of Nashville Gas Company's (Nashville) gas purchasing activities overseen by the Commission. The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE

Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company utilizing a graduated sharing formula, with sharing percentages for Nashville ranging between zero and fifty percent.

The Company will have a cap on incentive gains and losses. During the initial plan year, Nashville's overall gains or losses cannot exceed $1.6 million annually. Also as a part of the Performance Incentive Plan, Nashville submitted a Three Year Supply Plan and will obtain additional firm gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin.

GAS PROCUREMENT INCENTIVE MECHANISM

The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs
- Gas Supply Reservation Fees

- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

<u>COMMODITY COSTS</u>

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+...P_\propto K_\propto)+F_oO+F_dD; \text{ where}$$

$$F_f+F_o+F_d= 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (~~TPG~~) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and

TGP

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1 Gas purchases under Nashville's existing supply contract on the Tetco system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future.[2] The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[3]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The

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2 To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount.

3 Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-

resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	Sharing percentages Nashville/Customers. (Percent)
Less than or equal to 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

DETERMINATION OF SHARED SAVINGS

The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No. 96-00805. Nashville will compute the gain or loss using the approved formulas monthly.

During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in Nashville's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly

gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE COMMISSION

The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC REVIEW

Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized, and the composition of the utility's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Commission Staff.

Affidavit

State of Tennessee)
)
County of Davidson)

Thomas E. Skains, being first duly sworn, deposes and says that he is the same Thomas E. Skains whose prepared supplemental direct testimony and exhibit accompany this affidavit.

Thomas E. Skains further states that, to the best of his knowledge and belief, his answers to the questions contained in such prepared supplemental direct testimony are true and accurate and that the exhibit accompanying the testimony were prepared by him under his direction and are correct to the best of his knowledge and belief.

Thos E. Skains

Thomas E. Skains

Sworn to and subscribed before me,
a Notary Public, on this the 8th day
of May, 1996.

Marie Past Burke

My Commission Expires:

My Commission Expires JULY 27, 1996

Before The
Tennessee Public Service Commission
Nashville, Tennessee

Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company to Establish Performance Incentive Plan)	Docket No. 96-00805

Stipulation

Nashville Gas Company, Inc. (Nashville or the Company) and the Consumer Advocate Division of the State of Tennessee Attorney General's Office (Consumer Advocate) hereby stipulate and agree that:

1. On April 22, 1996, Nashville filed an application, tariffs, prefiled testimony and exhibits seeking approval of a performance incentive plan (Incentive Plan).

2. On April 30, 1996, the Commission gave notice that a hearing on the proposed Incentive Plan had been scheduled for May 9, 1996.

3. On May 2, 1996, the Consumer Advocate filed a Petition to Intervene, Suspend Tariff, and Continue based upon the concern that the Incentive Plan might result in the undercollection or overcollection of gas costs.

4. At various times, the Company responded to written and oral data requests from the Consumer Advocate. The Company represents that all information provided to the Consumer Advocate in response to these data requests is correct in all material respects to the best of the Company's knowledge and belief. All data supplied by the Company as confidential data in response to the data requests will be afforded confidential treatment in accordance with the non-disclosure agreement executed by the Company and the Consumer Advocate.

5. As a result of meetings between the Company and the Consumer Advocate, the Company agreed to amend the proposed Incentive Plan as follows:

   a. Interest will be computed on the average monthly balance of the Incentive Plan Account (IPA) at the same interest rate and in the same manner as used to compute interest on the "Actual Cost Adjustment Account" of the Company's Purchased Gas Adjustment (PGA).

   b. To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount and will provide notice to the Consumer Advocate of such modified monthly commodity price index.

c. To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	**Sharing percentages Nashville/Customers. (Percent)**
Up to and including 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

6. If either the Company or the Consumer Advocate believe that it may be appropriate to modify the $1.6 million cap on gains and losses set forth in the Incentive Plan, either may request a meeting in March 1997 to discuss the desirability of a change to be effective beginning with the second year of the Incentive Plan and each agrees to negotiate in good faith on any modification of the cap.

7. The Consumer Advocate having reviewed the Company's historical data, considered the gas market, and the representations of the Company is convinced that this Incentive Plan does not result in the undercollection or overcollection of gas costs. The Consumer Advocate will withdraw his Petition to Intervene, Suspend Tariff, and Continue and any objection to the Incentive Plan, upon the belief that this particular plan is in the public interest.

8. The Company agrees to support the Incentive Plan as amended by this Stipulation in any proceedings before the Commission to consider the Incentive Plan as amended. In the event the

Commission proposes to modify the Incentive Plan as amended by this Stipulation in a manner that is not acceptable to the Consumer Advocate or the Company, the Company will withdraw the Stipulation in its entirety and will file a motion with the Commission to set the Incentive Plan for hearing.

9. Each party entered into this Stipulation based on certain representations made by the other party. If a party should subsequently believe there has been any material misrepresentation on the part of the other party, the parties agree to discuss the concern and attempt to resolve it through good faith negotiations. If the parties are unable to resolve such concern through good faith negotiations, either party may petition the Commission to reopen this docket for the purpose of addressing such concern.

10. The Company and the Consumer Advocate agree not to take any action inconsistent with this Stipulation in any proceeding before the Commission in this docket; however, the parties further agree that the settlement of any issue pursuant to this stipulation shall not be cited as precedent in any other proceeding before this Commission. The provisions of this stipulation do not necessarily reflect the positions asserted by any party, and no party to this stipulation waives the right to assert any position in any future proceeding except to the extent set forth herein.

The foregoing is agreed and stipulated to, this the 8th day of May, 1996.

Nashville Gas Company

By: [signature]

Consumer Advocate Division

By: Daniel W. McCormac

BEFORE THE TENNESSEE PUBLIC SERVICE COMMISSION
Nashville, Tennessee

May 31, 1996

IN RE: APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS COMPANY TO ESTABLISH A PERFORMANCE INCENTIVE PLAN

DOCKET NO. 96-00805

This matter came on to be heard on May 9, 1996 upon the application of Nashville Gas Company (Nashville or Company), a division of Piedmont Natural Gas Company, Inc., to establish a performance incentive plan (Incentive Plan). At the hearing, the following appearances were entered:

FOR NASHVILLE GAS COMPANY

Joseph F. Welborn
Bass, Berry & Sims
2700 First American Center
Nashville, TN 37238-2700

Jerry W. Amos
Amos & Jeffries, LLP
P.O. Box 787
Greensboro, NC 27402

FOR ASSOCIATED VALLEY INDUSTRIES

Henry Walker
Boult, Cummings, Conners & Berry, PLC
414 Union Street, Suite 1600
P.O. Box 198062
Nashville, TN 37219

FOR THE CONSUMER ADVOCATE DIVISION OF
THE STATE OF TENNESSEE ATTORNEY GENERAL'S OFFICE

Vincent Williams
Consumer Advocate
450 James Robertson Parkway
Nashville, TN 37243-0485

FOR UNITED CITIES GAS COMPANY

Mark G. Thessin
5300 Maryland Way
Brentwood, TN 37027

On April 22, 1996, Nashville filed an application for approval of the Incentive Plan. According to the Company, the Incentive Plan will provide Nashville with incentives to acquire gas at the lowest reasonable cost consistent with a secure gas supply, eliminate the need for time consuming and costly prudence reviews, and reduce consumer gas rates.

The Incentive Plan as originally filed may be summarized as follows:

> **Effect on Existing Ratemaking Procedures.** Under the Incentive Plan, Nashville will be permitted to increase or required to decrease the margin component of its rates to reflect its performance gains or losses. No other changes would be required in existing ratemaking procedures. Nashville's base rates and base margin would continue to be established in general rate case filings. Nashville would continue to recover its gas costs under the existing PGA procedures and its GSR costs under the existing approved procedures. Nashville would also continue to adjust its rates as permitted by the WNA procedures.
>
> **General Description of Incentive Plan.** The Incentive Plan is comprised of two interrelated components--a Gas Procurement Incentive Mechanism and a Capacity Management Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's city gate commodity cost of gas is compared, and also addresses the recovery of gas supply reservation fees, the treatment of offsystem sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market offpeak unutilized transportation and storage capacity on pipelines in the secondary market.

General Description of the Gas Procurement Incentive Mechanism. The Gas Procurement Incentive Mechanism establishes a monthly benchmark dollar amount to which Nashville's actual city gate commodity gas costs are compared. If the total commodity gas purchase costs for a given month vary from the benchmark dollar amount by more than one percent (the monthly deadband), the variance or excess from the one percent deadband will be considered incentive gains or losses. These incentive gains or losses will be shared on a 50/50 basis between the company and its ratepayers subject to an overall annual cap of $1.6 million on gains or losses for Nashville under the plan. The benchmark dollar amount is established by multiplying total actual purchase quantities each month by a monthly price index. The monthly price index is a composite price referencing monthly index prices published by *Inside FERC* weighted by location according to Nashville's firm capacity rights each month on upstream pipelines for gas supplies purchased by Nashville in the first-of-the-month market and transported under Nashville's firm transportation (FT) contracts, monthly index prices published by *Inside FERC* for spot supplies purchased in the first of the month market and delivered to the city gate using transportation arrangements other than Nashville's FT contracts, and the weighted average daily index prices published by *Gas Daily* for Nashville's daily spot purchases.

Reservation Fees. Nashville would continue to pass through reservation fees paid to gas suppliers on a dollar for dollar basis (with no profit or loss potential). With respect to new or replacement supply arrangements or price renegotiations under existing arrangements, Nashville would solicit bids or proposals for service and choose the best bid for the firm service Nashville requires consistent with its "best cost" gas procurement strategy. Nashville would continue to reserve the right to offer existing suppliers (who have performed well under expiring contracts) a right of first refusal to match the best bid.

Offsystem Sales and Wholesale Sale for Resale Transactions. Any margin generated as the result of offsystem sales or wholesale sale for resale transactions using Nashville's firm transportation or storage capacity entitlements (the costs of which are recovered from Nashville's ratepayers) would be credited to gas costs and would be shared with ratepayers under the Gas Procurement Incentive Mechanism. Margin would be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville would impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is already taken into account under the plan. As to transportation costs, Nashville would impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs would be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin would be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Financial and Other Private Contracts. To the extent Nashville uses futures contracts, other financial derivative products, storage swap arrangements or other private contractual arrangements to hedge, manage or reduce gas costs, it would flow through any gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

Capacity Management Incentive Mechanism. The Capacity Management Incentive Mechanism is designed to provide Nashville an incentive to release unutilized offpeak firm transportation or storage capacity in the secondary interstate market and reduce Nashville's demand charges paid under those contracts to pipelines. The plan would flow back to Nashville's ratepayers 75% of the resulting cost savings and credit Nashville with 25% of the savings. Transportation or storage margin embedded in offsystem sales or wholesale interstate sale for resale transactions (as described above) would also be subject to the same variable sharing formula. Like the other components of Nashville's incentive plan, the Capacity Management Incentive Mechanism would be subject to the $1.6 million overall annual cap on gains and losses for Nashville established for the plan.

New Pipeline Capacity Demand Costs and Gas Supply Reservation Fees. New pipeline capacity demand costs and/or gas supply reservation fees would be recovered through the PGA on a dollar for dollar basis (with no profit or loss potential). Nashville would solicit bids and will choose the bid which best matches Nashville's requirements. As new firm transportation capacity or supply services are added to Nashville's portfolio, Nashville would amend the monthly price index formula set forth in the Gas Procurement

Incentive Mechanism to take into account any new weighting of capacity entitlements within the supply zones.

Cap on Gain and Losses. Nashville would be limited to overall gains or losses totaling $1.6 million under the Incentive Plan in any plan year. Such gains or losses would form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve month period.

Accounting Procedures. Each month during the term of plan, Nashville would compute any gains or losses under the Incentive Plan. If Nashville earns a gain, a separate non-interest bearing Incentive Plan Account (IPA) would be debited with such gain. If Nashville incurs a loss, that same IPA would be credited with such loss. The offsetting entries to IPA gains or losses would be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available. Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefits from any gas cost reductions resulting from the plan, would be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement would be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month would be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product would be credited or debited to the IPA, as appropriate. The balance in the IPA would be tracked as a separate collection mechanism.

Reports. Nashville would file interim quarterly reports of the IPA account with the Commission not later than 60 days following the end of each fiscal quarter and would file an annual report of IPA activity not later than 60 days following the end of each plan year.

Proposed Effective Date. Nashville requests an effective date of July 1, 1996, with the first plan year continuing through June 30, 1997. The plan would rollover into a second year commencing July 1, 1997 and ending June 30, 1998 with the agreement of Nashville and the approval of the Commission. Nashville would inform the Commission of its intention to roll over the plan for a second year no later than April 1, 1997.

In conjunction with the proposed Incentive Plan, Nashville also proposed to establish a five percent "reserve margin."

On April 30, 1996, the Commission gave notice that it had scheduled a hearing in this matter for May 9, 1996 at 9:00 a.m. in the Commission Hearing Room on the Ground Floor at 460 James Robertson Parkway, Nashville, Tennessee.

On May 2, 1996, the Consumer Advocate filed a Petition to Intervene, Suspend Tariff, and Continue. On April 30, 1996, United Cities Gas Company (United Cities) filed a Petition to Intervene. On May 7, 1996, Associated Valley Industries Group (AVI) filed a Petition to Intervene. On May 9, 1996, the Consumer Advocate filed a motion to withdraw.

On May 9, 1996, the hearing was held as scheduled. At the start of the hearing, counsel for Nashville announced that as a result of discussions with representatives of the Consumer Advocate, the Company had agreed to make the following modifications to the Incentive Plan:

a. Interest will be computed on the average monthly balance of the Incentive Plan Account (IPA) at the same interest rate and in the same manner as used to compute interest on the "Refund Due Customers' Account" of the Company's Purchased Gas Adjustment (PGA).

b. To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount.

c. To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	**Sharing percentages Nashville/Customers. (Percent)**
Up to and including 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

A copy of the tariff containing the modified Incentive Plan was received in evidence along with the prefiled direct and supplemental direct testimony of the Company. The Company's witnesses were made available for cross examination.

At the conclusion of the hearing, Commissioner Hewlett made a motion to approve the proposed Incentive Plan as modified by the agreement between Nashville and the Consumer Advocate and to direct the Company and the Commission Staff to recommend a qualified independent consultant to review the progress of this mechanism and to annually report their findings to the Commission. The motion was seconded by Commissioner Kyle and unanimously adopted.

IT IS THEREFORE ORDERED:

1. That Nashville Gas Company's Service Schedule No. 14, Performance Incentive Plan, as attached to this Order is approved effective July 1, 1996.

2. That the first plan year shall begin on July 1, 1996 and end on June 30, 1997. The Incentive plan will rollover into a second year commencing July 1, 1997 and ending June 30, 1998 upon the request of the Company and the approval of the Commission.

3. That Nashville Gas Company is relieved of any responsibility for prudence reviews during the initial term of the Incentive Plan and any extension thereof.

4. That the Company and the Commission Staff recommend a qualified independent consultant to review the progress of the approved Incentive Plan and to annually report their findings to the Commission.

5. That the five percent (5%) reserve margin proposed by Nashville as part of the Incentive Plan is approved.

6. That any party aggrieved with the Commission's decision in this matter may file a Petition for Reconsideration with the

Commission within the (10) days from and after the date of this order.

7. That any party aggrieved with the Commission's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Division, within sixty (60) days from and after the date of this order.

**

CHAIRMAN

Stephen Hewlett

COMMISSIONER

Sara Kyle

COMMISSIONER

ATTEST: Eddie Roberson

EXECUTIVE DIRECTOR

** Chairman Bissell voted in favor of this petition as reflected in the transcript in this docket.

SERVICE SCHEDULE NO. 14

Performance Incentive Plan

APPLICABILITY

The Performance Incentive Plan replaces the current reasonableness or prudence review of Nashville Gas Company's (Nashville) gas purchasing activities overseen by the Commission. The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE

Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company utilizing a graduated sharing formula, with sharing percentages for Nashville ranging between zero and fifty percent.

The Company will have a cap on incentive gains and losses. During the initial plan year, Nashville's overall gains or losses cannot exceed $1.6 million annually. Also as a part of the Performance Incentive Plan, Nashville submitted a Three Year Supply Plan and will obtain additional firm gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin.

GAS PROCUREMENT INCENTIVE MECHANISM

The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs
- Gas Supply Reservation Fees

- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

COMMODITY COSTS

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+\ldots P_\alpha K_\alpha)+F_oO+F_dD;\text{ where}$$

$$F_f+F_o+F_d=1;\text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (~~TPG~~) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and

TGP

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[1] Gas purchases under Nashville's existing supply contract on the Tetco system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future.[2] The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[3]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The

---

2 To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount.

3 Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-

resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	Sharing percentages Nashville/Customers. (Percent)
Less than or equal to 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

DETERMINATION OF SHARED SAVINGS

The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No. 96-00805. Nashville will compute the gain or loss using the approved formulas monthly.

During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in Nashville's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly

gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE COMMISSION

The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC REVIEW

Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized, and the composition of the utility's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Commission Staff.

Affidavit

State of Tennessee)
)
County of Davidson)

Thomas E. Skains, being first duly sworn, deposes and says that he is the same Thomas E. Skains whose prepared supplemental direct testimony and exhibit accompany this affidavit.

Thomas E. Skains further states that, to the best of his knowledge and belief, his answers to the questions contained in such prepared supplemental direct testimony are true and accurate and that the exhibit accompanying the testimony were prepared by him under his direction and are correct to the best of his knowledge and belief.

Thomas E. Skains

Sworn to and subscribed before me,
a Notary Public, on this the 8th day
of May, 1996.

Marie Past Burke

My Commission Expires:

My Commission Expires JULY 27, 1996

JWA

AMOS & JEFFRIES, L.L.P.
ATTORNEYS AND COUNSELLORS AT LAW
1230 RENAISSANCE PLAZA
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December 30, 1996

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company submits the accompanying summary of shared gas cost savings at the end of Nashville's fiscal quarter ended October 31, 1996.

As the enclosed summary indicates, the Company was able to achieve total gains and savings of \$347,704 under the gas procurement and capacity management mechanisms as defined by the Plan. Under the Plan's sharing formulas, \$303,564 of these gains and savings will be allocated to the Company's ratepayers. The remaining \$44,140 of the gains and savings are to be credited to the Company's Incentive Plan Account under the terms of the Plan.

Detailed calculations supporting the amounts shown in the summary have been provided to the Tennessee Regulatory Authority Staff and to the Consumer Advocate subject to non-disclosure agreements.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos by David R. Campbell

Jerry W. Amos

JWA/mh

Enclosure

c: Hal Novak, w/enclosures
Vincent Williams, Consumer Advocate, w/enclosures
Frank Creamer, w/enclosures

Fiscal Quarter Report on Nashville Incentive Plan
July 1996 - October 1996

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI 50% Sharing Gain/(Loss)	Ratepayer GPI 50% Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 2/	Ratepayer CMI Sharing Gain/(Loss) 2/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1996	$0.00	$0.00	$0.00	$23,909.30	$0.00	$23,909.00	$23,909.30	$0.00	$23,909.00
Aug	1996	$0.00	$0.00	$0.00	$61,929.77	$0.00	$61,929.77	$61,929.77	$0.00	$61,929.77
Sept	1996	$0.00	$0.00	$0.00	$86,549.13	$0.00	$86,549.13	$86,549.13	$0.00	$86,549.13
Oct	1996	$78,669.00	$39,334.50	$39,334.50	$96,647.03	$4,805.18	$91,841.85	$175,316.03	$44,139.68	$131,176.35
YTD		$78,669.00	$39,334.50	$39,334.50	$269,035.23	$4,805.18	$264,229.75	$347,704.23	$44,139.68	$303,564.25

1/The monthly gain or loss set forth in this column reflects gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

2/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings).
Total capacity demand costs for the period were annualized over the actual plan year based on currently approved demand rates. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers. (See Service Schedule No. 14, page 5)

PROTECTED MATERIALS REMOVED

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

January 2, 1997

IN RE:	APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS COMPANY TO ESTABLISH A PERFORMANCE INCENTIVE PLAN	Docket No. 96-00805

ORDER

This matter involves an application of Nashville Gas Company (Nashville Gas or the Company), a division of Piedmont Natural Gas Company, Inc., to establish a performance incentive plan. This application was approved, subject to certain conditions, by Order of The Tennessee Public Service Commission dated May 31, 1996. One of the conditions required by the Order was that the Company and the Commission Staff recommend a qualified independent consultant to review the progress of the approved Incentive Plan and to annually report their findings to the Commission, with the cost of such audit to be recovered through the Company's Actual Cost Adjustment (ACA) Account.

On November 27, 1996, Nashville Gas and the Authority Staff submitted for the Authority's approval, a contract for Andersen Consulting to review the progress of the Incentive Plan.

The Authority considered this matter at its regularly scheduled Conference held on December 3, 1996. The Authority is of the opinion that the recommendation of the Company and the Staff to employ Andersen Consulting is appropriate and the contract should be approved.

IT IS THEREFORE, ORDERED:

1. That the Nashville Gas contract with Andersen Consulting dated November 21, 1996, attached to this Order be, and the same is, hereby approved;

2. That any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from and after the date of this Order; and

3. That any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within Sixty (60) days from and after the date of this Order.

CHAIRMAN

DIRECTOR

DIRECTOR

ATTEST:

EXECUTIVE SECRETARY

ANDERSEN
CONSULTING

RECEIVED

DEC 2 0 1996

TN REGULATORY AUTHORITY
GENERAL COUNSEL'S OFFICE

November 21, 1996

Mr. William H. Novak
Utility Rate Division Manager
Energy and Water Section
Tennessee Regulatory Authority
360 James Robertson Parkway
Nashville, TN 37243-0505

Mr. Chuck Fleenor
Piedmont Natural Gas Company
1915 Rexford Rd.
Charlotte, NC 28211

Re: Performance Incentive Ratemaking Review

Dear Hal and Chuck:

Thank you for the opportunity to provide a review of Nashville Gas Company, a Division of Piedmont Natural Gas experimental performance incentive plan. We understand that your principal objectives for the effort are as follows:

- Comply with paragraph 4 of the Regulatory Authority Order dated May 31, 1996 requiring that the company and Regulatory Authority staff recommend an independent consultant to review the progress of the plan and report to the Regulatory Authority compliance with the guidelines set forth in the order.

- Determine if proper incentives are in place and what, if any further modifications should be made to the program.

This letter represents our understanding of your needs, our proposed method of achieving your objectives, and a preliminary cost estimate. In order to achieve these objectives, we propose to:

- Provide an independent, unbiased analysis of the performance incentive plan.

- Provide this analysis at the direction of the Regulatory Authority and on the behalf of the rate payors of Tennessee.

Based on our discussions and a review of the information previously sent to us, we purpose an initial meeting with Piedmont in late December/early January.

ANDERSEN
CONSULTING

November 21, 1996
Mr. William H. Novak
Mr. Chuck Fleenor

Outcomes/Deliverables

As a result of our initial meeting, we will have established the following guidelines for the completion of the project:

- A strawman "Table of Contents" for the report
- A Scope, Schedule, and Deliverables
- Scheduled date and format for meeting with Hal Novak at the Tennessee Regulatory Authority
- A data reporting format, mechanism (i.e. electronic copy vs. paper copy), and schedule

Staffing

Frank Creamer, an Andersen Associate Partner, is assigned to conduct the engagement. He may be supplemented by an Andersen consultant/or analyst on an as-need basis.

Cost

Based on my current understanding of the scope, our cost for professional fees, excluding travel and lodging, will be on a not to exceed basis of $50,000. Piedmont also agrees to pay actual travel and lodging expenses that typically averages between 10-15% of professional fees. All invoices will be billed to Piedmont and is due and payable upon receipt.

Interim deliverables will be reviewed with all parties on an ongoing basis to ensure that we continue to meet your expectations.

Timing

Time is of the essence. In order to meet the report due date, we do request an early approval to this engagement letter.

ANDERSEN CONSULTING

November 21, 1996
Mr. William H. Novak
Mr. Chuck Fleenor

We appreciate the opportunity to be of service to the Regulatory Authority, the rate payors of Tennessee, and Piedmont Natural Gas. If you have any questions or concerns regarding this proposal, please feel free to contact myself or Frank Creamer at (312) 507-5703.

Sincerely,

ANDERSEN CONSULTING LLP

By Anthony C. Rich

Anthony C. Rich

DB

Accepted by : Thomas E Skains

(Signature)

Thomas E Skains

(Type Name)

Title: Senior Vice President

Date: December 3, 1996

CMC
HRM

AMOS & JEFFRIES, L.L.P.
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March 31, 1997

RECEIVED

APR 02 1997

TN REGULATORY AUTHORITY
UTILITY RATE DIVISION

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying summary of shared gas cost savings for the period July, 1996 through January 31, 1997. This summary provides the results of activity under the plan for the fiscal quarter ended January, 1997. For the reasons set forth in the following paragraph, it also restates the previously reported activity under the plan for the period July, 1996 through October, 1996.

Since the filing of our last report, Nashville's annual demand charges have decreased due to pipeline rate case settlements before the Federal Energy Regulatory Commission (FERC). As a result, the savings achieved under the Capacity Management Incentive mechanism have been restated to reflect the reduced annual demand charges. In addition, the original report reflected gains and savings achieved under the Gas Procurement Incentive mechanism after application of the one percent deadband. This filing recognizes total gains and savings achieved under the Gas Procurement Incentive mechanism including those realized within the one percent deadband.

For the fiscal quarter ended October, 1996, the Company was able to achieve total gains and savings of $438,704 under the gas procurement and capacity management mechanisms as defined by the Plan. Under the Plan's sharing formulas, $362,882 of these gains and savings will be allocated to the Company's ratepayers. The remaining $75,823 of the gains and savings will be credited to the Company's Incentive Plan Account under the terms of the Plan.

As the summary indicates, the accumulated gains and savings under the plan thus far in the plan year total $829,639. Of this amount, $707,081 have accrued to the Company's ratepayers. The remaining $122,558 will be credited to the Company's Incentive Plan Account.

Detailed calculations supporting the amounts shown in the summary have been provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate subject to the execution of non-disclosure agreements.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos

JWA:kam
Encl.

Report on Nashville Incentive Plan
July 1996 - January 1997

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1996	$31,685	$0	$31,685	$23,909	$0	$23,909	$55,594	$0	$55,594
Aug	1996	($13,395)	$0	($13,395)	$61,930	$0	$61,930	$48,535	$0	$48,535
Sept	1996	($7,996)	$0	($7,996)	$86,549	$0	$86,549	$78,553	$0	$78,553
Oct	1996	$111,606	$39,335	$72,271	$96,647	$7,401	$89,247	$208,253	$46,735	$161,517
Nov	1996	($4,294)	$0	($4,294)	$233,751	$40,284	$193,467	$229,457	$40,284	$189,173
Dec	1996	$1,652	$0	$1,652	$78,238	$19,560	$58,679	$79,890	$19,560	$60,331
Jan	1997	$95,366	$0	$95,366	$33,991	$15,979	$18,012	$129,357	$15,979	$113,378
YTD		$214,624	$39,335	$175,289	$615,015	$83,223	$531,792	$829,639	$122,558	$707,081

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the period were annualized over the actual plan year based on currently approved demand rates. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers. (See Service Schedule No. 14, page 5)

Piedmont Natural Gas Company

Thomas E. Skains
Senior Vice President, Gas Supply

Post Office Box 33068
Charlotte, North Carolina 28233

March 31, 1997

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., to Establish a Performance Incentive Plan
Docket No. 96-00805

Dear Mr. Waddell:

By Order dated May 9, 1996 in Docket No. 96-00805, the Tennessee Public Service Commission (Commission), predecessor to the Tennessee Regulatory Authority ("Authority"), approved a performance incentive plan ("Incentive Plan") for Nashville Gas Company (the "Company"), a division of Piedmont Natural Gas Company, Inc. The Incentive Plan became effective July 1, 1996, with the first plan year continuing through June 30, 1997. The Plan is to roll-over into a second year commencing July 1, 1997 and ending June 30, 1998 with the agreement of the Company and the approval of Commission (now the Authority). Nashville Gas was instructed to inform the Commission (now the Authority) no later than April 1, 1997 of its intention to roll-over the Plan for a second year.

In light of the significant reduction in gas costs achieved by the Company during the first plan year to date (as evidenced by the second fiscal quarter report filed this date), the Company proposes to roll-over the Incentive Plan for a second year without modification and hereby requests the Authority to approve the roll-over prior to the July 1, 1997 commencement date of the second year of the Incentive Plan. If the parties agree to the requested one year rollover, it is requested that approval be made without the necessity of a hearing before the Authority.

I am enclosing an additional copy of this letter that I would appreciate your stamping filed and returning in the enclosed envelope.

Sincerely,

cc Vincent Williams, Consumer Advocate
Henry Walker, AVI
Hal Novak, Tennessee Regulatory Authority
Frank Creamer, Andersen Consulting

Officers
Directors
SCF
JWA

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

June 30, 1997

In Re:

Application of Nashville Gas Company, A Division of Piedmont Natural Gas Company to Establish A Performance Incentive Plan	)))	Docket No. 96-00805

ORDER AUTHORIZING INCENTIVE PLAN FOR SECOND YEAR

This matter comes before the Tennessee Regulatory Authority ("Authority") for consideration pursuant to a letter sent to the Authority from Nashville Gas Company ("Nashville Gas" or "Company") and a prior Order of the Tennessee Public Service Commission ("Commission") Upon consideration of the letter sent and the prior Commission Order, the Authority finds the following

1. On May 31, 1996, the Commission, the predecessor to the Authority, approved a performance incentive plan ("Incentive Plan") for Nashville Gas for a two year period beginning July 1, 1996.

2 In the original Order approving the Incentive Plan, the Commission specified that if Nashville Gas was to continue the Incentive Plan for a second year, that the Company inform the Commission by April 1, 1997

3. By letter dated March 31, 1997, the Company informed the Authority that it proposed to roll-over the Incentive Plan for a second year without modification. The Company requested the Authority approve the roll-over prior to July 1, 1997, the commencement date of the second year of the Incentive Plan. The Company further requested that the one year roll-over be approved without the necessity of a hearing before the Authority.

4. By letter dated April 7, 1997, Associated Valley Industries stated that it did not object to the Company's requests No party filed an objection to the Company's requests. By a report dated May 1, 1997, Andersen Consulting filed its first year review

of the Company's performance incentive plan and recommended that the plan roll-over for year two without modification

5. The Authority considered this matter at its regularly scheduled conference on May 20, 1997. The Authority finds that the Company should be allowed to roll-over the Incentive Plan for a second year commencing July 1, 1997, and that no hearing is necessary before the Authority since no party objected to the roll-over.

IT IS THEREFORE ORDERED THAT:

1. The Company is hereby authorized to roll-over the Incentive Plan for a second year commencing July 1, 1997;

2. No hearing is necessary for this matter since no objections were received by the Authority objecting to the roll-over;

3 Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within (10) days from the date of this Order; and

4 Any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty (60) days from the date of this Order.

Lynn Greer / pm
CHAIRMAN

Sara Kyle
DIRECTOR

DIRECTOR

ATTEST:

K David Waddell
EXECUTIVE SECRETARY

FILE COPY
RATE DEPT.

AMOS & JEFFRIES, L.L.P.
ATTORNEYS AND COUNSELLORS AT LAW
1230 RENAISSANCE PLAZA
230 NORTH ELM STREET
POST OFFICE BOX 787
GREENSBORO, NORTH CAROLINA 27402

TELEPHONE: (910) 273-5569

FACSIMILE: (910) 273-2435

August 28, 1997

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying annual report of shared gas cost savings for the plan year ended June 30, 1997.

As the summary indicates, the accumulated gains and savings under the plan for the plan year total $1,379,383. Of this amount, $924,554 have accrued to the Company's ratepayers. The remaining $454,829 has been credited to the Company's Incentive Plan Account (IPA).

Detailed calculations supporting the amounts shown in the summary for the period July, 1996 through April, 1997 have been previously provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate. Supporting calculations for May, 1997 and June, 1997 are provided in this filing subject to the execution of non-disclosure agreements. As permitted by the provisions of the approved tariff, the Company will file a rate adjustment on or about October 1, 1997 to amortize the collection of the June 30, 1997 IPA balance over the 12 month period beginning November 1, 1997 and ending October 31, 1998.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos

Enclosure

c: L. Vincent Williams, Consumer Advocate
Frank Creamer, Andersen Consulting
Hal Novak, Tennessee Regulatory Authority

Report on Nashville Incentive Plan
July 1996 - June 1997

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1996	$31,685	$0	$31,685	$23,909	$0	$23,909	$55,594	$0	$55,594
Aug	1996	($13,395)	$0	($13,395)	$61,930	$0	$61,930	$48,535	$0	$48,535
Sept	1996	($7,996)	$0	($7,996)	$86,549	$0	$86,549	$78,553	$0	$78,553
Oct	1996	$111,606	$39,335	$72,271	$96,647	$9,468	$87,180	$208,253	$48,802	$159,451
Nov	1996	($4,294)	$0	($4,294)	$233,751	$46,485	$187,266	$229,457	$46,485	$182,972
Dec	1996	$1,652	$0	$1,652	$78,238	$34,046	$44,193	$79,890	$34,046	$45,845
Jan	1997	$95,366	$0	$95,366	$33,991	$16,995	$16,995	$129,357	$16,995	$112,361
Feb	1997	($29,407)	$0	($29,407)	$214,472	$107,236	$107,236	$185,065	$107,236	$77,829
Mar	1997	($13,595)	$0	($13,595)	$245,883	$122,941	$122,941	$232,288	$122,941	$109,346
Apr	1997	($28,081)	$0	($28,081)	$19,077	$9,538	$9,538	($9,004)	$9,538	($18,543)
May	1997	($10,784)	$0	($10,784)	$70,761	$35,380	$35,381	$59,977	$35,380	$24,598
June	1997	$14,608	$0	$14,608	$66,810	$33,405	$33,405	$81,418	$33,405	$48,013
YTD		$147,365	$39,335	$108,030	$1,232,018	$415,495	$816,523	$1,379,383	$454,829	$924,554

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the plan year were based on actual demand costs as adjusted by refunds or surcharges from pipeline and storage suppliers for the plan year. (See Service Schedule No. 14, page 5)

PROTECTED MATERIALS REMOVED

AMOS & JEFFRIES, L.L.P.
ATTORNEYS AND COUNSELLORS AT LAW
TELEPHONE: (910) 273-5569 1230 RENAISSANCE PLAZA FACSIMILE: (910) 273-2435
230 NORTH ELM STREET
POST OFFICE BOX 787
GREENSBORO, NORTH CAROLINA 27402

December 23, 1997

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company submits the accompanying summary of shared gas cost savings at the end of Nashville's fiscal quarter ended October 31, 1997.

As the enclosed summary indicates, the Company was able to achieve total gains and savings of $608,461 under the gas procurement and capacity management mechanisms as defined by the Plan. Under the Plan's sharing formulas, $469,820 of these gains and savings will be allocated to the Company's ratepayers. The remaining $138,641 of the gains and savings are to be credited to the Company's Incentive Plan Account under the terms of the Plan.

Detailed calculations supporting the amounts shown in the summary have been provided to the Tennessee Regulatory Authority Staff and to the Consumer Advocate subject to non-disclosure agreements.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos by BKM

Jerry W. Amos

JWA/mh

Enclosure

c: Hal Novak, w/enclosures
Vincent Williams, Consumer Advocate, w/enclosures
Frank Creamer, w/enclosures

Report on Nashville Incentive Plan
July 1997 - October 1997

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1997	($7,269)	$0	($7,269)	$21,101	$0	$21,101	$13,832	$0	$13,832
Aug	1997	$278,151	$123,328	$154,823	$151,044	$1,843	$149,201	$429,195	$125,171	$304,024
Sept	1997	$13,416	$0	$13,416	$68,762	$6,876	$61,886	$82,178	$6,876	$75,302
Oct	1997	$57,431	$4,011	$53,420	$25,825	$2,583	$23,242	$83,256	$6,594	$76,662
YTD		$341,729	$127,339	$214,390	$266,732	$11,302	$255,430	$608,461	$138,641	$469,820

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the period are based on estimated annual costs for the plan year. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers. (See Service Schedule No. 14, page 5)

NON-DISCLOSURE AGREEMENT

Whereas, Nashville Gas Company (Nashville) has filed with the Tennessee Regulatory Authority ("TRA") in Docket No. 96-00805 a summary of its shared gas cost savings for the period July 1, 1997 through October 31, 1997; and

WHEREAS, the TRA Staff, the Consumer Advocate of the State of Tennessee ("Consumer Advocate") and Frank Creamer have requested supporting calculations for the summary information ("Supporting Calculations"); and

WHEREAS, Nashville believes that the disclosure of the Supporting Calculations to the public or to certain members of the public could adversely affect Nashville's ability to obtain favorable terms in future negotiations for gas supply; and

WHEREAS, Nashville has agreed to make the Supporting Calculations available to employees of the TRA Staff, employees of the Consumer Advocate and Frank Creamer (collectively "Authorized Agencies") on the condition that such persons execute this Non-Disclosure Agreement;

NOW, THEREFORE, the undersigned person agrees as follows:

1. The undersigned person is an employee of one of the Authorized Agencies and desires to review the Supporting Calculations solely for the purpose of reviewing Nashville's compliance with the TRA's orders in Docket No. 96-00805; and

2. The undersigned person will keep the Supporting Calculations in a secure place and will not permit them to be seen by any person who is not an employee of one of the Authorized Agencies who has executed a Non-Disclosure Agreement indicating his or her intent to comply with the terms hereof.

3. The undersigned person agrees that prior to the entry of an appropriate protective order he or she will not disclose any information obtained from reviewing the Supporting Calculations orally or in writing to any other person other than another employee of one of the Authorized Agencies who has executed a Non-Disclosure Agreement and that upon the entry of an appropriate protective order he or she will comply with the terms thereof.

4. The undersigned person will not make copies of the Supporting Information or any portion thereof; however, the undersigned person may take notes on the Supporting Information in which event all such notes shall be subject to the terms of this Non-Disclosure Agreement.

K D Waddell
Signature

12/30/97
Date

Piedmont
Natural Gas
Company

Post Office Box 33068
Charlotte, North Carolina 28233

March 31, 1998

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, to Establish a Performance Incentive Plan
Docket No. 96-00805

Dear Mr. Waddell:

I am enclosing for filing in the above captioned proceeding the original and fourteen copies of an Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, for Extension of the Performance Incentive Plan. A check in the amount of $25.00 is enclosed in payment of the filing fee.

I am enclosing an additional copy of the Application that I would appreciate your stamping filed and returning in the enclosed envelope.

Sincerely,

Bill R. Morris

Bill R. Morris
Director of Rates

BRM:kam
Encl.

Before The
Tennessee Regulatory Authority
Nashville, Tennessee

Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company to Establish a Performance Incentive Plan	Docket No. 96-00805

Application For Extension Of Performance Incentive Plan

Nashville Gas Company (Nashville), a division of Piedmont Natural Gas Company, Inc. (Piedmont), hereby respectfully requests the Tennessee Regulatory Authority (Authority) to extend Nashville's previously-approved performance incentive plan (Incentive Plan) on a "permanent" basis or until further order of the Authority. In support of this request, Nashville respectfully shows the following:

I.

Background.

A. On May 31, 1996, the Tennessee Public Service Commission (Commission), the predecessor to the Authority, approved the Incentive Plan for an experimental two year period beginning July 1, 1996. The Incentive Plan approved by the Commission was the result of an agreement between Nashville and the Consumer Advocate and was not opposed by any party. The order approving the Incentive Plan required Nashville and the Authority Staff to recommend a qualified independent consultant to review the progress of the approved Incentive Plan and to annually report the consultant's findings to the Commission. The order also required Nashville to inform the Commission by April 1, 1997, if it wished to continue the Incentive Plan for a second year.

B. On November 27, 1996, Nashville and the Authority Staff submitted for the Authority's approval a contract for Andersen Consulting to review the progress of the Incentive Plan. By order dated January 2, 1997, the Authority determined that the recommendation of the Company and the Staff to employ Andersen Consulting was appropriate and approved the contract dated November 21, 1996 by which Anderson Consulting was to perform its annual reviews.

C. By letter dated March 31, 1997, Nashville informed the Authority that it proposed to continue the plan for a second year without modification. By letter dated April 7, 1997, Associated Valley Industries notified the Authority that it did not object to the Company's request. No other party filed an objection to the Company's request.

D. By a report dated May 1, 1997, Andersen Consulting filed its first year review of the Incentive Plan and recommended that the Incentive Plan be continued for another year without modification. A copy of the May 1, 1997 report is attached to this application as Exhibit A.

E. By order dated June 30, 1997, the Commission authorized Nashville to continue the Incentive Plan for a second year commencing July 1, 1997.

F. By a report dated March 23, 1998, Andersen Consulting filed its second year review of the Incentive Plan and recommended that the Incentive Plan be continued on a "permanent" basis. A copy of the March 23, 1998 report is attached to this Application as Exhibit B.

II.

Incentive Plan Benefits.

A. On August 28, 1997, Nashville submitted its annual report of shared gas cost savings for the first year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit C, showed accumulated first year gains and savings of $1,379,383. Under the Incentive Plan's sharing formulas, $924,554 of this amount accrued to the benefit of Nashville's ratepayers and $454,829 was credited to Nashville's Incentive Plan Account.

B. On March 18, 1998, Nashville submitted its report for the period July 1, 1997 through January 31, 1998 of activity during the second year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit D, showed accumulated gains and savings of $809,156. Under the Incentive Plan's sharing formulas, $611,065 accrued to the benefit of Nashville's ratepayers and $198,091 was credited to Nashville's Incentive Plan Account.

C. As shown above, the Incentive Plan has provided substantial direct financial benefits to ratepayers. In addition, the Incentive Plan has provided other indirect benefits such as avoiding the necessity of annual PGA prudence reviews and has lowered regulatory costs which otherwise would be associated with such proceedings. It can reasonably be expected that these benefits will continue in the future.

III.

Revised Incentive Plan

Attached to this application as Exhibit E is a revised Service Schedule No. 14 setting forth the "permanent" Incentive Plan. This exhibit has been marked to show changes from the existing Incentive Plan. The changes are for the purpose of either (a) converting the Incentive Plan from an experimental plan to a "permanent" plan or (b) to clarify and/or simplify certain language in the existing Incentive Plan tariff. The changes do not change any of the substantive or material provisions of the existing Incentive Plan.

IV.

Request to Eliminate Independent Review

The Incentive Plan agreed to by Nashville and the Consumer Advocate did not call for an independent review of its performance. Nevertheless, because the Incentive Plan was experimental in nature, the Commission determined that an independent review would be appropriate. In each of its reports to the Commission/Authority, the independent consultant reported that the Incentive Plan has provided significant benefits to consumers and recommended that the Incentive Plan be continued. Consistent with the recommendation contained in the Andersen Consulting report dated March 23, 1998, Nashville respectfully submits that there is no longer any need to incur the expense of an independent review. As shown above, the benefits of the Incentive Plan have now been proven. Furthermore, Nashville will continue to submit quarterly and annual reports of the operations of the

Incentive Plan to the Authority and the Consumer Advocate. If those reports should raise questions about the continued operation of the Incentive Plan, the Authority can take appropriate action.

V.

Exhibits

The following exhibits are attached to and incorporated in this application:

Exhibit A -- Report of Andersen Consulting dated May 1, 1997.

Exhibit B -- Report of Andersen Consulting dated March 23, 1998.

Exhibit C -- Annual report of shared gas cost savings for the first year of the Incentive Plan.

Exhibit D -- Report of shared gas cost savings for the period July, 1997 through January, 1998.

Exhibit E -- Revised Service Schedule No. 14.

VI.

Requested Relief:

Nashville respectfully requests the Authority to authorize Nashville to continue to operate under the Incentive Plan, as revised, on a "permanent" basis in such a manner that the Incentive Plan will rollover for an additional plan year on July 1 of each year beginning July 1, 1998 and continuing until the Incentive Plan is either (a) terminated at the end of a plan year by not less than 90 days notice by Nashville to the Authority or (b) the Incentive Plan is modified, amended or terminated by the Authority.

Respectfully submitted, this the 31st day of March, 1998.

Nashville Gas Company, a Division of
Piedmont Natural Gas Company, Inc.

By: ______________________

Thomas E. Skains
Senior Vice President - Gas Supply and Services

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Thomas E. Skains, being first duly sworn, states that he is Senior Vice President - Gas Supply and Services of Piedmont Natural Gas Company, Inc., that he has read the foregoing Petition, that the facts stated therein are true to the best of his knowledge, information and belief and that he has been duly authorized to execute the foregoing Application on behalf of Piedmont Natural Gas Company, Inc.

T E S

Thomas E. Skains

Sworn to and subscribed before me
this the 31st day of March, 1998

Kelly P. Queen

Notary Public

My commission expires:

August 10, 1999

Certificate of Service

I hereby certify that I have this day served a copy of the foregoing document upon each party of record by hand delivery.

This the 31st day of March, 1998.

Bill R. Morris

Bill R. Morris

ANDERSEN CONSULTING

Exhibit A

Incentive Ratemaking

Andersen Consulting LLP
33 West Monroe Street
Chicago, Illinois 60603
(312) 372-7100

May 1, 1997

FILE COPY
RATE DEPT.

Mr. William H. Novak
Utility Rate Division Manager
Energy and Water Section
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Mr. Bill Morris
Piedmont Natural Gas Company
1915 Rexford Rd.
Charlotte, NC 28211

Re: Incentive Ratemaking Review

Dear Hal and Bill:

Please find enclosed the first year review of Nashville Gas Company's performance incentive plan.

We appreciate the opportunity to be of service to the Regulatory Authority, the rate payers of Tennessee, and Nashville Gas Company, a Division of Piedmont Natural Gas. If you have any questions or concerns regarding this proposal, please feel free to contact at (312) 507-5703.

Sincerely,

ANDERSEN CONSULTING LLP

Frank H. Creamer

By

Frank H. Creamer

DB

Nashville Gas Company, a Division of Piedmont Natural Gas Company

First Year Review of

Performance Incentive Plan : July 1, 1996 - January 31, 1997

May 1, 1997

ANDERSEN
CONSULTING

TABLE OF CONTENTS

I – INTRODUCTION

A - PURPOSE

This purpose of this report is to comply with the Tennessee Regulatory Authority (Agency) requirement to review the two-year performance incentive plan that was implemented on July 1, 1996 by Nashville Gas Company (NGC), a Division of Piedmont Natural Gas Company for its Tennessee service territory. This report is Andersen Consulting's first report on the mechanism and analyzes the first seven months of the program.

B - OBJECTIVE

The objective was to determine whether proper incentives are in place and what, if any, further modifications should be made to the program. Accordingly, we reviewed NGC's performance under the performance mechanisms to assess their impact. We then recommended whether the program should be continued for the second year of the program and if so, the plan modifications that we felt were warranted.

This report provides a quantitative analysis where possible, supplemented by a qualitative review including anecdotal comments where appropriate.

C – SCOPE

The scope of our review was limited to the evaluation of the performance of NGC gas purchasing practices for the period July 1, 1996 through January 31, 1997.

D - STUDY APPROACH

The study approach was the same as used in similar reports on gas incentives plans previously submitted to the Tennessee Regulatory Agency, namely to:

- Determine whether the stated business objectives are a reasonable response by NGC to its marketplace and to the needs of its stakeholders
- Determine whether the measures are aligned to support the achievement of the business objectives outlined below, and if not, to determine the appropriate measures

The review was conducted within the context of the results that were expected to be achieved by moving from a prudence review of gas purchases to a program of the performance-based ratemaking mechanisms with a sharing of benefits (and penalties) between ratepayer and shareholder. The mechanisms were proposed to accomplish three primary business objectives:

- Streamline regulation and lower regulatory costs

- Provide an incentive that indexes NGC's business decisions, and hence profits or losses, to how effectively the company performs on all the cost elements of delivering natural gas to its customer classes

- Hold down costs to consumers.

Based on these business objectives, our analysis was designed to answer the following questions:

- Are the measures integrated?

- Are the various measures aligned to the business objectives?
  - Do they target business behaviors?
  - Do they drive the achievement of targeted business results?
  - Do they provide feedback and rewards?
  - Do they measure what should be measured?

- Do the measures meet the needs, and are they aligned with the requirements, of the marketplace?

- Do the measures meet the goals of NGC's stakeholders, i.e., ratepayers, shareholders, personnel, and regulatory entities?

- Are the measures
  - Relevant
  - Sustainable
  - Measurable
  - Reliable
  - Manageable
  - Communicable (visually and visibly)
  - Timely
  - Consistent, and
  - Credible?

- What are the criteria for establishing and evaluating performance measures?

- How do corporate gas purchasing goals cascade down to the remainder of the organization?

- Is goal-setting built into appraisals and reward systems, from the corporate to the individual level?
- Is a goal-sharing process in place; e.g., how are the rewards and penalties shared among stakeholders?
  - How are incentive-based performance measures related to NGC's pay strategies?
  - How is pay linked to performance at NGC?
- Are the measures "changeable"? If a particular measure or index is no longer relevant or if so much fundamental change has occurred that an index is of little value, can the measure or index be changed?

To answer the above questions, we looked for specific examples of performance under each of the mechanisms or, in the absence of examples, the reasons attributed to nonperformance under the mechanism. Our initial approach was modified to include a quantitative assessment in which data and performance were available, supplemented by qualitative analysis and anecdotal comments where appropriate.

E – ORGANIZATION OF THE REPORT

Following this introductory chapter, our review of NGC's Performance Incentive Plan is organized into three additional chapters and an appendix:

Chapter II.	**Summary of Agency Order** - describes the Agency's order establishing the performance incentive plan and summarizes the two approved mechanisms.
Chapter III.	**Findings** - Reviews the two incentive mechanisms and how they have achieved the objectives of the incentive plan, describes NGC's progress in establishing feedback and reward systems and presents a brief overview of other selected utilities with gas procurement incentive plans.
Chapter IV.	**Recommendations** - Presents recommendations for enhancements to NGC's incentive mechanisms.
Appendix	**Case Studies** - Contains interview summaries of selected utilities with gas procurement incentive programs in place.
	Service Schedule - Contains a detailed description of the structure of the Performance Incentive Plan.

II - OVERVIEW OF PERFORMANCE INCENTIVE MECHANISMS

In a similar proceeding on May 12, 1995 in re: *Application of United Cities Gas Company to Establish an Experimental Performance-based Ratemaking Mechanism*, Docket 95-011234 , the Agency expressed the view that the changes that are occurring in the natural gas industry are creating a situation in which the Agency should begin to look to incentive programs and more streamlined regulation to improve efficiency and hold down costs to consumers.

With regards to Nashville Gas Company, on May 9, 1996, in re: *Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. to Establish a Performance Incentive Plan,* , Docket 96-00805, the Agency approved for NGC, effective July 1, 1996, a performance incentive plan. The approval was subject to:

- The company retaining an independent consultant to review the progress of the approved Incentive Plan and to annually report their findings to the Agency
- The Incentive Plan will rollover into a second year upon the request of NGC and the approval of the Agency.

NGC's performance incentive plan is made up of two mechanism: 1) Gas Procurement Incentive Mechanism and 2) Capacity Management Incentive Mechanism.

The two mechanisms approved by the Agency are summarized in the table below and then discussed in more detail in the following text.

Incentive Mechanism		Sharing Arrangement	Performance Indicator
1.	Gas Procurement	50/50	Gains-99% of Index Penalties - 101% of Index
2.	Capacity Management	Sliding scale from 100/0 to 50/50 a)	Demand costs for transportation and storage capacity
	Earnings Cap:	$1.6	million / year

a) NGC share of the associated cost savings is calculated based on the actual capacity demand charges incurred by NGC. The greater the savings, the higher NGC's sharing percentage.

Mechanism 1: Gas Procurement Incentive - The Gas Procurement Incentive Mechanism establishes a predefined benchmark index against which NGC's performance on the commodity cost of gas is compared. The mechanism also provides for the pass-through of gas supply reservation fees, off-systems sales and wholesale interstate sale for resale, and financial instruments/swaps/private contracts.

NGC retains 50% of the savings of the gas purchased below a predefined benchmark. NGC also pays 50% of the costs of the gas purchased above a predefined benchmark. For the purposes of this report, the predefined benchmark is 99% for gains and 101% for penalties. Gains and penalties are determined by indexes (described below). When gas purchases fall between 99% to 101% of these indexes, no gains or penalties are calculated.

Each month NGC compares its total city gate commodity cost of gas to a monthly price index. The monthly price index is a composite price and, at first glance, appears to be quite mathematically challenging. This is due to the index serving as a single price reflecting the weighted price of gas delivered to NGC's city gate, excluding reservation fees. The reader is referred to the service schedule in the Appendix for a more complete summary. When broken down to its simplest components, the index reflects each gas purchase is assigned to one of three procurement categories:

- Gas supplies purchased in the first-of-the-month market which are transported to the city gate under NGC's FT service agreements
- Spot purchases made at the beginning of the month which are delivered to NGC's system using transportation arrangements other than NGC's FT contracts.
- Gas supplies purchased in the daily spot market and delivered to NGC's city gate using either NGC's FT service agreements or non-NGC transportation agreements.

Each of the above gas purchase transactions is then compared in some way to one or more of the prices listed below:

- Inside FERC Gas Market Report - First day of the month published index price for a geographic pricing region
- Gas Daily - First day of the transaction price for the appropriate geographic pricing regions, as adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate

The monthly price index, I, calculates a volumetrically and capacity weighted commodity cost of gas delivered to NGC's city gate.

The index is calculated as follows, followed by brief definitions (see the schedule in the Appendix for more detailed definitions):

$$I=F_f(P_oK_o+P_1K_1+P_cK_c+\ldots P_\alpha K_\alpha)+F_oO+F_dD;$$

where $F_f+F_o+F_d=1$ or 100% ; and

F_f; F_o; F_d = the fraction of the total gas supplies purchased: in the first-of-month market using NGC's FT; in the first-of-month market using non-NGC's FT; and in the daily spot market.

$P_{0,1,c,\ldots,\infty}$ = Inside FERC Gas Market Report price index for the first-of-the-month edition for a geographic pricing region, and adjusted to include the maximum transportation charges and fuel retention under NGC's FT service agreements. Subscripts $_{0,1,c,\ldots,\infty}$ denote different zones on NGC's suppliers' pipelines.

$K_{0,1,c,\ldots,\infty}$ = the portion of NGC's total firm transportation capacity under contract in a geographic pricing region. Subscripts $_{0,1,c,\ldots,\infty}$ are as above.

O = the weighted average of Inside FERC Gas Market Report first-of-month price indices, plus applicable maximum IT rates and fuel retention, as weighted by actual volumes purchased and delivered using non-NGC FT contracts

D = weighted average of daily average index commodity prices taken from Gas Daily and adjusted to include the maximum transportation and fuel retention charges.

Gas supply reservation fees are 100% pass-through with no profit or loss potential. For new contracts, and for renegotiated contracts, bids will be solicited to include a reservation fee.

Off-system sales and sales for resale transactions, less NGC's variable costs, are credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism. To the extent that the total gas commodity cost is outside the dead-band, the gains/losses are shared 50/50 with the ratepayer.

Futures, financial derivative products, storage swaps, etc. also flow through to the commodity gas cost component of the Gas Procurement Incentive Mechanism. To the extent that the total gas commodity cost is outside the dead-band, the gains/losses are shared 50/50 with the ratepayer.

Gas purchases under NGC's existing supply contract on the Tetco system are excluded from the incentive mechanism.

To the extent that NGC renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, NGC would modify the monthly commodity price index to reflect such a discount.

Mechanism 2: Capacity Management Incentive - NGC retains a portion of the revenues generated through the release of firm transportation or storage capacity on a temporary or permanent basis. The sharing ratio is a sliding scale with NGC earning a larger percentage with higher levels of cost savings, as summarized in the table below

Capacity Management Incentive cost savings as a percent of NGCs annual transportation and storage demand costs	Sharing ratios (Customers/NGC)
≤1%	100/0
>1%; ≤2%	90/10
>2%; ≤3%	75/25
>3%	50/50

The purpose of this mechanism is to manage firm transportation capacity on upstream pipelines and storage capacity through marketing unused capacity.

Earnings Cap - NGC's portion of the over-all gains *or* losses cannot exceed $1.6 million annually.

III – FINDINGS

This chapter is arranged in three sections. The first section summarizes NGC's performance during the first seven months of the plan. The second section reviews organizational policies and practices and the third section provides an overview of selected utilities with gas procurement incentive programs.

A - GAS PURCHASES/CAPACITY RELEASE ACTIVITIES

Current Period

Based on a review of NGC's work papers, the performance of the plan during the Current Period – July 1, 1996 through January 31, 1997 - was as follows:

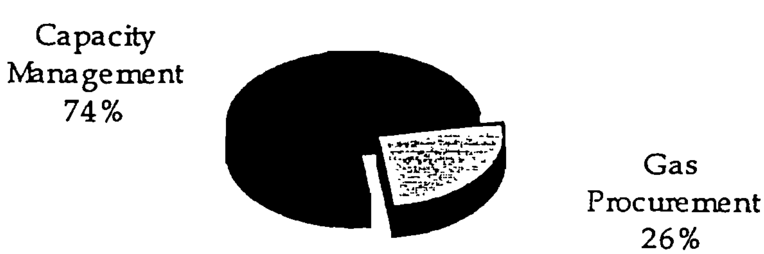
July 1, 1996 through January 31, 1997 (7 months)				
Incentive Mechanism	Sharing Percent (%)	Total Net Revenue ($000)	Total NGC Revenue ($000)	Monthly Avg. Co. Revenue ($000)
1. Gas Procurement	50/50	$ 215[a]	$ 39	$ 5.7
2. Capacity Management	Sliding scale (0-50%)	$ 615	$ 83	$ 12
Total		$ 830	$ 122	$ 17.7
NGC's Gain/Loss Limitation		$1.6 million		

a) Amount includes gains/losses, including the 1% deadband amount. The total gains or losses outside the 1% deadband are $79,000.

Finding: *NGC's net revenue during the 1996-1997 review period which totaled $122,558 was largely attributable to Mechanism 2: Capacity Management, as illustrated below:*

Total Net Revenues –Both Mechanisms

July 1, 1996 - January 31, 1997 (7 mos.)



Finding: *Of the total net revenues for the 1st year of the plan through 1/31/97 ($829,639), $707,081 went to the ratepayer and $122,558 to NGC.*

Finding: *NGC share of gains/losses for the seven month reporting period was less than 10% of the $1.6 million gains/losses cap.*

A summary of the activity in the two utilized mechanisms, Gas Procurement and Capacity Management follows:

Mechanism 1: Gas Procurement Incentive

Finding: *During the 7-month review period, a total of about $215,000 in revenue was "generated" from gas commodity purchases below the monthly price index and margin gains on secondary market sales; however, only $79,000 fell outside of the 1% deadband.*

This occurred during one month, October, 1996. No gains/losses were reported for the remaining six months of the reporting period.

Finding: *Of the $79,000 available for gains/losses, NGC earned $39,000 under the 50/50 sharing formula.*

Finding: *Under the gas procurement mechanism, approximately 70% of the October, 1996 gains of $39,000 was earned due to actual city gate commodity costs and 30% earned on gains on the secondary market sales.*

Finding: *NGC did participate in the futures market during the reporting period, resulting in a small loss which was credited against the gas procurement costs in that period.*

Finding: *The benchmark index excludes gas supply reservation fees. However, we are unaware of any reliable, published sources for market clearing prices for reserving firm gas supplies. Consequently, as a practical matter, we find appropriate the exclusion of reservation fees from the city gate gas supply costs.*

Finding: *Although relatively small dollar gains were earned during the reporting period, the Gas Procurement Mechanism accomplished the objective of providing an incentive that indexes NGC's business decisions, and hence profits or losses, to how effectively the company performs on all the cost elements of delivering natural gas to its customer classes.*

Mechanism 2: Capacity Management Incentive

The capacity performance measure relies essentially on a benchmark of 0. Unlike Mechanism 1, Capacity Management Incentive, which includes transportation release and storage release, is a one-sided mechanism regarding gains/penalties. Generally, only gains can be achieved by participating in the mechanism. Secondly, no benchmark or standard of performance exists regarding either release mechanisms.

Transportation Release

Finding: *The sliding scale sharing ratio of 0/100 to 50/50 for different levels of monthly income meets the relevancy and reward criteria in supporting NGC's reasonable response to the needs of the marketplace and its objective of holding down gas costs to the consumer. Secondly, the Mechanism provides sufficient incentives to encourage this activity, while reflecting the nature and magnitude of the risk.*

Finding: *During the seven month review period, a total of about $615,000 was earned from capacity release and monthly offsystem sales. Of this amount, NGC's share of the gain amounts to $83,223.*

Storage Release

Through the Capacity Management Incentive Mechanism, NGC retains a percent of the revenues generated through the release of firm storage capacity, either leased or owned, on a temporary or permanent basis. The mechanism includes moving gas (storage capacity rights) into and out of storage, storage swaps, and trades. Its objective is to provide the incentive to market unused firm storage capacity and, as a result, more effectively manage NGC's storage assets.

Finding: *No specific storage capacity management activity was reported during the plan period; therefore, no performance gains/losses were reported.*

B - ORGANIZATIONAL POLICIES AND PRACTICES

In addition to reviewing actual NGC activity under the Performance-Based Ratemaking Mechanism, we reviewed NGC's policies and practices in an effort to assess whether the infrastructure is in place to ensure the long-term success of the program.

As noted earlier, the general criteria for successful implementation of performance measures center on the following sequence:

- Performance measures create behavioral expectations through measurement and reward potential, which drives
- Targeted Business Behaviors, which drives
- Achievement of Targeted Business Results, which drives

- Feedback and Rewards, which sustains
- Targeted Business Behaviors.

In addition, as mentioned in the Study Approach section of Chapter I, we looked for changes in behavior and/or culture in support of achieving the business objectives of the incentive plan.

Finding: *At the company level, the Performance-Based Mechanisms accomplished the above general criteria.*

Finding: *At the department level, NGC implemented a feedback and reward system that directly shares company rewards and penalties with the staff responsible through a pay-for-performance program. Therefore, we believe that NGC's gas procurement performance practices will be assisted and supported by a feedback and reward system that prompts individuals to adopt desired behaviors that support business goals and objectives.*

Finding: *NGC has a clearly articulated Gas Price Risk Management Policy setting forth all necessary and appropriate controls in the use of derivative products such as futures, forward contracts, etc. The policy sets loss limits , number of contracts, and duration.*

C - CASE STUDIES

Included in the Appendix is a summary of 10 selected utilities with gas incentive programs operating outside the state of Tennessee. The summary contains a case study of each utility, based on interviews, and a review of each state's filings, and a case summary table, noting the key aspects of each specific incentive plan. The existence or absence of an incentive plan similar to NGC is not, in itself, a confirmation or a indictment of NGC's plan. Instead the case studies demonstrate the various plans used by other utilities operating in other jurisdictions.

Finding: *Five utilities (San Diego Gas & Electric, Southern California Gas, Columbia Gas, National Fuel Gas, and Midwest Gas) use three commonly available indexes for the commodity portion of their plans. A sixth utility, Wisconsin Power & Light uses a single index of performance, Inside FERC.*

Finding: *Generally, gas procurement savings are shared 50/50 and savings from capacity release or off-system sales are shared 10/90 or 20/80.*

Finding: *Program duration ranges from 2 to 4 years. Other program aspects, such as Weightings, Bandwidths, Ceilings, Delivery margins, e.g. the percentage in excess of the benchmark to ensure delivery reliability, Level of participation in the* *futures market, Use of Marketing firms to purchase gas, and Linkage of Corporate performance to individual performance, vary from one utility to another.*

Finding: *NGC's performance incentive plan is generally consistent with industry practices.*

IV -- RECOMMENDATIONS

We offer the following recommendation to the Performance Incentive Plan:

Roll-over the plan for year two of the program without modification. Although only a small amount of gas procurement gains was earned by NGC during the reporting period, a lack of NGC earnings in itself is not sufficient to disallow the rollover of the program for a second year. Secondly, and more important, the program has merit and has provided benefit to NGC's ratepayers.

At the end of the second year, it can be determined if the magnitude of gains is sufficient enough to keep the plan alive. Additionally , with a second year of performance, sufficient information should be available to satisfy the following objectives:

- To demonstrate proof-of-concept
- To provide a learning environment to modify and enhance the mechanism to fit NGC's market environment.

Lastly, at the end of the second year, the structure of the various mechanisms can be examined to determine if changes are warranted , such as:

- Deletion of the 1% deadband
- Revision of the four-tiered capacity release sharing formula
- Provision for NGC to earn an incentive if it renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index.

APPENDIX

Selected PBR Program Details

Company	Mechanism Components: Off-system sales	Storage or pipeline capacity revenue	Assured Delivery Margin	Performance Measures (utility / customer)	Tolerance Band	Effective Date	Program Term (years)	Indices used in commodity benchmark	Use marketing groups	Stated PBR Goals
Atlanta Gas & Light	√			50%/50%	0%	Nov. '95 TN, Sept. '96 GA			√	√
Baltimore Gas & Electric	√	√		capacity release 90%/10%, off-system 20%/80% or 50%/50% if use assets, 50%/50% spot gas	0%	Sept. '96	2	NYMX, *Inside FERC*	√	√
Columbia Gas	√	√		capacity release 10%/90% < 5%, 50%/50% > 5%; 50% off-system and 20% if assets used, 50%/50% spot gas	5% capacity release, 2% spot purchase	Oct. '94	3	NYMX, *Inside FERC*, *Natural Gas Week*, *Gas Daily*		√
Laclede Gas	√	√		capacity release < $1 5MM 10%/90%, <$2 5MM 20%/80%, >$2 5MM 30%/70% / transportation 10%/90% prior to Oct '90 and 20%/80% after Oct '96 / off-system sales 30%/70%	0%	Oct '96	3		√	
Missouri Gas & Energy			4%	50%/50%	6% spot	July '96	3	*Williams Natural Gas Company*, *Inside FERC*	√	
Midwest Gas			5%	50%/50% up to 3% ceiling	3% spot	Nov. '95	2	*BTU Daily*, *Inside FERC*, *Natural Gas Intelligence*		
National Fuel Gas Distribution			0%	50%/50% up to 10% ceiling	0%	Sept. '96	2	NYMX, *Natural Gas Intelligence*, *Inside FERC*		
San Diego Gas & Electric			0%	50%/50% commodity; 5%/95% transport	2% spot	Aug '93	4	*Inside FERC*, *Natural Gas Week*, *Natural Gas Weekly*	√	√
Southern California Gas				50%/50%, no ceiling commodity, 10%/90%, no ceiling storage	4% spot	April '94	3	NYMX, *Natural Gas Intelligence*, *Inside FERC*	√	√
Wisconsin Power & Light	√	√	4%	multi-tiered (50%/50% up to $1 2 mm and 0% after $5.2 mm)	0%	Jan. '95	2	*Inside FERC*	√	

Table Definitions

Off-system sales - does the PBR program include off-system sales under the incentive plan?

Storage or pipeline capacity revenue - is revenue from selling excess storage or pipeline capacity included under the sharing agreement?

Assured Delivery Margin - in the benchmark calculation, how much if any margin is added to the calculated commodity average to allow the utility to purchase gas with a high degree of confidence in delivery reliability?

Performance Measures (utility / customer) - briefly describe the savings arrangement in place for each company?

Tolerance Band - does a dead zone exist, and if so how much, where savings or cost is not shared between the rate payer and utility?

Effective Date - what was the effective date of the PBR program?

Program Term (years) - how long was the program approved to run?

Indices used in commodity benchmark - what sources are used to calculate the benchmark commodity cost?

Use marketing groups - does the utility employ independent companies to assist in procuring necessary gas supply?

Stated PBR Goals - does the utility have stated company, department or individual goals associated with the PBR program?

Atlanta Gas & Chattanooga Gas
Interview & Filing Summary

Interviewees: Steve Gunther, VP - Regulatory Affairs Phone: 404.584.3797
H. Edwin (Ed) Overcast, VP - Corporate Planning & Rates 404.584.3881

Chattanooga Summary: As of November 1, 1995, the Company was allowed to retain 50% of the profit margin from off-system sales and 90% of the losses. The decision was part of a rate case and was not an experimental pilot.

- Chattanooga Gas had originally proposed retaining 50% of the profits but none of the potential losses

- Staff recommended the Company shouldering 100% of the losses and 50% of the gross profit margin

Atlanta Gas Summary: The Company's request for implementing a PBR in off-system sales, with a 50%/50% split was denied by the Commission on September 13, 1996.

- The Company listed several reasons in support of the plan:
    - Provides incentives to maximize off-system transactions to the benefit of shareholders and rate payers
    - Consistent with a national movement toward unbundling and deregulation of gas distribution activities
    - Consistent with revenue sharing incentive plans and mechanisms approved in other states

- The Commission denied the request citing the following factors:
    - The off-system mechanism was not a supply plan issue and therefore should not be addressed in this proceeding
    - The Company's gas supply incentive mechanism is outside the scope of permitted items in a gas supply plan
    - The incentive mechanism is intertwined and interconnected with the AGL Energy Services contract and cannot be dealt with separately

- The Commission concluded by stating that an appropriate incentive plan would share both risk and reward incentives

Baltimore Gas & Electric
Interview and Filing Summary

Interviewee: D. Douglas DeWitt, Director - Gas & Regulatory Planning   Phone: 410.234.5000

Summary: A two year Market Based Ratemaking (MBR) plan became effective September 17, 1996 which included both capacity release, adjusted commodity costs delivered to the city gate and off-system sales.

Key Findings:

- Capacity release revenues are split 90%/10% between the rate payer and Company, respectively

- Off-system sales profits are split 80%/20% between the rate payer and Company, respectively, if company assets are used and 50%/50% if assets are not used

- Adjusted actual commodity cost delivered to the city gate is compared with the City Gate Index benchmark
  - The total commodity cost includes variable transportation costs for both flowing and storage injections and gains/losses from hedging activities
    - Capacity and cost of capacity is calculated as the weighted average of four locations
  - The Company and rate payer equally share in both achieved savings and/or accrued costs in comparison with the benchmark
  - City Gate Index is composite of 3 day average NYMX and the first of month prices published in *Inside FERC*
    - Adjustments are made for existing long term contracts and to reflect withdrawals in winter

- 40% of gas throughput is used by others and not under MBR so MBR impacts 60% of total gas throughput

- The Market Based Ratemaking (MBR) plan replaced the required prudence review of commodity purchases
  - The Commission will continue to perform an audit of BGE's compliance with the mechanism and a "traditional review" of transportation and storage costs
  - The actual commodity cost of gas would not be reviewed by the Commission, as the mechanism makes that function redundant

- Commission approved a two year timetable followed by a review of the MBR plan with a report due at the end of the first year

- The Staff, Company and People's Counsel could not reach agreement on the MBR plan
  - The Company first filed request for MBR in April 1995
  - October 1995, a Hearing Examiner issued a procedural schedule for litigation

    - Litigation continued until July 1996 when a resolution was reached between all parties

- Specific company and department goals exist surrounding the PBR plan
    - "MBR is useless without goals."

- "Prudence reviews are a thing of the past."
    - Audits are more focused on distribution rather than procurement

- The Company has not "lost" to the benchmark in any month since program began

Lessons Learned:

- There is no way to avoid the complexity of the mechanism
    - Gas arriving at the city gate is not homogenous
    - Multiple supply basins and pipes

- Interviewee sees MBR as a stepping stone to allowing LDCs to compete in the city gate market

Columbia Gas (Maryland, Pennsylvania, Kentucky)
Interview & Filing Summary

Interviewed: Scott Phelps, Director - Gas Procurement Phone: 614.460.6263
John Skirtich, Manager - Shared Services 614.460.4207

Summary: CG is operating three year PBR plans in two states and a two year plan in Maryland with staggered effective dates. The programs include spot purchases, capacity release and off-system sales with generally asymmetric savings.

Key Findings:

- Program start dates: MD = Feb. '96, PA = Oct. '94 (capacity release began Feb. '96)

- Proposed PBR in Ohio but it was declined as part of a rate case filing recently

- 3 mechanisms are in place: capacity release, off-system sales and spot purchases
    - Capacity release program
        - Similar to Baltimore Gas in their Maryland jurisdiction (Columbia Gas' property in Maryland is very small)
        - Capacity release carries a very wide tolerance band (between 85% and 115%, there is no savings or penalties)
            - 10% retained/paid outside of band for +/- 5%
            - 50% retained/paid after first 5% (25% retained in MD)
        - Differentiate between market releases and administrative releases
            - Administrative release is defined as those that are completed for Columbia Gas by a marketer
                - Columbia Gas benefits from the release but just paid a vendor to complete the transaction
            - Only market releases are considered in plan
        - Relatively small dollars are retained under capacity releases as hurdle "... is so high and it is hard to beat history"
        - Capacity release started late in PA because the public consumer advocacy group sued (but lost) to stop inclusion of capacity release mechanism
        - Interviewee felt that in general, capacity release is tougher to keep savings from the Commission than off-system sales because there is a perception that capacity release does not require the same level of management action
        - PA negotiated a higher hurdle for year 2 of the contract after the results of year 1 were known

    - Off-system sales incremental margin
        - Split 50% / 50% on those sales which do not use supply assets
        - 20% retained by CG when own transportation assets are utilized because core customers are still paying
        - Most contentious issue is when do not put on bulletin board because have made arrangement with another utility

Ceilings in place on the maximum size of the transaction but though it is not exceeded, the Commission will question why it was not placed on the board

- Spot purchase
    - Benchmark is the composite of the average of the last 3 days' closing price of the month on NYMX and the weighted average of the first day published prices of *Inside FERC, Natural Gas Week* and *Gas Daily*
    - Adjusted actual cost takes daily average of 7 summer months and sums with first week average of winter months
        - Do not use every day winter average because wanted to avoid perverse behavior in attempting to game system as the middle weeks are very volatile in the winter months
    - There is a 2% dead band in PA but none in MD or KY
    - Savings are split 50%/50%

- Programs were all difficult to gain approval and took on average a year to authorize

- All PBR programs were initiated by CG and required discussions with the Commissions
    - KY is the exception as they have been very open to PBR from the beginning
    - KY is asking CG when they plan to request a comprehensive plan to replace the "rifle shot" as interviewee termed their existing program
        - Current PBR does not include achieving proper capacity levels, peak purchases, etc.
    - Felt that Mountaineer Gas is one of the only utilities operating under a comprehensive PBR plan

- Feels that PBR might decline in importance after 3 years possibly as unbundling becomes more prevalent in the marketplace
    - PBR very useful as a stop gap
    - Unbundling and PBR were complementary tools in serving the rate payer

- The PBR program has lead to specific department goals
    - Interviewee is currently writing a request to his supervisors that incentive pay be tied to meeting/exceeding PBR targets
    - Currently have incentive plan but it does not include PBR
    - Respondent was surprised that other utilities operating under PBR did not as a minimum have written specific department goals
    - Executive thought CG was behind in not having incentive pay tied to PBR department goals

- Consolidated gas supply services of the multiple operating companies soon after FERC approval

- SoCal and San Diego programs were both used as models in structuring CG's programs

- Reservation fees are not included in the program

- No financial instruments are being used at this time and not sure if the Commission would allow or not

- All capacity fees flow through to the consumer

Lessons Learned:

- State Commissions differ dramatically in the amount of oversight
  - KY is limited verification
  - PA requires GCR audits even in the PBR arena
  - MD performs a high level review of the numbers submitted
- Success in approving PBR is dependent on individual's personality on the Commission
- Would not want to be the first utility in a state to attempt PBR as the work required drops if act as a follower
- Should not be too aggressive in seeking approval
  - Would not recommend litigation in forcing the Commission's hand, as it will only come back to haunt the company
- Spot purchase program is least significant area of PBR in terms of financial impact
  - Too little money involved
  - Difficult to come to agreement in reconciling benchmark to actuals
- Difficulty in setting benchmarks, not so much which indices to use but where the utility needs to perform to retain savings, it is very subjective right now, ponder if it would be better to freeze rates and let the utility retain a percent of the savings realized if not all of the savings
  - Understands that Mountaineer Gas and Niagara operate under this type of arrangement
- Work very closely with the big marketing groups, especially Tenneco's marketing arm
- Independent audits are not required under any of the current PBRs
- PBR has not reduced the number of management audit
  - Any reduction brought about from the PBR was more than made up for in the attention generated in retaining savings
  - True reduction in audits would require a comprehensive PBR program

Laclede Gas
Filing & Interview Summary

Interviewee: Mike Cline, Mgr. - Rates & Tariffs Phone: 314.342.0500

Summary: Laclede's three year plan was effective October 1, 1996. The incentive is unique in that Laclede's retained savings increase rather than decrease, as a percentage, as greater levels of savings are achieved. The PBR program consists of four mechanisms: capacity release for both transportation and storage, off-system sales, pipeline discounts and gas procurement.

Key Findings:

- Similar to the MGE plan outlined in docket number go-94-318 but with enhanced and expanded scope
    - Similar in that Laclede also has the right to share capacity release revenues and minimize gas supply acquisition costs
    - New features include off-system sales net revenues and firm transportation discounts

- Capacity Release Structure

Capacity Release Revenues	Company Percentage	Customer Percentage
First $1,500,000	10%	90%
$1,500,001 - $2,500,000	20%	80%
Over $2,500,000	30%	70%

- Interstate and Intrastate Firm Transportation Discounts

Firm Transportation Discounts	Company Percentage	Customer Percentage
Discounts negotiated after Dec. 1, '95	10%	90%
Discounts negotiated after Oct. 1, '96	20%	80%

- Purchased Gas Cost
    - If actual cost exceeds benchmark by more than 110%, Laclede is subject to a prudence review
    - The rate payer is refunded any savings in excess of 94% of the difference between actual and the benchmark

- Off-system Marketing Sales
    - 30% Company and 70% Customer
    - Restrictions include:
        - No negative net sales
        - Sales only on "as available" basis
        - No sales to any Laclede marketing affiliates

- Storage reservation is flow through dollar for dollar to rate payers as are all costs outside of commodity cost
- If discounts are not achieved, costs flow through to rate payers and the utility is subject to possible prudence review

- Laclede has not used financial instruments and the plan does not mention the use of financial instruments to hedge against risk

- There are no specific goals or targets within Laclede regarding PBR

- Began negotiations for PBR plan in August of 1995

- Commission had hinted that they were interested in some sort of incentive plan
    - Commission was dissatisfied with prudence reviews
    - Commission had examined incentive rates in other states

- Laclede was also dissatisfied with management audits
    - There was no resistance within Laclede to a PBR

- The Public Council was supportive from the beginning for a PBR plan
    - Missouri is the only commission which was supportive of a PBR program from the outset

Missouri Gas & Energy (MGE)
Interview & Filing Summary

Interviewees: Ted Austin and, Regulatory Affairs Phone: 816.360.5822
Mike Langston, Regulatory Affairs 512.370.8277

Summary: The Missouri Commission approved MGE's gas procurement pilot for a three year test period effective July 1, 1996. The weighted average of several published commodity prices were summed with an additional 4% margin for assured gas delivery. Savings/expenses are split evenly if actual cost is between 94% and 100% or 104% and 110% of the benchmark. Savings greater than 94% flow solely to the rate payer.

Calculations:

Current Cost of Gas = (BCG + SGCC + est. Wyoming Tight Sands volumes)/(est. current month sales volume + sum of est. annual pipeline transportation cost + est. annual storage cost)/est. annual sales volume))

Benchmark Gas Cost = [(.7 x WNG) + (.3 x PEPL)] x 1.04 x purchased monthly volume

Terminology :

BGC = Benchmark Gas Cost (does not include any transportation costs), based on estimated current month values for WNG, PEPL, purchased volumes and any prior month corrections for estimated versus actuals

SGCC = estimated Storage Gas Commodity Cost (positive when withdrawn, calculated as the average weighted cost of gas (including fuel charges) previously injected times the volumes est. to be withdrawn)

WNG= 1st month delivered spot gas price for the *Williams Natural Gas Company* (TX, OK, KS) and published in *Inside FERC*

PEPL = 1st of the month delivered spot gas price for the Panhandle Eastern Pipeline company (TX, OK (mainline)) as published in *Inside FERC* Gas Market Report, and "volumes" are purchased volumes for the month (excluding Wyoming Tight Sands volumes)

Key Findings:

- Initiated creation of incentive program in Feb. '94
- Catalyst for attempting PBR gas procurement program was the acquisition of Missouri properties from Western Resources. Western Resources had begun discussions with the Commission for starting a pilot program

- When Southern Union acquired the Missouri properties, the Commission requested that management design, manage and complete the pilot program originally suggested by Western Resource's management

- There have been no changes in the mechanisms but the method for recognizing the cost of stored gas has been modified
    - Originally, gas ejected from storage was costed at the current price (winter price)
        - It was changed to reflect the average weighted cost of all gas in that specific storage facility

- MGE does not adjust for storage mix, but only considers volumes in costing

<u>Lessons learned:</u>

- Would not agree to monthly reconciliation between estimated and actuals with prior month adjustments
    - Causes unnecessary work due to annual reconciliation between estimated and actual in addition to reconciling the sum of monthly adjustments with actuals
        - Causes unnecessary work load on Gas Accounting Department and increases price volatility because now have to reconcile original projection and monthly adjustments annually
    - In next rate case, they want to include uncollectibles, etc. in gas cost calculation of incentive plan
    - In next rate case, they are requesting allocation of transportation cost by customer class instead of solely volumetric usage
        - A lot of costs are currently billed to transport companies although they are not buying
        - Recognizing customer classes and the reality that they each require a different cost to serve will assist us in moving to unbundling of services

- Respondent felt that the utility's current inability to unbundle services has hindered their competitiveness in serving the large industrial customer group

- The incentive plan has dramatically reduced the resources required for reporting as no prudence reviews on purchasing are now performed.

- Staff audits are performed annually

Midwest Gas (Iowa)
Interview & Filing Summary

Interviewee: Marvin Sorenson, Gas Pricing Strategist Phone: 712.277.7704

Summary: The Iowa Utilities Board approved Midwest Gas' three year pilot effective November 1, 1995. The reference price is a weighted average of the published prices in *BTU Daily, Inside FERC* and *Natural Gas Intelligence*. A tolerance band is in place for both shared savings and costs. The tolerance band above the index is 3.5%, 3% and 2.5% for the three years, respectively. A tolerance band below the index is only in place for year three of the plan and extends to .5%. Savings and costs are shared up to a maximum of 3%.

Key Findings:

- PBR plan as requested by Midwest Gas
  - Start date was November 1, 1995
  - 50% / 50% sharing of first 3% savings/expense with 100% to customer after 3%
  - Midwest will absorb 50% of the first 3% over the benchmark
  - Actual cost index includes storage, transportation and the cost of gas
  - Cost of gas used in benchmark is derived by calculating the weighted average cost of a index (BTU Daily) and two equally weighted long-term indices (*Inside FERC* and *Natural Gas Intelligence*)

- Resistance to PBR
  - The Consumer Advocate objected to the plan citing several factors but the Commission approved the plan
    - Plan could lead to imprudent gas purchasing
    - Reference price is overly complicated and therefore open to manipulation as Midwest Gas could alter production field entitlement
    - Consumers' risk is greater than risk assumed by Midwest Gas

- Decision
  - Commission supported Midwest Gas because:
    - Plan produces just and reasonable rates
    - Consistent with FERC Order 636
    - Addresses the changing regulatory nature of the industry
    - Incentive is directly tied to Midwest Gas' performance and should benefit rate payers
  - Commission approved plan with some modifications
    1. Midwest Gas will be required to use actual volumes rather than entitlements in the benchmark calculation
    2. The Board will conduct semi-annual reviews and not annual reviews as requested by Midwest Gas (actual cost will be compared to benchmark costs every 6 months)

National Fuel Gas Distribution
Filing Summary

Summary: The New York PSC approved a two year plan with an evenly split savings or cost differential up to +/-10% of the benchmark ending September 30, 1998 for spot gas purchases. The benchmark uses a composite of published prices and NYMX. A tolerance zone of +/- 1% is in place.

Key Findings:

- Benchmark Calculation
    - (Monthly Benchmark Unit Cost, Southwest * Actual Monthly Spot Gas Purchases, Southwest) + (Monthly Benchmark Unit cost, City Gate * Actual Monthly Spot Gas Purchases, City Gate)

- Terminology
    - Benchmark Unit Cost = summation of NYMX price, Geographic Basis Differential, the Commodity Cost of Transporting Gas to the city gate from the various purchase points and the Transportation Fuel Component associated with those deliveries
        - NYMX price - simple average of the closing prices for the last three days, including the settlement date, of the particular month's natural gas contract
        - Geographical Basis Differential - references three pooling points
            - Simple average of *Natural Gas Intelligence* and *Inside FERC*
            - Compare the simple average of the published prices with Henry Hub Price
            - Basis differentials are weighted based on the Maximum Daily Entitlement at each of the pooling points
        - Commodity Cost of Transporting Gas - weighted average of the Commodity Cost to deliver from the pooling basins to the receipt point
        - Transportation Fuel Component - calculated in same manner as Commodity Cost of Transporting Gas

- Both fixed price and all long term purchase contracts are excluded from the mechanism

San Diego Gas & Electric (SDG&E)
Interview & Filing Summary

Interviewee: Joseph Vaccaro - Mgr., Performance Based Ratemaking Phone: 619.696.4058

Summary: SDG&E started a 4 year pilot program on August 1, 1993 with the difference to a weighted average index split evenly. A dead band exists between 100% and 102% of index.

Key Findings:

- There are 3 components of the plan but only one will be detailed as relevant to this survey
    1. Core customer base rates
    2. Gas procurement
    3. Generation and dispatch

- The gas procurement component is comprised of two parts
    - Part A is commodity purchases
    - Part B is total delivered cost (to the California/Arizona border)

- Part A
    - Compares actual cost to an index for commodity cost acquisition
        - Index is calculated as the weighted average of published spot prices from four basin/pipeline receipt points as listed in three publications
            - *Inside FERC, Natural Gas Week* and *Natural Gas Weekly*
        - NYMX is not used in the benchmark
        - The benchmark reflects the commodity cost only as all transportation costs are not included in the calculation
    - No margin is added to the index (an index plus a margin of 1.5% to 3% is common among surveyed utilities)
    - If actual is between 100% and 102% of benchmark, all costs flow through to rate payer
        - Commission allowed a non-symmetrical band because of the inherent risk taken by SDG&E with undertaking PBR and the lack of any additional margin being added to the index
    - If actual cost is below 100% or above 102% , the difference is split 50% / 50%

- Part B
    - Compares actual cost to an index for total delivered cost of gas
        - Only transportation costs to the California or Arizona border are included
            - Intra-state transportation is on a tariff with SoCal Gas and is outside the scope of the plan
            - For "as bill" transport not purchased on the spot market, the difference above or below the index is split 95% / 5%, between the rate payer and shareholder, respectively
        - The benchmark reflects the posted maximum firm transportation rate on the pipeline system from the basin receipt point, including fuel usage charge, and reservation and commodity charges at 100% utilization rate

    - The weighted average delivered price index applies a 70% weighting to El Paso and 30% weighting to Transwestern delivered price indices

- A third section of the plan is Other Source Gas
    - Financial instruments used in hedging risk are included, with the difference between the benchmark used in Part A and actual split 50% / 50%
        - A trading floor is in the early phase of being created
    - Off-system sales' profits and losses are split evenly
    - Storage release is being reviewed but is currently not part of the plan

- Specific department and individual goals are in place regarding PBR performance
    - Compensation historically was similar to the majority of the utility industry with salaries set by job grade and pay raises were basically inflation adjustments
    - SDG&E froze salaries and implemented a bonus plan tied to performance with PBR as a key component

- Due to the success of the pilot, the Commission has requested SDG&E to submit a proposal for implementing PBR on a permanent basis.

<u>Lessons Learned:</u>

- Commission approval of the plan is just a beginning
    - Important to recognize that PBR is evolutionary because of the dynamic nature of the industry

- PBR totally eliminated reasonableness reviews, but Company regulatory affairs' personnel work activity was replaced by PBR reporting requirements

- There is no arbitration required as the numbers calculated in procurement by both the Staff and SDG&E have matched up each year creating a significant time savings over the traditional regulatory approval process

Southern California Gas (SoCal)
Interview & Filing Summary

Interviewee: Sim-Cheng Fung, Gas Supply Phone: 213.244.4297

Summary: SoCal's three year PBR plan started April 1, 1994 and consists of two separate elements, gas procurement and gas storage operations for the core class with a tolerance zone between 100% and 104.5% for gas procurement(year 2 drops to 4%). Savings in gas procurement is split evenly and 10% of difference in storage operations are retained/shouldered by the utility.

Key Findings:

- Gas Procurement Incentive
  - The benchmark is based on a combination of published prices in *Natural Gas Intelligence* and *Inside FERC* and the New York Mercantile Exchange (NYMX).
  - Gas Benchmark Reference Calculation
    - 50%((Average of Futures Prices)+(Basis))+(25% IFERC)+(25%NGI)
      - Average of Futures Prices = simple average of daily settlement prices of NYMX
      - Basis = differential between cash price for gas in the regional buying area and the applicable NYMX contract price
      - IFERC = first of the month published index price from *Inside FERC*
      - NGI = first of the month published index price from *Natural Gas Intelligence*

- Storage Incentive
  - Designed to reduce cost of gas by incenting efficient use of injections and withdrawals so as to take maximum advantage of seasonal price variations
  - Operating constraints are in place to assure adequate supply for peak day demands and unplanned outages

- Reservation fees paid to the producer and off-system sales are not included in the plan

- Financial instruments are used to mitigate risk
  - 2 full time people staff the Risk Department
  - The Risk Department utilize swaps, buy futures, and convert fixed to floating obligations to reduce the volatility of the commodity market

- Arbitration has proven to be time consuming
  - Filed reconciliation June 15, 1996, and have not reached agreement to date
  - PBR has resulted in a dramatic decline in management audits

- Reporting
  - Although not required, SoCal sends the Commission monthly updates
  - The Commission will only audit at the mid-point and end of the 3 year pilot

- SoCal does not use estimates in their calculations, instead they wait 60 days for actuals to perform calculations
- SoCal actively utilizes the services of both independent and subsidiary marketing groups to meet gas needs
- There is no ceiling on the savings that can be earned
- The PBR program prompted management to create company, department and now individual performance goals that relate specifically to the PBR program
- 50% of all gas purchases are on the spot market (defined as 30 days or less)

Wisconsin Power & Light (WPL)
Interview & Filing Summary

Interviewee: Dave Shutes, Mgr.-Financial & Economic Modeling Phone: 608.252.3944

Summary: Wisconsin Power & Light operates under the most comprehensive program identified in the national study. WPL's PBR pilot term was approved for a duration of two years ending January 1, 1997 and compared a weighted average of peak day capacity on three delivery points from *Inside FERC* to actual cost. Any profits and or losses from off-system sales, storage and pipeline capacity, fixed costs and activities from the gas futures market are included in the program.

Benchmark Calculation:

[direct gas cost + reliability factor + out of market contracts + fixed cost + return on working capital for stored gas - (use of capacity + use of storage) / est. sales volume]

Key Findings

- WPL is currently in brief with the Commission to extend the pilot
  - The Staff is recommending recalculating all credits to current cost
  - WPL is vigorously opposing incorporating such a recommendation as it would remove all incentive from obtaining further savings
  - WPL is hopeful that the Commission will not accept the recommendation because the Commission recently approved Wisconsin Gas' request for maintaining the same calculations

- WPL set up their program with the goal of encouraging the most efficient management of their overall gas portfolio and not just the effective purchase of gas

- The Field Price Tracking Mechanism uses a weighted average of peak day capacity (not purchases) on 3 delivery points as listed in *Inside FERC*
  - WPL is unique from all utilities interviewed as the only company weighting their benchmark on peak day capacity instead of purchases
  - The benchmark includes fixed costs, storage expenses and storage capital costs

- Off-system sales are included in the PBR

- Profits from storage capacity profits are included in the PBR

- Capacity fees paid to pipeline companies and any profits from selling the rights are also included in the PBR

- WPL utilizes both independent marketing groups and internal resources for procuring gas supply

- WPL actively participates in the futures market to hedge market risk

- Respondent was not aware of any other utility outside of CA which allowed participation in the futures markets
- WPL's PBR plan recognizes both income and expenses associated with the futures market
- WPL has an analyst and assistant tracking the markets full time

WPL earns a declining savings percentage with a maximum upper and lower limit

At least	Less Than	Incentive Rate	Tier's Max. Amt.	Cum. Max. Amt.
$ 0	$1,151,000	50%	$575,000	$ 575,000
$1,151,001	$2,302,000	25%	$287,750	$ 863,250
$2,302,001	$5,179,500	10%	$287,750	$1,151,000
$5,179,501		0%	$ 0	$1,151,000

- The upper/lower limit were set as the value of the carrying cost of, or revenue requirement associated with the forecasted stored gas inventory

Terminology

- Out of market contracts
  - WPL entered into contracts with Northern Natural taking on contracts in Canada prior to implementing the incentive plan
  - The Commission agreed that it would not be fair to include these "Take or Pay" contracts in the incentive plan

- Reliability factor
  - Reviewed 25-30 prior contracts and agreed with the Commission on a reasonable margin over cost to assure delivery

Lessons Learned

- Will request from the Commission authorization to use the same price tracking mechanism for storage as they currently use for purchasing
  - Currently recalculate storage costs annually

- Will request from the Commission the elimination of the sliding scale which decreased the percentage of savings retained by the utility as certain levels were reached
  - The Commission had imposed the sliding scale out of concern that the utility might accept poor customer reliability for achieving short-term savings
    - The utility will argue that any shortage in gas availability would wipe out all savings so that the utility has plenty of incentive not to risk reliability

- When the pilot program expires, the utility could request a 5 to 7 year agreement for continuing PBR
  - A reopening could be triggered if all peer utilities fell outside of collar

Service Schedule

SERVICE SCHEDULE NO. 14

Performance Incentive Plan

APPLICABILITY

The Performance Incentive Plan replaces the current reasonableness or prudence review of Nashville Gas Company's (Nashville) gas purchasing activities overseen by the Commission. The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE

Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company utilizing a graduated sharing formula, with sharing percentages for Nashville ranging between zero and fifty percent.

The Company will have a cap on incentive gains and losses. During the initial plan year, Nashville's overall gains or losses cannot exceed $1.6 million annually. Also as a part of the Performance Incentive Plan, Nashville submitted a Three Year Supply Plan and will obtain additional firm gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin.

GAS PROCUREMENT INCENTIVE MECHANISM

The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs
- Gas Supply Reservation Fees

- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

COMMODITY COSTS

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+\ldots P_m K_m)+F_oO+F_dD\text{; where}$$

$$F_f+F_o+F_d= 1\text{; and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (~~TPG~~) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and

TGP

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1 Gas purchases under Nashville's existing supply contract on the Tetco system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future.[2] The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[3]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The

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2 To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount.

3 Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-

resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	Sharing percentages Nashville/Customers. (Percent)
Less than or equal to 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

DETERMINATION OF SHARED SAVINGS

The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No. 96-00805. Nashville will compute the gain or loss using the approved formulas monthly.

During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in Nashville's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly

gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE COMMISSION

The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC REVIEW

Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized, and the composition of the utility's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Commission Staff.

Exhibit B

Nashville Gas Company, a Division of Piedmont Natural Gas Company

Second Year Review of Performance Incentive Plan: July 1, 1997 – December 31, 1997

ANDERSEN CONSULTING

March 23, 1998

ANDERSEN CONSULTING

Andersen Consulting LLP
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March 23, 1998

Mr. William H. Novak
Utility Rate Division Manager
Energy and Water Section
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Mr. Bill Morris
Piedmont Natural Gas Company
1915 Rexford Rd.
Charlotte, NC 28211

Re: Incentive Ratemaking Review

Dear Hal and Bill.

Please find enclosed the second year review of Nashville Gas Company's performance incentive plan

We appreciate the opportunity to be of service to the Regulatory Authority, the rate payers of Tennessee, and Nashville Gas Company, a Division of Piedmont Natural Gas. If you have any questions or concerns regarding this proposal, please feel free to contact at (312) 507-5703

Sincerely,

ANDERSEN CONSULTING LLP

Frank H. Creamer

By
Frank H. Creamer
DB

Nashville Gas Company, a Division of Piedmont Natural Gas Company

Second Year Review of

Performance Incentive Plan: July 1, 1997 - December 31, 1997

March 23, 1998

ANDERSEN CONSULTING

TABLE OF CONTENTS

I -- INTRODUCTION

A - PURPOSE

This purpose of this report is to comply with the Tennessee Regulatory Authority (Authority) requirement to review the two-year performance incentive plan that was implemented on July 1, 1996 by Nashville Gas Company (NGC), a Division of Piedmont Natural Gas Company for its Tennessee service territory. This report is Andersen Consulting's second report on the mechanism. The report summarizes the first full year of the program, analyzes the first six months of the second year of the program, and makes recommendations regarding permanency of the program.

B - OBJECTIVE

The objective was to determine whether proper incentives are in place and what, if any, further modifications should be made to the program. Accordingly, we reviewed NGC's performance under the performance mechanisms to assess their impact. We then recommended whether the program should be permanent, and the plan modifications, if any, that were warranted.

This report provides a quantitative analysis where possible, supplemented by a qualitative review including anecdotal comments where appropriate.

C -- SCOPE

The scope of our review was limited to the evaluation of the performance of NGC gas purchasing practices for the period July 1, 1997 through December 31, 1997.

D - STUDY APPROACH

The study approach was the same as used in last year's report and in similar reports on gas incentive plans previously submitted to the Tennessee Regulatory Authority, namely to:

- Determine whether the stated business objectives are a reasonable response by NGC to its marketplace and to the needs of its stakeholders

- Determine whether the measures are aligned to support the achievement of the business objectives outlined below, and if not, to determine the appropriate measures

The review was conducted within the context of the results that were expected to be achieved by moving from a prudence review of gas purchases to a program of the performance-based ratemaking mechanisms with a sharing of benefits (and penalties) between ratepayer and shareholder. As noted in last year's report and repeated here, the mechanisms were proposed to accomplish three primary business objectives:

- Streamline regulation and lower regulatory costs

- Provide an incentive that indexes NGC's business decisions, and hence profits or losses, to how effectively the company performs on all the cost elements of delivering natural gas to its customer classes
- Hold down costs to consumers.

Based on these business objectives, our analysis, as was the case in last year's analysis, was designed to answer the following questions:

- Are the measures integrated?
- Are the various measures aligned to the business objectives?
  - Do they target business behaviors?
  - Do they drive the achievement of targeted business results?
  - Do they provide feedback and rewards?
  - Do they measure what should be measured?
- Do the measures meet the needs, and are they aligned with the requirements, of the marketplace?
- Do the measures meet the goals of NGC's stakeholders, i.e., ratepayers, shareholders, personnel, and regulatory entities?
- Are the measures
  - Relevant
  - Sustainable
  - Measurable
  - Reliable
  - Manageable
  - Communicable (visually and visibly)
  - Timely
  - Consistent, and
  - Credible?
- What are the criteria for establishing and evaluating performance measures?
- How does corporate gas purchasing goals cascade down to the remainder of the organization?

- Is goal-setting built into appraisals and reward systems, from the corporate to the individual level?
- Is a goal-sharing process in place; e.g., how are the rewards and penalties shared among stakeholders?
  - How are incentive-based performance measures related to NGC's pay strategies?
  - How is pay linked to performance at NGC?
- Are the measures "changeable"? If a particular measure or index is no longer relevant or if so much fundamental change has occurred that an index is of little value, can the measure or index be changed?

To answer the above questions, we looked for specific examples of performance under each of the mechanisms or, in the absence of examples, the reasons attributed to nonperformance under the mechanism. Our initial approach was modified to include a quantitative assessment in which data and performance were available, supplemented by qualitative analysis and anecdotal comments where appropriate.

E -- ORGANIZATION OF THE REPORT

Following this introductory chapter, our review of NGC's Performance Incentive Plan follows last year's analysis in order to provide consistency, and is organized into three additional chapters and an appendix:

Chapter II. **Summary of Authority Order** - describes the Authority's order establishing the performance incentive plan and summarizes the two approved mechanisms.

Chapter III. **Findings/Conclusions** - Reviews the two incentive mechanisms and how they have achieved the objectives of the incentive plan, describes NGC's progress in establishing feedback and reward systems and presents a brief overview of other selected utilities with gas procurement incentive plans.

Chapter IV. **Recommendations** - Presents recommendations to NGC's incentive mechanisms.

II - OVERVIEW OF PERFORMANCE INCENTIVE MECHANISMS

In a similar proceeding on May 12, 1995 in re: *Application of United Cities Gas Company to Establish an Experimental Performance-based Ratemaking Mechanism*, Docket 95-011234 , the Authority expressed the view that the changes that are occurring in the natural gas industry are creating a situation in which the Authority should begin to look to incentive programs and more streamlined regulation to improve efficiency and hold down costs to consumers.

With regards to Nashville Gas Company, on May 9, 1996, in re: *Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. to Establish a Performance Incentive Plan,* , Docket 96-00805, the Authority approved for NGC, effective July 1, 1996, a performance incentive plan. The approval was subject to:

- The company retaining an independent consultant to review the progress of the approved Incentive Plan and to annually report their findings to the Authority
- The Incentive Plan will rollover into a second year upon the request of NGC and the approval of the Authority.

Subsequently, on March 31, 1997, NGC notified the Authority of its intent to roll-over the Plan for the second year. On June 30, 1997 , the Authority re: *Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. to Establish a Performance Incentive Plan,* Docket 96-00805 approved the incentive plan for another year beginning July 1, 1997, without modifications.

NGC's performance incentive plan is unchanged for the two-year period, and is made up of two mechanisms: 1) Gas Procurement Incentive Mechanism and 2) Capacity Management Incentive Mechanism.

The two mechanisms approved by the Authority are summarized in the table below and then discussed in more detail in the following text.

Incentive Mechanism		Sharing Arrangement	Performance Indicator
1.	Gas Procurement	50/50	Gains-99% of Index Penalties - 101% of Index
2.	Capacity Management	Sliding scale from 100/0 to 50/50 a)	Demand costs for transportation and storage capacity
	Earnings Cap:	$1.6	million / year

a) NGC share of the associated cost savings is calculated based on the actual capacity demand charges incurred by NGC. The lower the demand charges and the greater the savings, the higher NGC's sharing percentage.

Mechanism 1: Gas Procurement Incentive - The Gas Procurement Incentive Mechanism establishes a predefined benchmark index against which NGC's performance on the commodity cost of gas is compared. The mechanism also provides for the pass-through of gas supply reservation fees, and the treatment of off-systems sales, wholesale interstate sales for resale, and financial instruments/swaps/private contracts.

NGC retains 50% of the savings of the gas purchased below a predefined benchmark. NGC also pays 50% of the costs of the gas purchased above a predefined benchmark. For the purposes of this report, the predefined benchmark is 99% for gains and 101% for penalties. Gains and penalties are determined by indexes (described below). When gas purchases fall between 99% to 101% of these indexes, no gains or penalties are calculated.

Each month NGC compares its total city gate commodity cost of gas to a monthly price index. The monthly price index is a composite price and, at first glance, appears to be quite mathematically challenging. This is due to the index serving as a single price reflecting the weighted price of gas delivered to NGC's city gate, excluding reservation fees. The reader is referred to the service schedule in the Appendix for a more complete summary. When broken down to its simplest components, the index reflects each gas purchase and is assigned to one of three procurement categories:

- Gas supplies purchased in the first-of-the-month market which are transported to the city gate under NGC's FT service agreements

- Spot purchases made at the beginning of the month which are delivered to NGC's system using transportation arrangements other than NGC's FT contracts.

- Gas supplies purchased in the daily spot market and delivered to NGC's city gate using either NGC's FT service agreements or non-NGC transportation agreements.

Each of the above gas purchase transactions is then compared in some way to one or more of the prices listed below:

- Inside FERC Gas Market Report - First day of the month published index price for a geographic pricing region

- Gas Daily - First day of the transaction price for the appropriate geographic pricing regions, as adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate

The monthly price index, I, calculates a volumetrically and capacity weighted commodity cost of gas delivered to NGC's city gate.

The index is calculated as follows, followed by brief definitions (see the schedule in the Appendix for more detailed definitions):

$I = F_f(P_oK_o + P_1K_1 + P_cK_c + \ldots P_\alpha K_\alpha) + F_oO + F_dD$;

where $F_f + F_o + F_d = 1$ or 100% ; and

F_f; F_o; F_d = the fraction of the total gas supplies purchased: in the first-of-month market using NGC's FT; in the first-of-month market using non-NGC's FT; and in the daily spot market.

$P_{0,1,c,\ldots,\alpha}$ = Inside FERC Gas Market Report price index for the first-of-the-month edition for a geographic pricing region, and adjusted to include the maximum transportation charges and fuel retention under NGC's FT service agreements. Subscripts $_{0,1,c,\ldots,\alpha}$ denote different zones on NGC's suppliers' pipelines.

$K_{0,1,c,\ldots,\alpha}$ = the portion of NGC's total firm transportation capacity under contract in a geographic pricing region. Subscripts $_{0,1,c,\ldots,\alpha}$ are as above.

O = the weighted average of Inside FERC Gas Market Report first-of-month price indices, plus applicable maximum IT rates and fuel retention, as weighted by actual volumes purchased and delivered using non-NGC FT contracts

D = weighted average of daily average index commodity prices taken from Gas Daily and adjusted to include the maximum transportation and fuel retention charges.

Gas supply reservation fees are 100% pass-through with no profit or loss potential. For new contracts, and for renegotiated contracts, bids will be solicited and the contracts awarded on the basis of the reservation fee bid by suppliers.

Off-system sales and sales for resale transactions, less NGC's variable costs, are credited in part to the Capacity Management Incentive Mechanism and, in part, to the commodity gas cost component of the Gas Procurement Incentive Mechanism. To the extent that the total gas commodity cost is outside the dead-band, the gains/losses are shared 50/50 with the ratepayer.

Futures, financial derivative products, storage swaps, etc. also flow through to the commodity gas cost component of the Gas Procurement Incentive Mechanism. To the extent that the total gas commodity cost is outside the dead-band, the gains/losses are shared 50/50 with the ratepayer.

Gas purchases under NGC's existing supply contract on the Tetco system are excluded from the incentive mechanism.

To the extent that NGC renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, NGC would modify the monthly commodity price index to reflect such a discount.

Mechanism 2: Capacity Management Incentive - NGC retains a portion of the savings generated through the release of firm transportation or storage capacity on a temporary or permanent basis. The sharing ratio is a sliding scale with NGC earning a larger percentage with higher levels of cost savings, as summarized in the table below

Capacity Management Incentive cost savings as a percent of NGC's annual transportation and storage demand costs	Sharing ratios (Customers/NGC)
≤ 1%	100/0
> 1%; ≤ 2%	90/10
> 2%; ≤ 3%	75/25
> 3%	50/50

The purpose of this mechanism is to manage firm transportation capacity on upstream pipelines and storage capacity through marketing unused capacity.

Earnings Cap - NGC's portion of the over-all gains *or* losses cannot exceed $1.6 million annually.

III - FINDINGS

This chapter is arranged in three sections. The first section summarizes NGC's performance during the first full year of the plan (Prior Period) and an analysis of the first six months of the second year of the plan (Current Period). The second section reviews organizational policies and practices and the third section provide an overview of selected utilities with gas procurement incentive programs.

A - GAS PURCHASES/CAPACITY RELEASE ACTIVITIES

Prior Period

Based on a review of NGC's work papers that were available following the publication of our first report on May 1, 1997, the plan performance during the Prior Period -- July 1, 1996 through June 31, 1997 -- was as follows:

July 1, 1996 through June 30, 1997 (12 months)				
Incentive Mechanism	**Sharing Percent (%)**	**Total Net Savings ($000)**	**Total Ratepayer Savings ($000)**	**Total NGC Gains ($000)**
1. Gas Procurement	50/50	$147 a)	$108	$39
2. Capacity Management	Sliding scale (0-50%)	$ 1,232	$817	$416
Total		$ 1,379	$925	$455
NGC's Gain/Loss Limitation	$1,600,000/year			

a) Amount includes gains/losses, including the 1% deadband amount. The total gains or losses outside the 1% deadband are $78,670.

Finding: *Net savings for the first year of the plan totaled $1,379,000, the amount available to be split between the ratepayers and NGC, subject to the 1-% deadband.*

Findings: *Ratepayers "earned "$925,000 in savings during the first full year of the plan or about 67% of the amount available from the sharing mechanism and the amount within the 1-% deadband.*

NGC "earned" $455,000 during the first full year of the plan or about 33% of the amount available from the sharing mechanism and the amount within the 1-% deadband.

Finding: *NGC's share of gains/losses for the first full year of the plan was about 1/3rd of the $1.6 million gains/losses cap.*

Finding: *The information covering the period January 1, 1997 to June 30, 1997 which was received and reviewed subsequent to our report of May 1, 1997 does not change our initial conclusions contained in our original report, namely that NGC's performance under the first year of the incentive plan, together with the organizational policies and practices supporting the plan, provided material benefits to the ratepayer and NGC.*

Secondly, the plan accomplished the objective of providing an incentive that indexes NGC's business decisions, and hence profits or losses, to how effectively the company performs on all the cost elements of delivering natural gas to its customer classes.

Current Period

Based on a review of NGC's work papers, the performance of the plan during the Current Period -- July 1, 1997 through December 31, 1997 - was as follows:

July 1, 1997 through December 31, 1997 (6 months)				
Incentive Mechanism	**Sharing Percent (%)**	**Total Net Savings ($000)**	**Total Ratepayer Savings ($000)**	**Total NGC Gains ($000)**
1. Gas Procurement	50/50	$ 349a)	$ 222	$ 127
2. Capacity Management	Sliding scale (0-50%)	$ 420	$ 376	$ 44
Total		$ 769	$ 598	$ 171
NGC's Gain/Loss Limitation	$1,600,000/year			

a) Amount includes gains/losses, including the 1% deadband amount. The total gains or losses outside the 1% deadband are $254,678.

Finding: *Net savings for the first six months of the 2nd year of the plan totaled $769,000, the amount available to be split between the ratepayers and NGC.*

Findings: *Ratepayers "earned "$598,000 in savings during the Current Period or about 78% of the amount available from the plan.*

NGC "earned" $171,000 during the first full year of the plan or about 22% of the amount available from the plan.

Finding: *NGC's share of gains/losses for the reporting period was less than 11% of the $1.6 million gains/losses cap.*

Finding: *NGC's net gains during the Current Period was largely attributable to Mechanism 1: Gas Procurement, a reversal from the first year of the plan.*

A summary of the activity in the two utilized mechanisms, Gas Procurement and Capacity Management follows:

Mechanism 1: Gas Procurement Incentive

Finding: *NGC produced savings to its ratepayers during the Current Period, a significant increase over the first year of the Plan.*

Finding: *During the 6-month review period, a total of about $349,000 in savings was "generated" from gas commodity purchases below the monthly price index and margin gains on secondary market sales.*

The majority of the savings occurred during August 1997, largely as a result of a 300,000dth purchase in August 1997 at $0.71/dth below the Tennessee Gas Pipeline Zone 1 index, adjusted for FT fuel and transportation. NGC was able to purchase gas at below market by leveraging its storage capacity assets.

Finding: *Of the amount available for gains/losses, NGC earned $127,000 under the 50/50 sharing formula.*

Finding: *NGC did not participate in the futures market during the reporting period.*

Finding: *As noted in our previous report, the benchmark index excludes gas supply reservation fees. However, we continue to be unaware of any reliable, published sources for market clearing prices for reserving firm gas supplies. Consequently, as a practical matter, we continue to find appropriate the exclusion of reservation fees from the monthly index and the city gate gas supply costs.*

Finding: *The Gas Procurement Mechanism accomplished the objective of providing an incentive that indexes NGC's business decisions, and hence profits or losses, to how effectively the company performs on all the cost elements of delivering natural gas to its customer classes.*

Mechanism 2: Capacity Management Incentive

As noted in our previous report, the capacity performance measure relies essentially on a benchmark of 0. Unlike Mechanism 1, Capacity Management Incentive, which includes transportation release and storage release, is a one-sided mechanism regarding gains/penalties. Generally, only gains can be achieved by participating in the mechanism. Secondly, no benchmark or standard of performance exists regarding either release mechanisms.

Transportation Release

Finding: *During the six-month review period, a total of about $420,000 was earned from capacity release and monthly offsystem sales. Of this amount, NGC's share of the gain amounts to $44,000.*

Finding: *The sliding scale sharing ratio of 0/100 to 50/50 for different levels of annual income meets the relevancy and reward criteria in supporting NGC's reasonable response to the needs of the marketplace and its objective of holding down gas costs to the consumer.*

The Mechanism provides sufficient incentives to encourage this activity, while reflecting the nature and magnitude of the risk.

Storage Release

Through the Capacity Management Incentive Mechanism, NGC retains a percent of the savings generated through the release of firm storage capacity, either leased or owned, on a temporary or permanent basis. The mechanism includes moving gas (storage capacity rights) into and out of storage, storage swaps, and trades. Its objective is to provide the incentive to market unused firm storage capacity and, as a result, more effectively manage NGC's storage assets. As noted above in the Mechanism 1: Gas Procurement Incentive Finding, NGC did utilize its storage assets to leverage purchases of natural gas at a price below market price.

Finding: *No specific storage capacity management activity was reported during the plan period; therefore, no performance gains/losses were reported.*

B - ORGANIZATIONAL POLICIES AND PRACTICES

In addition to reviewing actual NGC activity under the Performance-Based Ratemaking Mechanism, we reviewed NGC's policies and practices in an effort to assess whether the infrastructure is in place to ensure the long-term success of the program.

As noted earlier, the general criteria for successful implementation of performance measures center on the following sequence:

- Performance measures create behavioral expectations through measurement and reward potential, which drives
- Targeted Business Behaviors, which drives
- Achievement of Targeted Business Results, which drives
- Feedback and Rewards, which sustains
- Targeted Business Behaviors.

In addition, as mentioned in the Study Approach section of Chapter I, we looked for changes in behavior and/or culture in support of achieving the business objectives of the incentive plan.

Finding: *At the company level, the Performance-Based Mechanisms accomplished the above general criteria.*

Finding: *At the department level, NGC implemented a feedback and reward system that directly shares company rewards and penalties with the staff responsible through a pay-for-performance program. Therefore, we believe that NGC's gas procurement performance practices will be assisted and supported by a feedback and reward system that prompts individuals to adopt desired behaviors that support business goals and objectives.*

Finding: *NGC has a clearly articulated Gas Price Risk Management Policy setting forth all necessary and appropriate controls in the use of derivative products such as futures, forward contracts, etc. The policy sets loss limits , number of contracts, and duration.*

C - CASE STUDIES

Included in last year's report, in the Appendix, was a summary of 10 selected utilities with gas incentive programs operating outside the state of Tennessee. The summary contained a case study of each utility, based on interviews, and a review of each state's filings, and a case summary table, noting the key aspects of each specific incentive plan.

The existence or absence of an incentive plan similar to NGC is not, in itself, a confirmation or an indictment of NGC's plan. Instead the case studies demonstrated the various plans used by other utilities operating in other jurisdictions and that NGC's performance incentive plan was generally consistent with those industry practices.

IV -- RECOMMENDATIONS

We offer the following six recommendations to the Performance Incentive Plan:

1) **Implement a permanent performance based-ratemaking mechanism, based on the program's merits.** The purpose of the two year period of the plan was two-fold:

   - To demonstrate proof-of-concept
   - To provide a learning environment to modify and enhance the mechanism to fit NGC's unique business and organizational environment

   In our judgement, both of these objectives were satisfied. Furthermore, the ratepayers and NGC realized benefits. Equally important, these benefits are expected to be sustainable for the near future.

2) **Rollover the permanent plan automatically each year, unless NGC gives advance notice of its need to change portions of the plan or its intent to withdraw from the plan.** Due to uncertainties in the natural gas marketplace, including the possibility of retail unbundling, the future ability of published indexes to serve as a proxy for market prices, etc., we recommend that NGC have the ability to assess the impact of these changes as it relates to the plan and accordingly provide notice to the Authority.

   The Authority retains, of course, the ability to modify, amend, or terminate the plan.

3) **Retain the employee incentive compensation plan that links rewards with performance to ensure alignment of behavior and risk-taking with results.** NGC's employee incentive compensation plan is, in our judgement, a key element in sustaining the desired behaviors that support the business goals of the program.

4) **Retain the primary features of the plan, without modifications, as summarized below:**

	Incentive Mechanism	Sharing Arrangement	Performance Indicator
1.	Gas Procurement	50/50	Gains-99% of Index Penalties - 101% of Index
2.	Capacity Management	Sliding scale from 100/0 to 50/50 [a]	Demand costs for transportation and storage capacity
	Earnings Cap:	$1.6	million / year

[a] NGC share of the associated cost savings is calculated based on the actual capacity demand charges incurred by NGC The lower the demand charges and the greater the savings, the higher NGC's sharing percentage.

The Gas Procurement Mechanism includes the primary elements of:

- Commodity costs
- Gas Supply Reservation Fees
- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments, both public and private contracts, hedges and swaps

The Capacity Management Mechanism includes the primary elements of:

- Release of Transportation Capacity
- Release of Storage Capacity
- Transportation or storage margin associated with off-system or wholesale sales-for-resale

5) **Retain, without modifications, the "monthly price index" composite formula, as defined in the attached schedule (see Appendix), that serves to compare NGC's total city gate commodity cost of gas to a benchmark amount.** The monthly price index effectively measures how the company performs on all the cost elements of delivering natural gas to its customer classes.

6) **Remove the need for an independent review by a consultant of the permanent plan.** As noted in the report, one objective of moving to a performance based ratemaking plan is to streamline regulation and lower regulatory costs. Although, an independent review was appropriate during the experimental period of the plan, we, in our judgement, believe that an on-going independent review of the permanent plan undermines these objectives.

APPENDIX

SERVICE SCHEDULE NO. 14
Performance Incentive Plan

APPLICABILITY

The Performance Incentive Plan replaces the current reasonableness or prudence review of Nashville Gas Company's (Nashville) gas purchasing activities overseen by the Commission. The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE

Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company utilizing a graduated sharing formula, with sharing percentages for Nashville ranging between zero and fifty percent.

The Company will have a cap on incentive gains and losses. During the initial plan year, Nashville's overall gains or losses cannot exceed $1.6 million annually. Also as a part of the Performance Incentive Plan, Nashville submitted a Three Year Supply Plan and will obtain additional firm gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin.

GAS PROCUREMENT INCENTIVE MECHANISM

The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs
- Gas Supply Reservation Fees

- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

COMMODITY COSTS

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+\ldots P_\infty K_\infty)+F_oO+F_dD; \text{ where}$$

$$F_f+F_o+F_d = 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and

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1 Gas purchases under Nashville's existing supply contract on the Tetco system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future.[2] The commodity index prices will be adjusted to include the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[3]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The

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2 To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with commodity pricing provisions at a discount to the first-of-the-month price index, Nashville would modify the monthly commodity price index to reflect such discount.

3 Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights would be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, would also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville would modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, then there will be no incentive gains or losses. If the actual total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, then the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account elsewhere under the plan. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, it will flow through gains or losses through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-

resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	Sharing percentages Nashville/Customers. (Percent)
Less than or equal to 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

DETERMINATION OF SHARED SAVINGS

The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No. 96-00805. Nashville will compute the gain or loss using the approved formulas monthly.

During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each month during the term of plan, Nashville will compute any gains or losses under the plan. If Nashville earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain. If Nashville incurs a loss, that same IPA will be credited with such loss. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in Nashville's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly

gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE COMMISSION

The Company will file calculations of shared savings and shared costs quarterly with the Commission not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC REVIEW

Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized, and the composition of the utility's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the Commission Staff.

FILE COPY
RATE DEPT.

Exhibit C

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August 28, 1997

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying annual report of shared gas cost savings for the plan year ended June 30, 1997.

As the summary indicates, the accumulated gains and savings under the plan for the plan year total $1,379,383. Of this amount, $924,554 have accrued to the Company's ratepayers. The remaining $454,829 has been credited to the Company's Incentive Plan Account (IPA).

Detailed calculations supporting the amounts shown in the summary for the period July, 1996 through April, 1997 have been previously provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate. Supporting calculations for May, 1997 and June, 1997 are provided in this filing subject to the execution of non-disclosure agreements. As permitted by the provisions of the approved tariff, the Company will file a rate adjustment on or about October 1, 1997 to amortize the collection of the June 30, 1997 IPA balance over the 12 month period beginning November 1, 1997 and ending October 31, 1998.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos

Enclosure

c: L. Vincent Williams, Consumer Advocate
Frank Creamer, Andersen Consulting
Hal Novak, Tennessee Regulatory Authority

Report on Nashville Incentive Plan
July 1996 - June 1997

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1996	$31,685	$0	$31,685	$23,909	$0	$23,909	$55,594	$0	$55,594
Aug	1996	($13,395)	$0	($13,395)	$61,930	$0	$61,930	$48,535	$0	$48,535
Sept	1996	($7,996)	$0	($7,996)	$86,549	$0	$86,549	$78,553	$0	$78,553
Oct	1996	$111,606	$39,335	$72,271	$96,647	$9,468	$87,180	$208,253	$48,802	$159,451
Nov	1996	($4,294)	$0	($4,294)	$233,751	$46,485	$187,266	$229,457	$46,485	$182,972
Dec	1996	$1,652	$0	$1,652	$78,238	$34,046	$44,193	$79,890	$34,046	$45,845
Jan	1997	$95,366	$0	$95,366	$33,991	$16,995	$16,995	$129,357	$16,995	$112,361
Feb	1997	($29,407)	$0	($29,407)	$214,472	$107,236	$107,236	$185,065	$107,236	$77,829
Mar	1997	($13,595)	$0	($13,595)	$245,883	$122,941	$122,941	$232,288	$122,941	$109,346
Apr	1997	($28,081)	$0	($28,081)	$19,077	$9,538	$9,538	($9,004)	$9,538	($18,543)
May	1997	($10,784)	$0	($10,784)	$70,761	$35,380	$35,381	$59,977	$35,380	$24,598
June	1997	$14,608	$0	$14,608	$66,810	$33,405	$33,405	$81,418	$33,405	$48,013
YTD		$147,365	$39,335	$108,030	$1,232,018	$415,495	$816,523	$1,379,383	$454,829	$924,554

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the plan year were based on actual demand costs as adjusted by refunds or surcharges from pipeline and storage suppliers for the plan year. (See Service Schedule No. 14, page 5)

Exhibit D

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March 18, 1998

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying summary of shared gas cost savings for the period July, 1997 through January, 1998. This summary provides the results of activity under the plan for the fiscal quarter ended January, 1998.

As the summary indicates, the accumulated gains and savings under the plan thus far in the plan year total $809,156. Of this amount, $611,065 have accrued to the Company's ratepayers. The remaining $198,091 will be credited to the Company's Incentive Plan Account.

Detailed calculations supporting the amounts shown in the summary have been provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate subject to the execution of non-disclosure agreements.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos
By BKM

Jerry W. Amos

JWA:leh
Enclosure

c: Hal Novak
Frank Creamer, Andersen Consulting
Vincent Williams, Consumer Advocate

Report on Nashville Incentive Plan
July 1997 - January 1998

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1997	($7,269)	$0	($7,269)	$21,101	$0	$21,101	$13,832	$0	$13,832
Aug	1997	$278,151	$123,328	$154,823	$151,044	$1,843	$149,201	$429,195	$125,171	$304,024
Sept	1997	$13,416	$0	$13,416	$68,762	$6,876	$61,886	$82,178	$6,876	$75,302
Oct	1997	$57,431	$4,011	$53,420	$25,825	$2,583	$23,242	$83,256	$6,594	$76,662
Nov	1997	($13,333)	$0	($13,333)	$74,811	$12,598	$62,213	$61,478	$12,598	$48,880
Dec	1997	$20,833	$0	$20,833	$77,947	$19,487	$58,460	$98,780	$19,487	$79,293
Jan	1998	($35,122)	$0	($35,122)	$75,559	$27,365	$48,194	$40,437	$27,365	$13,072
YTD		$314,107	$127,339	$186,768	$495,049	$70,752	$424,297	$809,156	$198,091	$611,065

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the period are based on estimated annual costs for the plan year. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers.
(See Service Schedule No. 14, page 5)

SERVICE SCHEDULE NO. 14
Performance Incentive Plan

APPLICABILITY
The Performance Incentive Plan (the plan) replaces the ~~current~~ reasonableness or prudence review of Nashville Gas Company's (Nashville) or Company) gas purchasing activities overseen by the ~~Commission~~ Tennessee Regulatory Authority (Authority). The plan is designed to provide incentives to Nashville in a manner that will produce rewards for its customers and its shareholders and improvements in Nashville's gas procurement activities. Each plan year will begin July 1. The annual provisions and filings herein would apply to this annual period.

OVERVIEW OF STRUCTURE
Nashville's Performance Incentive Plan is comprised of two interrelated components.

- Gas Procurement Incentive Mechanism
- Capacity Management Incentive Mechanism

The Gas Procurement Incentive Mechanism establishes a predefined benchmark index to which Nashville's commodity cost of gas is compared. It also addresses the recovery of gas supply reservation fees, the treatment of off-system sales and wholesale interstate sale for resale transactions, and the use of financial or private contracts in managing gas costs. The net incentive benefits or costs will be shared between the Company's customers and the Company on a 50% / 50% basis.

The Capacity Management Incentive Mechanism is designed to encourage Nashville to actively market off-peak unutilized transportation and storage capacity on upstream pipelines in the secondary market. The net incentive benefits or costs will be shared between the Company's customers and the Company utilizing a graduated sharing formula, with sharing percentages for Nashville ranging between zero and fifty percent.

The Company ~~will have a cap on incentive gains and losses. During the initial plan year, Nashville's overall gains or losses cannot exceed~~ is subject to a cap on overall incentive gains or losses of $1.6 million annually. ~~Also as a part of~~ In connection with the Performance Incentive Plan, Nashville ~~submitted~~ shall file with the Authority Staff, and update each year a Three Year Supply Plan ~~and~~. Nashville will obtain additional firm ~~gas supply related thereto. Included in the Three Year Supply Plan is support for a capacity reserve margin~~ capacity and/or gas supply pursuant to such plan.

GAS PROCUREMENT INCENTIVE MECHANISM
The Gas Procurement Incentive Mechanism addresses the following areas:

- Commodity Costs

- Gas Supply Reservation Fees
- Off-System Sales and Sale for Resale Transactions
- Use of Financial Instruments or Other Private Contracts

COMMODITY COSTS

Each month Nashville will compare its *total city gate commodity cost of gas*[1] to a benchmark dollar amount. The benchmark gas cost will be computed by multiplying total actual purchase quantities for the month by a price index. The monthly price index is defined as

$$I = F_f(P_0K_0+P_1K_1+P_cK_c+\ldots P_\propto K_\propto)+F_oO+F_dD; \text{ where}$$

$$F_f+F_o+F_d= 1; \text{ and}$$

I = the monthly city gate commodity gas cost index.

F_f = the fraction of gas supplies purchased in the first-of-the-month market which are transported to the city gate under Nashville's FT service agreements.

P = the *Inside FERC Gas Market Report* price index for the first-of-the-month edition for a geographic pricing region, where subscript 0 denotes Tennessee Gas Pipeline (TGP) Rate Zone 0; subscript 1 denotes TGP Rate Zone 1; subscript C denotes Columbia Gas Transmission (CGT), Louisiana, plus applicable transportation and fuel charges in CGT's FT tariff to Rayne, and subscript $\propto$ denotes new incremental firm services to which Nashville may subscribe in the future.[2] The commodity index prices will be adjusted to include

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1 Gas purchases under Nashville's existing supply contract on the Tetco system are excluded from the incentive mechanism. Nashville will continue to recover 100 percent of these costs through its PGA with no profit or loss potential. Extension or replacement of such contract shall be subject to the same competitive bidding procedures that will apply to other firm gas supply agreements. In addition, Nashville's gas procurement incentive mechanism will measure storage gas supplies against the benchmark index during the months such quantities are purchased for injection. For purposes of comparing such gas purchase costs against the monthly city gate index price, Nashville will exclude any commodity costs incurred downstream of the city gate to storage so that Nashville's actual costs and the benchmark index are calculated on the same basis.

2 To the extent that Nashville renegotiates existing reservation fee supply contracts or executes new reservation fee supply contracts with

the appropriate pipeline maximum firm transportation (FT) commodity transportation charges and fuel retention to the city gate under Nashville's FT service agreements.

K = the fraction (relative to total maximum daily contract entitlement) of Nashville's total firm transportation capacity under contract in a geographic pricing region, where the subscripts are as above.[3]

F_o = the fraction of gas supplies purchased in the first-of-the-month spot market which are delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

O = the weighted average of *Inside FERC Gas Market Report* first-of-the-month price indices, plus applicable maximum IT rates and fuel retention, from the source of the gas to the city gate, where the weights are computed based on actual purchases of gas supplies purchased by Nashville and delivered to Nashville's system using transportation arrangements other than Nashville's FT contracts.

F_d = the fraction of gas supplies purchased in the daily spot market.

D = the weighted average of daily average index commodity prices taken from *Gas Daily* for the appropriate geographic pricing regions, where the weights are computed based on actual purchases made during the month. The commodity index prices will be adjusted to include the appropriate maximum transportation commodity charges and fuel retention to the city gate.

If the actual total commodity gas purchase cost in a month is within one percent of the benchmark dollar amount, ~~then~~ there will be no incentive gains or losses. If the actual

---

commodity pricing provisions at a discount to the first-of-the-month price index, Nashville ~~would~~ shall modify the monthly commodity price index to reflect such discount.

3 Because the aggregate maximum daily contract quantities in Nashville's FT contract portfolio vary by month over the course of the year, the weights ~~would~~ will be recalculated each month to reflect actual contract demand quantities for such month. The contract weights, and potentially the price indices used, ~~would~~ will also vary as Nashville renegotiates existing or adds new FT contracts. As new contracts are negotiated, Nashville ~~would~~ shall modify the index to reflect actual contract demand quantities and the commodity price indices appropriate for the supply regions reached by such FT agreements.

total commodity gas purchase cost varies from the benchmark dollar allowance by more than one percent, ~~then~~ the variance in excess of the one percent threshold shall be deemed incentive gains or losses under the plan. Such gains or losses will be shared 50/50 between the Company and the ratepayers.

Gas Supply Reservation Fees

Nashville will continue to recover 100% of gas supply reservation fee costs through its PGA with no profit or loss potential. For new contracts and/or contracts subject to renegotiation during the Plan year, Nashville will solicit bids for gas supply contracts containing a reservation fee.

Off-System Sales And Sale For Resale Transactions

Margin on off-system sales and wholesale sale-for-resale transactions using Nashville's firm transportation and capacity entitlements (the costs of which are recovered from Nashville's ratepayers) shall be credited to the commodity gas cost component of the Gas Procurement Incentive Mechanism and will be shared with ratepayers. Margin on such sales will be defined as the difference between the sales proceeds and the total variable costs incurred by Nashville in connection with the transaction, including transportation and gas costs, taxes, fuel, or other costs. For purposes of gas costs, Nashville will impute such costs for its related supply purchases at the benchmark first-of-the-month or daily index, as appropriate, on the pipeline and in the zone in which the sale takes place. The difference between Nashville's actual costs and such index price is taken into account ~~elsewhere~~ under the ~~plan~~ Gas Procurement Incentive Mechanism. As to transportation costs, Nashville will impute such costs up to the transporting pipeline's maximum interruptible transportation (IT) rate. The difference between the maximum IT rate and Nashville's actual transportation commodity costs will be treated as capacity release margin under the Capacity Management Incentive Mechanism. After deducting the total transaction costs from the sales proceeds, any remaining margin will be credited to commodity gas costs and shared on a 50/50 basis with ratepayers.

Use Of Financial Instruments Or Other Private Contracts

To the extent Nashville uses futures contracts, financial derivative products, storage swap arrangements, or other private agreements to hedge, manage or reduce gas costs, ~~it will flow through~~ any gains or losses will flow through the commodity cost component of the Gas Procurement Incentive Mechanism.

CAPACITY MANAGEMENT INCENTIVE MECHANISM

To the extent Nashville is able to release transportation or storage capacity, or generate transportation or storage margin associated with off-system or wholesale sales-for-resale, the associated cost savings shall be shared by Nashville and customers according to the following sharing formula:

Capacity Management Incentive cost savings as a percent of Nashville's annual transportation and storage demand costs.	Sharing percentages Nashville/Customers. (Percent)
Less than or equal to 1 percent	0/100
Greater than 1 percent but less than or equal to 2 percent	10/90
Greater than 2 percent but less than or equal to 3 percent	25/75
Greater than 3 percent	50/50

The sharing percentages shall be determined based on the actual demand costs incurred by Nashville (exclusive of credits for capacity release) for transportation and storage capacity during the plan year, as such costs may be adjusted due to refunds or surcharges from pipeline and storage suppliers. Any incentive gains or losses resulting from adjustments to the sharing percentages caused by refunds or surcharges shall be recorded in the current Incentive Plan Account (IPA).

DETERMINATION OF SHARED SAVINGS

~~The calculations and recording of incentive gains or losses under the various elements of the Gas Procurement Incentive Mechanism and the Capacity Management Incentive Mechanism shall be performed in accordance with the benchmark formulas approved by the Commission in Docket No. 96-00805. Nashville will compute the gain or loss using the approved formulas monthly.~~

~~During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Such gains or losses will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.~~

Each month during the term of plan, Nashville will compute any gains or losses ~~under~~ in accordance with the plan. If Nashville earns a gain, a separate Incentive Plan Account (IPA) will be debited with such gain If Nashville incurs a loss, that same IPA will be credited with such loss. During a plan year, Nashville will be limited to overall gains or losses totaling $1.6 million. Interest shall be computed on balances in the IPA using the same interest rate and methods as used in Nashville's Actual Cost Adjustment (ACA) account. The offsetting entries to IPA gains or losses will be recorded to income or expense, as appropriate. At its option, however, Nashville may temporarily record any monthly gains in a non-regulatory deferred credit balance sheet account until results for the entire plan year are available.

Gains or losses accruing to the Company under the Plan will form the basis for a rate increment or decrement to be filed and placed into effect separate from any other rate adjustments to recover or refund such amount over a prospective twelve-month period.

Each year, effective November 1, the rates for all customers, excluding interruptible transportation customers who receive no direct benefit from any gas cost reductions resulting from the plan, will be increased or decreased by a separate rate increment or decrement designed to amortize the collection or refund of the June 30 IPA balance over the succeeding twelve month period. The increment or decrement will be established by dividing the June 30 IPA balance by the appropriate volumetric billing determinants for the twelve months ended June 30. During the twelve month amortization period, the amount collected or refunded each month will be computed by multiplying the billed volumetric determinants for such month by the increment or decrement, as applicable. The product will be credited or debited to the IPA, as appropriate. The balance in the IPA will be tracked as a separate collection mechanism.

FILING WITH THE ~~COMMISSION~~ AUTHORITY

The Company will file calculations of shared savings and shared costs quarterly with the ~~Commission~~ Authority not later than 60 days after the end of each interim fiscal quarter and will file an annual report not later than 60 days following the end of each plan year.

PERIODIC ~~REVIEW~~ INDEX REVISIONS

~~Because of the experimental nature of the Performance Incentive Plan, it is anticipated that the indices utilized~~ Because of changes in the natural gas marketplace, the price indices utilized by the Company, and the composition of the ~~utility's~~ Company's purchased gas portfolio may change. The Company shall, within 30 days of identifying a change to a significant component of the mechanism, provide notice of such change to the ~~Commission~~ Authority Staff.

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MAILING ADDRESS
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GREENSBORO, N C 27402

June 11, 1998

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying summary of shared gas cost savings for the period July, 1997 through April 1998. This summary provides the results of activity under the plan for the fiscal quarter ended April 1998.

As the summary indicates, the accumulated gains and savings under the plan thus far in the plan year total $1,254,883. Of this amount, $821,445 have accrued to the Company's ratepayers. The remaining $433,438 will be credited to the Company's Incentive Plan Account.

Detailed calculations supporting the amounts shown in the summary have been provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate subject to the execution of non-disclosure agreements.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos

JWA:leh
Enclosure

c: Hal Novak
Frank Creamer, Andersen Consulting
Vincent Williams, Consumer Advocate

Report on Nashville Incentive Plan
July 1997 - April 1998

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1997	($7,269)	$0	($7,269)	$21,101	$0	$21,101	$13,832	$0	$13,832
Aug	1997	$278,151	$123,328	$154,823	$151,044	$1,815	$149,229	$429,195	$125,143	$304,052
Sept	1997	$13,416	$0	$13,416	$68,762	$6,876	$61,886	$82,178	$6,876	$75,302
Oct	1997	$57,431	$4,011	$53,420	$25,825	$2,583	$23,243	$83,256	$6,594	$76,663
Nov	1997	($13,333)	$0	($13,333)	$74,811	$12,515	$62,296	$61,478	$12,515	$48,963
Dec	1997	$20,833	$0	$20,833	$77,947	$19,487	$58,460	$98,780	$19,487	$79,293
Jan	1998	($35,122)	$0	($35,122)	$75,559	$27,158	$48,401	$40,437	$27,158	$13,279
Feb	1998	$92,055	$18,466	$73,589	$276,138	$138,069	$138,068	$368,193	$156,535	$211,657
Mar	1998	($48,450)	$0	($48,450)	$88,562	$44,281	$44,281	$40,112	$44,281	($4,169)
Apr	1998	($32,277)	$0	($32,277)	$69,700	$34,850	$34,850	$37,423	$34,850	$2,573
YTD		$325,435	$145,805	$179,630	$929,448	$287,633	$641,815	$1,254,883	$433,438	$821,445

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the period are based on estimated annual costs for the plan year. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers. (See Service Schedule No. 14, page 5)

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BEFORE THE TENNESSEE REGULATORY AUTHORITY

REC'D TN REGULATORY AUTH.

NASHVILLE, TENNESSEE

'98 JUN 15 AM 11 23

OFFICE OF THE EXECUTIVE SECRETARY

IN RE: APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS, TO ESTABLISH A PERFORMANCE INCENTIVE PLAN.	)))))	DOCKET NO. 96-00805

REPORT OF THE HEARING OFFICER FROM THE PRE-HEARING HELD JUNE 15, 1998

This matter is before the Tennessee Regulatory Authority ("Authority") pursuant to an Application to Extend the Performance Incentive Plan (the "Application"), filed on April 1, 1998, by Nashville Gas Company, a Division of Piedmont Natural Gas Company ("Nashville Gas"). The Application is intended to extend Nashville Gas' previously approved performance incentive plan until further order of the Authority. A copy of the Application of Nashville Gas is attached hereto as Exhibit A.

A Pre-Hearing Conference was publicly noticed on June 4, 1998, for June 15, 1998 at 10:00 A.M. At the Pre-Hearing Conference no parties presented themselves other than the Applicant. Counsel representing Nashville Gas at the Pre-Hearing Conference was **Brian Larsen, Esq.**, Bass, Berry and Sims, 511 Union Street, Suite 2100, Nashville, TN 37219.

At the time of the Pre-Hearing Conference no other party had sought intervention into this docket, and no parties presented themselves as intervenors at the Pre-Hearing Conference. The Hearing Officer inquired of the Applicant if it knew of any reason to set a procedural schedule for the filing of discovery or testimony in this matter. The Company knew of none. There being no intervenors in this case, the Hearing Officer recommends that the Application of Nashville Gas be brought before the Directors for consideration.

ATTEST:

HEARING OFFICER

Executive Secretary

Before The
Tennessee Regulatory Authority
Nashville, Tennessee

Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company to Establish a Performance Incentive Plan	Docket No. 96-00805

Application For Extension Of Performance Incentive Plan

Nashville Gas Company (Nashville), a division of Piedmont Natural Gas Company, Inc. (Piedmont), hereby respectfully requests the Tennessee Regulatory Authority (Authority) to extend Nashville's previously-approved performance incentive plan (Incentive Plan) on a "permanent" basis or until further order of the Authority. In support of this request, Nashville respectfully shows the following:

I.

Background.

A. On May 31, 1996, the Tennessee Public Service Commission (Commission), the predecessor to the Authority, approved the Incentive Plan for an experimental two year period beginning July 1, 1996. The Incentive Plan approved by the Commission was the result of an agreement between Nashville and the Consumer Advocate and was not opposed by any party. The order approving the Incentive Plan required Nashville and the Authority Staff to recommend a qualified independent consultant to review the progress of the approved Incentive Plan and to annually report the consultant's findings to the Commission. The order also required Nashville to inform the Commission by April 1, 1997, if it wished to continue the Incentive Plan for a second year.

B. On November 27, 1996, Nashville and the Authority Staff submitted for the Authority's approval a contract for Andersen Consulting to review the progress of the Incentive Plan. By order dated January 2, 1997, the Authority determined that the recommendation of the Company and the Staff to employ Andersen Consulting was appropriate and approved the contract dated November 21, 1996 by which Anderson Consulting was to perform its annual reviews.

Exhibit A

C. By letter dated March 31, 1997, Nashville informed the Authority that it proposed to continue the plan for a second year without modification. By letter dated April 7, 1997, Associated Valley Industries notified the Authority that it did not object to the Company's request. No other party filed an objection to the Company's request.

D. By a report dated May 1, 1997, Andersen Consulting filed its first year review of the Incentive Plan and recommended that the Incentive Plan be continued for another year without modification. A copy of the May 1, 1997 report is attached to this application as Exhibit A.

E. By order dated June 30, 1997, the Commission authorized Nashville to continue the Incentive Plan for a second year commencing July 1, 1997.

F. By a report dated March 23, 1998, Andersen Consulting filed its second year review of the Incentive Plan and recommended that the Incentive Plan be continued on a "permanent" basis. A copy of the March 23, 1998 report is attached to this Application as Exhibit B.

II.

Incentive Plan Benefits.

A. On August 28, 1997, Nashville submitted its annual report of shared gas cost savings for the first year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit C, showed accumulated first year gains and savings of $1,379,383. Under the Incentive Plan's sharing formulas, $924,554 of this amount accrued to the benefit of Nashville's ratepayers and $454,829 was credited to Nashville's Incentive Plan Account.

B. On March 18, 1998, Nashville submitted its report for the period July 1, 1997 through January 31, 1998 of activity during the second year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit D, showed accumulated gains and savings of $809,156. Under the Incentive Plan's sharing formulas, $611,065 accrued to the benefit of Nashville's ratepayers and $198,091 was credited to Nashville's Incentive Plan Account.

C. As shown above, the Incentive Plan has provided substantial direct financial benefits to ratepayers. In addition, the Incentive Plan has provided other indirect benefits such as avoiding the necessity of annual PGA prudence reviews and has lowered regulatory costs which otherwise would be associated with such proceedings. It can reasonably be expected that these benefits will continue in the future.

III.

Revised Incentive Plan

Attached to this application as Exhibit E is a revised Service Schedule No. 14 setting forth the "permanent" Incentive Plan. This exhibit has been marked to show changes from the existing Incentive Plan. The changes are for the purpose of either (a) converting the Incentive Plan from an experimental plan to a "permanent" plan or (b) to clarify and/or simplify certain language in the existing Incentive Plan tariff. The changes do not change any of the substantive or material provisions of the existing Incentive Plan.

IV.

Request to Eliminate Independent Review

The Incentive Plan agreed to by Nashville and the Consumer Advocate did not call for an independent review of its performance. Nevertheless, because the Incentive Plan was experimental in nature, the Commission determined that an independent review would be appropriate. In each of its reports to the Commission/Authority, the independent consultant reported that the Incentive Plan has provided significant benefits to consumers and recommended that the Incentive Plan be continued. Consistent with the recommendation contained in the Andersen Consulting report dated March 23, 1998, Nashville respectfully submits that there is no longer any need to incur the expense of an independent review. As shown above, the benefits of the Incentive Plan have now been proven. Furthermore, Nashville will continue to submit quarterly and annual reports of the operations of the

Incentive Plan to the Authority and the Consumer Advocate. If those reports should raise questions about the continued operation of the Incentive Plan, the Authority can take appropriate action.

V.

Exhibits

The following exhibits are attached to and incorporated in this application:

Exhibit A -- Report of Andersen Consulting dated May 1, 1997.

Exhibit B -- Report of Andersen Consulting dated March 23, 1998.

Exhibit C -- Annual report of shared gas cost savings for the first year of the Incentive Plan.

Exhibit D -- Report of shared gas cost savings for the period July, 1997 through January, 1998.

Exhibit E -- Revised Service Schedule No. 14.

VI.

Requested Relief.

Nashville respectfully requests the Authority to authorize Nashville to continue to operate under the Incentive Plan, as revised, on a "permanent" basis in such a manner that the Incentive Plan will rollover for an additional plan year on July 1 of each year beginning July 1, 1998 and continuing until the Incentive Plan is either (a) terminated at the end of a plan year by not less than 90 days notice by Nashville to the Authority or (b) the Incentive Plan is modified, amended or terminated by the Authority.

Respectfully submitted, this the 31st day of March, 1998.

Nashville Gas Company, a Division of
Piedmont Natural Gas Company, Inc.

By: ______________________
Thomas E. Skains
Senior Vice President - Gas Supply and Services

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Thomas E. Skains, being first duly sworn, states that he is Senior Vice President - Gas Supply and Services of Piedmont Natural Gas Company, Inc., that he has read the foregoing Petition, that the facts stated therein are true to the best of his knowledge, information and belief and that he has been duly authorized to execute the foregoing Application on behalf of Piedmont Natural Gas Company, Inc.

Thomas E. Skains

Sworn to and subscribed before me
this the 31st day of March, 1998

Kelly P. Queen
Notary Public

My commission expires:

August 10, 1999

Certificate of Service

I hereby certify that I have this day served a copy of the foregoing document upon each party of record by hand delivery.

This the 31st day of March, 1998.

Bill R. Morris

Bill R. Morris

AMOS, JEFFRIES & ROBINSON, L.L.P.
ATTORNEYS AND COUNSELLORS AT LAW
1230 RENAISSANCE PLAZA
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P.O. BOX 787
GREENSBORO, N C 27402

SHW
WFC
TEC
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8-10-98

August 10, 1998

Mr. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Nashville Gas Company, Docket No. 96-00805

Dear Mr. Waddell:

In accordance with the reporting provisions of Service Schedule No. 14, Performance Incentive Plan, as approved in the above captioned docket, Nashville Gas Company (the "Company") submits the accompanying annual report of shared gas cost savings for the plan year ended June 30, 1998.

As the summary indicates, the accumulated gains and savings under the plan for the plan year total $1,340,957. Of this amount, $832,300 have accrued to the Company's ratepayers. The remaining $508,657 will be credited to the Company's Incentive Plan Account (IPA).

Detailed calculations supporting the amounts shown in the summary for the period July 1997 through April 1998 have been previously provided to the Tennessee Regulatory Authority Staff, the consulting firm engaged to review the Plan, and the Consumer Advocate. Supporting calculations for May 1998 and June 1998 are provided in this filing subject to the execution of non-disclosure agreements. As permitted by the provisions of the approved tariff, the Company will file a rate adjustment on or about October 1, 1998, to amortize the collection of the June 30, 1998 IPA balance over the 12 month period beginning November 1, 1998, and ending October 31, 1999.

I am enclosing one additional copy of the summary that I would appreciate your stamping "filed" and returning to me in the enclosed envelope.

Sincerely,

Jerry W. Amos

JWA:leh
Enclosures

c: L. Vincent Williams, Consumer Advocate
Frank Creamer, Andersen Consulting
Hal Novak, Tennessee Regulatory Authority

Report on Nashville Incentive Plan
July 1997 - June 1998

Month	Year	Gas Procurement Incentive Mechanism Gain/(Loss) 1/	Nashville GPI Sharing Gain/(Loss) 2/	Ratepayer GPI Sharing Gain/(Loss)	Capacity Management Incentive Mechanism Gain/(Loss)	Nashville CMI Sharing Gain/(Loss) 3/	Ratepayer CMI Sharing Gain/(Loss) 3/	Total Gain/(Loss)	Total Nashville Gain/(Loss)	Total Ratepayer Gain/(Loss)
July	1997	($7,269)	$0	($7,269)	$21,101	$0	$21,101	$13,832	$0	$13,832
Aug	1997	$278,151	$123,328	$154,823	$151,044	$3,864	$147,180	$429,195	$127,192	$302,003
Sept	1997	$13,416	$0	$13,416	$68,762	$6,876	$61,886	$82,178	$6,876	$75,302
Oct	1997	$57,431	$4,011	$53,420	$25,825	$2,583	$23,243	$83,256	$6,594	$76,663
Nov	1997	($13,333)	$0	($13,333)	$74,811	$18,660	$56,150	$61,478	$18,660	$42,817
Dec	1997	$20,833	$0	$20,833	$77,947	$24,229	$53,718	$98,780	$24,229	$74,551
Jan	1998	($35,122)	$0	($35,122)	$75,559	$37,779	$37,779	$40,437	$37,779	$2,657
Feb	1998	$92,055	$18,466	$73,589	$276,138	$138,069	$138,068	$368,193	$156,535	$211,657
Mar	1998	($48,450)	$0	($48,450)	$91,562	$45,781	$45,781	$43,112	$45,781	($2,669)
Apr	1998	($32,277)	$0	($32,277)	$69,700	$34,850	$34,850	$37,423	$34,850	$2,573
May	1998	($22,333)	$0	($22,333)	$13,707	$6,854	$6,854	($8,626)	$6,854	($15,479)
June	1998	$5,085	$0	$5,085	$86,615	$43,307	$43,308	$91,700	$43,307	$48,393
YTD		$308,187	$145,805	$162,382	$1,032,770	$362,852	$669,918	$1,340,957	$508,657	$832,300

1/The monthly gain or loss set forth in this column reflects total gains or losses calculated under the gas procurement mechanism, including gains or losses within the one percent deadband.

2/Nashville GPI sharing reflects 50% of gains or losses calculated under the gas procurement mechanism after application of the one percent monthly deadband.

3/Nashville sharing percentages range from 0% (Up to 1% annual demand savings), to 10% (1-2% savings), to 25% (2-3% savings), and to 50% (> 3% savings). Total capacity demand costs for the period are based on estimated annual costs for the plan year. These sharing amounts shall be adjusted based on the actual demand costs incurred, taking into account refunds or surcharges from pipeline and storage suppliers.
(See Service Schedule No. 14, page 5)

PROTECTED MATERIALS REMOVED

C. OFFICERS
DIRECTORS

BEFORE THE TENNESSEE REGULATORY AUTHORITY AT

NASHVILLE, TENNESSEE

October 22, 1998

IN RE: APPLICATION OF NASHVILLE GAS COMPANY TO ESTABLISH A PERFORMANCE INCENTIVE PLAN	)))	DOCKET NO. 96-00805

ORDER ADOPTING THE REPORT AND RECOMMENDATION OF HEARING OFFICER FROM THE PRE-HEARING CONFERENCE HELD JUNE 15, 1998

This matter came before the Tennessee Regulatory Authority (the "Authority") for consideration of the Report and Recommendation of the Hearing Officer, attached as Exhibit A, from the Pre-Hearing Conference held in the above captioned matter on June 15, 1998. This Report and Recommendation was submitted for the consideration of the Authority by the Hearing Officer, Dennis McNamee. This proceeding originated pursuant to an Application to Extend the Performance Incentive Plan (the "Application"), filed on April 1, 1998, by Nashville Gas Company, a Division of Piedmont Natural Gas Company ("Nashville Gas"). The Application is intended to extend Nashville Gas' previously approved performance incentive plan until further order of the Authority.

The Report and Recommendation of the Hearing Officer was considered by the Directors at a regularly scheduled Authority Conference on June 30, 1998. The Hearing Officer reported to the Directors that the Pre-Hearing Conference was brief. There were no matters to be discussed at the Pre-Hearing Conference. There were no intervenors prior to the Pre-Hearing Conference and no intervenors made themselves known at the Pre-Hearing

Conference. The Hearing Officer recommended the incentive plan move forward for deliberation.

After reviewing the Report and Recommendation of the Hearing Officer, as well as appropriate portions of the record, the Directors determined unanimously that the Report and Recommendation of the Hearing Officer should be approved and adopted.

IT IS THEREFORE ORDERED THAT:

1. The Report and Recommendation of the Hearing Officer from the Pre-Hearing Conference held on June 15, 1998, attached as Exhibit A, is approved and is incorporated as if fully rewritten herein; and

2. Any Party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from and after the date of this Order

CHAIRMAN

DIRECTOR

DIRECTOR

ATTEST:

EXECUTIVE SECRETARY

Before The
Tennessee Regulatory Authority
Nashville, Tennessee

Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company to Establish a Performance Incentive Plan)	Docket No. 96-00805

Application For Extension Of Performance Incentive Plan

Nashville Gas Company (Nashville), a division of Piedmont Natural Gas Company, Inc. (Piedmont), hereby respectfully requests the Tennessee Regulatory Authority (Authority) to extend Nashville's previously-approved performance incentive plan (Incentive Plan) on a "permanent" basis or until further order of the Authority. In support of this request, Nashville respectfully shows the following:

I.

Background.

A. On May 31, 1996, the Tennessee Public Service Commission (Commission), the predecessor to the Authority, approved the Incentive Plan for an experimental two year period beginning July 1, 1996. The Incentive Plan approved by the Commission was the result of an agreement between Nashville and the Consumer Advocate and was not opposed by any party. The order approving the Incentive Plan required Nashville and the Authority Staff to recommend a qualified independent consultant to review the progress of the approved Incentive Plan and to annually report the consultant's findings to the Commission. The order also required Nashville to inform the Commission by April 1, 1997, if it wished to continue the Incentive Plan for a second year.

B. On November 27, 1996, Nashville and the Authority Staff submitted for the Authority's approval a contract for Andersen Consulting to review the progress of the Incentive Plan. By order dated January 2, 1997, the Authority determined that the recommendation of the Company and the Staff to employ Andersen Consulting was appropriate and approved the contract dated November 21, 1996 by which Anderson Consulting was to perform its annual reviews.

Exhibit A

C. By letter dated March 31, 1997, Nashville informed the Authority that it proposed to continue the plan for a second year without modification. By letter dated April 7, 1997, Associated Valley Industries notified the Authority that it did not object to the Company's request. No other party filed an objection to the Company's request.

D. By a report dated May 1, 1997, Andersen Consulting filed its first year review of the Incentive Plan and recommended that the Incentive Plan be continued for another year without modification. A copy of the May 1, 1997 report is attached to this application as Exhibit A.

E. By order dated June 30, 1997, the Commission authorized Nashville to continue the Incentive Plan for a second year commencing July 1, 1997.

F. By a report dated March 23, 1998, Andersen Consulting filed its second year review of the Incentive Plan and recommended that the Incentive Plan be continued on a "permanent" basis. A copy of the March 23, 1998 report is attached to this Application as Exhibit B.

II.

Incentive Plan Benefits.

A. On August 28, 1997, Nashville submitted its annual report of shared gas cost savings for the first year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit C, showed accumulated first year gains and savings of $1,379,383. Under the Incentive Plan's sharing formulas, $924,554 of this amount accrued to the benefit of Nashville's ratepayers and $454,829 was credited to Nashville's Incentive Plan Account.

B. On March 18, 1998, Nashville submitted its report for the period July 1, 1997 through January 31, 1998 of activity during the second year of the Incentive Plan. This report, a copy of which is attached to this application as Exhibit D, showed accumulated gains and savings of $809,156. Under the Incentive Plan's sharing formulas, $611,065 accrued to the benefit of Nashville's ratepayers and $198,091 was credited to Nashville's Incentive Plan Account.

C. As shown above, the Incentive Plan has provided substantial direct financial benefits to ratepayers. In addition, the Incentive Plan has provided other indirect benefits such as avoiding the necessity of annual PGA prudence reviews and has lowered regulatory costs which otherwise would be associated with such proceedings. It can reasonably be expected that these benefits will continue in the future.

III.

Revised Incentive Plan

Attached to this application as Exhibit E is a revised Service Schedule No. 14 setting forth the "permanent" Incentive Plan. This exhibit has been marked to show changes from the existing Incentive Plan. The changes are for the purpose of either (a) converting the Incentive Plan from an experimental plan to a "permanent" plan or (b) to clarify and/or simplify certain language in the existing Incentive Plan tariff. The changes do not change any of the substantive or material provisions of the existing Incentive Plan.

IV.

Request to Eliminate Independent Review

The Incentive Plan agreed to by Nashville and the Consumer Advocate did not call for an independent review of its performance. Nevertheless, because the Incentive Plan was experimental in nature, the Commission determined that an independent review would be appropriate. In each of its reports to the Commission/Authority, the independent consultant reported that the Incentive Plan has provided significant benefits to consumers and recommended that the Incentive Plan be continued. Consistent with the recommendation contained in the Andersen Consulting report dated March 23, 1998, Nashville respectfully submits that there is no longer any need to incur the expense of an independent review. As shown above, the benefits of the Incentive Plan have now been proven. Furthermore, Nashville will continue to submit quarterly and annual reports of the operations of the

Incentive Plan to the Authority and the Consumer Advocate. If those reports should raise questions about the continued operation of the Incentive Plan, the Authority can take appropriate action.

V.

Exhibits

The following exhibits are attached to and incorporated in this application:

Exhibit A -- Report of Andersen Consulting dated May 1, 1997.

Exhibit B -- Report of Andersen Consulting dated March 23, 1998.

Exhibit C -- Annual report of shared gas cost savings for the first year of the Incentive Plan.

Exhibit D -- Report of shared gas cost savings for the period July, 1997 through January, 1998.

Exhibit E -- Revised Service Schedule No. 14.

VI.

Requested Relief.

Nashville respectfully requests the Authority to authorize Nashville to continue to operate under the Incentive Plan, as revised, on a "permanent" basis in such a manner that the Incentive Plan will rollover for an additional plan year on July 1 of each year beginning July 1, 1998 and continuing until the Incentive Plan is either (a) terminated at the end of a plan year by not less than 90 days notice by Nashville to the Authority or (b) the Incentive Plan is modified, amended or terminated by the Authority.

Respectfully submitted, this the 31st day of March, 1998.

Nashville Gas Company, a Division of
Piedmont Natural Gas Company, Inc.

By: ______________________

Thomas E. Skains
Senior Vice President - Gas Supply and Services

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

Thomas E. Skains, being first duly sworn, states that he is Senior Vice President - Gas Supply and Services of Piedmont Natural Gas Company, Inc., that he has read the foregoing Petition, that the facts stated therein are true to the best of his knowledge, information and belief and that he has been duly authorized to execute the foregoing Application on behalf of Piedmont Natural Gas Company, Inc.

T E Sk

Thomas E. Skains

Sworn to and subscribed before me
this the 31st day of March, 1998

Kelley P. Queen

Notary Public

My commission expires:

August 10, 1999

Certificate of Service

I hereby certify that I have this day served a copy of the foregoing document upon each party of record by hand delivery.

This the 31st day of March, 1998.

Bill R. Morris

Bill R. Morris

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

IN RE: APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS, TO ESTABLISH A PERFORMANCE INCENTIVE PLAN.	)))))	DOCKET NO.: 96-00805

REPORT OF THE HEARING OFFICER FROM THE PRE-HEARING HELD JUNE 15, 1998

This matter is before the Tennessee Regulatory Authority ("Authority") pursuant to an Application to Extend the Performance Incentive Plan (the "Application"), filed on April 1, 1998, by Nashville Gas Company, a Division of Piedmont Natural Gas Company ("Nashville Gas"). The Application is intended to extend Nashville Gas' previously approved performance incentive plan until further order of the Authority. A copy of the Application of Nashville Gas is attached hereto as Exhibit A.

A Pre-Hearing Conference was publicly noticed on June 4, 1998, for June 15, 1998 at 10:00 A.M. At the Pre-Hearing Conference no parties presented themselves other than the Applicant. Counsel representing Nashville Gas at the Pre-Hearing Conference was **Brian Larsen, Esq.**, Bass, Berry and Sims, 511 Union Street, Suite 2100, Nashville, TN 37219.

At the time of the Pre-Hearing Conference no other party had sought intervention into this docket, and no parties presented themselves as intervenors at the Pre-Hearing Conference. The Hearing Officer inquired of the Applicant if it knew of any reason to set a procedural schedule for the filing of discovery or testimony in this matter. The Company knew of none. There being no

Exhibit A

intervenors in this case, the Hearing Officer recommends that the Application of Nashville Gas be brought before the Directors for consideration

HEARING OFFICER

ATTEST:

Executive Secretary

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

March 11, 1999

IN RE:	)	
	)	
APPLICATION OF NASHVILLE GAS COMPANY,	)	
A DIVISION OF PIEDMONT NATURAL GAS	)	**DOCKET NO. 96-00805**
COMPANY, TO ESTABLISH A PERFORMANCE	)	
INCENTIVE PLAN	)	

ORDER APPROVING PERFORMANCE INCENTIVE PLAN

On August 18, 1998, this matter came before the Tennessee Regulatory Authority (hereafter the "Authority" or "TRA") for consideration of the Application of Nashville Gas Company (hereafter "Nashville" or "Company"), a division of Piedmont Natural Gas Company, to extend its previously-approved Performance Incentive Plan (hereafter the "Incentive Plan") on a permanent basis or until further order of the Authority. The Company also proposed to revise the Incentive Plan to clarify and/or simplify certain language in a manner that does not change any of its substantive or material provisions. In addition, the Company proposed to eliminate the requirement for an independent annual review.

I. BACKGROUND

On May 31, 1996, the Tennessee Public Service Commission (hereafter the "TPSC"), the predecessor to the Authority, issued an order approving the Incentive Plan for an experimental two-year period, beginning July 1, 1996. The Incentive Plan replaces the reasonableness or prudence review of Nashville's gas purchasing activities overseen by the Authority and is designed to produce rewards for Nashville's customers and its shareholders and to produce improvements in Nashville's gas procurement activities. The Incentive Plan approved by the TPSC was the result of an agreement between Nashville and the Consumer Advocate Division of the Office of the Tennessee Attorney General (hereafter "Consumer Advocate") and was not opposed by any party. The TPSC's order approving the Incentive Plan required Nashville and the TPSC's Staff to recommend a qualified independent consultant to review the progress of the Incentive Plan and to annually report the independent consultant's findings to the TPSC. The order also required Nashville to inform the TPSC by April 1, 1997, if it wished to continue the Incentive Plan for a second year.

On November 27, 1996, Nashville and the Authority's Staff submitted for the Authority's approval a contract for Andersen Consulting to perform annual reviews regarding the progress of the Incentive Plan. By Order dated January 2, 1997, the Authority determined that it was appropriate to accept the recommendation of the Company and the TRA's Staff that Andersen Consulting be employed as the independent consultant. The Authority approved the Andersen Consulting contract dated November 21, 1996.

By letter dated March 31, 1997, Nashville informed the Authority that it proposed to continue the plan for a second year, without modification. By letter dated April 7, 1997, Associated Valley Industries notified the Authority that it did not object to the Company's request. No party filed an objection to the Company's request. In accordance with its contract, Andersen Consulting filed its First Year Review of Performance Incentive Plan dated May 1, 1997, (hereafter the "First Report") and recommended that the Incentive Plan be continued for another year without modification. By Order dated June 30, 1997, the Authority authorized Nashville to continue the Incentive Plan for a second year, commencing July 1, 1997.

Andersen Consulting completed its Second Year Review of Performance Incentive Plan (hereafter the "Second Report") on March 23, 1998. By its Application dated March 31, 1998, Nashville requested that the Authority approve the Incentive Plan on a permanent basis, relying in large part upon the recommendations made by Andersen Consulting in its Second Report.

In the Second Report, Andersen Consulting found that:

> I. Based upon a review of Nashville's workpapers that were available following the publication of the First Report, the Incentive Plan's performance during the period July 1, 1996, through June 30, 1997, the first year of the Incentive Plan, was as follows:
>
> 1. Net savings totaled $1,379,000, the amount available to be split between the ratepayers and Nashville, subject to the 1% deadband.
>
> 2. Ratepayers "earned" $925,000 in savings during the first full year of the plan or about 67% of the amount available from the sharing mechanism and the amount within the 1% deadband.
>
> 3. Nashville "earned" $455,000 during the first full year of the plan or about 33% of the amount available from the sharing mechanism and the amount within the 1% deadband.
>
> 4. Nashville's share of gains/losses for the first full year of the plan was approximately 1/3 of the $1.6 million gains/losses cap.
>
> II. Based upon a review of Nashville's workpapers, the Incentive Plan's performance during the period July 1, 1997, through December 31, 1997, a period of six months into the second year of the Incentive Plan, was as follows:
>
> 1. Net savings for the first six months of the second year of the Incentive Plan totaled $769,000, the amount available

to be split between the ratepayers and Nashville, subject to the 1% deadband.

2. Ratepayers "earned" $598,000 in savings during the first six months of the second year of the Incentive Plan or about 78% of the amount available from the sharing mechanism and the amount within the 1% deadband.

3. Nashville "earned" $171,000 during the first six months of the second year of the Incentive Plan or about 22% of the amount available from the sharing mechanism and the amount within the 1% deadband.

4. Nashville's share of gains/losses for the first six months of the second year of the Incentive Plan was less than 11% of the $1.6 million gains/losses cap.

5. Nashville's net gains during the first six months of the second year of the Incentive Plan was largely attributable to the Incentive Plan's Gas Procurement Mechanism, a reversal from the first year of the Incentive Plan.

After summarizing the activity in the Gas Procurement Incentive Mechanism and Capacity Management Incentive Mechanism for the period July 1, 1997, through December 31, 1997, as well as evaluating Nashville's organizational policies and practices, Andersen Consulting made the following recommendations in the Second Report:[1]

1. Implement a permanent performance based ratemaking mechanism, based upon the merits of the Incentive Plan.[2]

2. Rollover the permanent plan automatically each year, unless Nashville gives advance notice of its need to either withdraw or change the Incentive Plan, or the Authority elects to modify, amend, or terminate the Incentive Plan.

[1] The Second Report also pointed out that "[t]he existence or absence of an incentive plan similar to [Nashville] is not, in itself, a confirmation or an indictment of [Nashville's] plan. Instead the case studies demonstrated the various plans used by other utilities operating in other jurisdictions and that [Nashville's] performance incentive plan was generally consistent with those industry practices." Second Year Review, dated March 23, 1998, at page 15.
[2] This recommendation was based, in part, upon the judgment of Andersen Consulting that the objectives of the two year period of the Incentive Plan were satisfied and the Incentive Plan resulted in benefits to both the ratepayers and Nashville. Id. at page 16.

3. Retain the employee incentive compensation plan that links reward with performance to ensure alignment of behavior and risk-taking with results.

4. Retain the primary features of the Incentive Plan, without modifications. A summary of those features include:

    A. Gas Procurement Mechanism:[3] 50/50 sharing arrangement, with a performance indicator of 99% of Index for Gains, and 101% of Index for Penalties.

    B. Capacity Management Mechanism:[4] Sliding scale from 100/0 to 50/50 as the sharing arrangement,[5] using the demand costs for transportation and storage capacity as the performance indicator.

5. Retain, without modifications, the "monthly price index" composite formula, as defined in the Appendix to the Second Report, that serves to compare Nashville's total city gate commodity cost of gas to a benchmark amount.

6. Having concluded the experimental period, remove the need for the permanent plan to be independently reviewed by a consultant, consistent with the Incentive Plan's objective of streamlining regulation and lowering regulatory costs.

At a regularly scheduled Authority Conference held on April 21, 1998, the Directors unanimously appointed the General Counsel or his designee to act as Hearing Officer to hear certain preliminary matters and to set a procedural schedule. A Pre-Hearing Conference was publicly noticed on June 4, 1998, and held on June 15, 1998, at 10:00 a.m. before Authority counsel, Dennis McNamee. Prior to the Pre-Hearing Conference, no party sought intervention in

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[3] The Gas Procurement Mechanism includes the primary elements of commodity costs, gas supply reservation fees, off-system sales and sale for resale transactions, use of financial instruments, both public and private contracts, hedges and swaps.

[4] The Capacity Management Mechanism includes the primary elements of release of transportation capacity, release of storage capacity, transportation of storage margin associated with off-system or wholesale sales-for-resale.

[5] As outlined in the Second Report, Nashville's share of the associated cost savings is calculated based on the actual capacity demand charges incurred by Nashville. Thus, the lower the demand charges and the greater the savings, the higher Nashville's sharing percentage. Id.

this proceeding. No interested parties, other than Nashville, appeared at the Pre-Hearing Conference. On June 15, 1998, the Hearing Officer filed his Report and Recommendation.

At a regularly scheduled Authority Conference held on June 30, 1998, the Directors considered the Hearing Officer's Report and Recommendation which recommended that the Application of Nashville Gas be brought before the Directors for consideration without a hearing since no parties had intervened nor had any objections to the Application been filed with the Authority. After reviewing the Report and Recommendation, and other relevant portions of the record, the Directors unanimously approved and adopted the Report and Recommendation of the Hearing Officer. This matter was scheduled for the Directors' consideration in July and, since the experimental period of the Incentive Plan expired on June 30, 1998, the Directors unanimously voted to allow the Company to continue operating under the incentive plan as it existed on June 30, 1998, until such time as the Authority further deliberated upon the matter and rendered a final decision on Nashville's Application.

On July 17, 1998, the Authority issued two Requests for Clarification to Nashville, the first of which outlined three (3) issues affecting Nashville's proposed Tariff Service Schedule No. 14. The Company responded to this first request by submitting, on July 23, 1998, a revised proposed tariff which incorporated the following new language:

1. Applicability Section: The Plan will continue until the Plan is either (a) terminated at the end of a plan year by not less than 90 days notice by Nashville to the Authority or (b) the Plan is modified, amended or terminated by the Authority.

2. Filing with the Authority Section: Unless the Authority provides written notification to the Company within 180 days of such reports, the Incentive Plan Account shall be deemed in compliance with the provisions of this Service Schedule.

3. Periodic Index Revisions Section: Unless the Authority provides written justification to the Company within 30 days of such notice, the price indices shall be deemed approved as proposed by the Company.

The second clarification request inquired as to the status of the Company's "feedback and reward system." The Company responded to this request by letter dated July 23, 1998, which further detailed Nashville's "feedback and reward system." Company representative, Bill R. Morris, executed an affidavit on July 31, 1998, attesting to his responses to each of these clarification requests. This affidavit, together with the clarification requests and responses thereto, was officially filed with the Authority and are part of the record considered in this matter.

This matter came before the Authority again at the regularly scheduled Authority Conference held on August 18, 1998. Having considered the First Report,[6] the Second Report,[7] the verified responses of Nashville to the Requests for Clarification, and other relevant portions of the record, the Authority unanimously approved Nashville's Application to extend its Incentive Plan, and directed Nashville to file a revision to its Service Schedule No. 14 Tariff, stating the following:

1. Nashville will continue to have in place the Gas Supply Incentive Compensation Program, as detailed to the Authority in its letter dated July 23, 1998; and,

2. Nashville will submit to the Authority, in writing, any proposed changes to the Gas Supply Incentive Compensation Program and, if the Authority elects to take no action concerning such proposed changes

[6] On July 31, 1998, Frank H. Creamer executed as affidavit, which is a part of the evidentiary record in this matter, stating that to the best of his knowledge his analysis, conclusions, and recommendations in his first and second year reports are true and accurate to the best of his knowledge and belief.

[7] Id.

prior to the end of sixty (60) days after the same shall have been filed with the Authority, then such proposed changes shall become effective.

The Authority unanimously agreed to allow the Incentive Plan, as revised, to be automatically renewed on July 1st of each year, beginning July 1, 1998, unless and until the Incentive Plan is either (a) terminated at the end of a plan year by not less than ninety (90) days notice by Nashville to the Authority or (b) the Incentive Plan is modified, amended or terminated by the Authority.

The Authority also found it appropriate to eliminate the requirement for an independent review of the Incentive Plan. Based upon the independent consultant's analysis, the benefits of the Incentive Plan have now been demonstrated. Furthermore, Nashville will continue to submit quarterly and annual reports of the operations of the Incentive Plan and, if such reports or any other information should raise questions about the continued operations of the Incentive Plan, the Authority may take such action as it deems appropriate.

It is the opinion of the Directors of the Authority that incentive plans such as that proposed by Nashville can satisfy the public interest by providing net benefits to both ratepayers and the Company.[8] Such net benefits can be realized when an incentive plan is carefully evaluated and properly administered, consistent with state law. In Nashville's case, the Authority concludes that the Incentive Plan satisfies the public interest. The Authority further concludes that it is consistent with the goal of keeping expenses at a minimum to establish a Gas Supply Incentive Compensation Program to recognize selected Gas Supply non-executive employees

[8] In formulating its decision in this matter, the Authority is mindful of the dicta offered by the Court of Appeals in its March 5, 1997, decision in Tennessee Consumer Advocate v. Tennessee Regulatory Authority, 1997 WL 92079, *4 (Tenn. Ct. App.), wherein the Court noted: "Of particular interest and concern are the propriety of . . 'rewarding' [a] utility for keeping its expenses at the minimum, and of utilizing the services of an expert employed by the utility."

who are directly involved in managing such expenses. The public interest is served by performance measures for the Incentive Plan being established on an annual basis and by employees receiving incentive compensation as recognition for their contribution to the ratepayers and Nashville's shareholders through lower gas costs and gains related thereto.

IT IS THEREFORE ORDERED THAT:

1. Consideration of Nashville Gas Company's application for the extension of the Incentive Plan on a permanent basis does not require a hearing because no parties have intervened and no objections to Nashville's Application have been filed with the Authority;

2. Nashville Gas Company is authorized to continue to operate under the Incentive Plan, as modified herein, in such a manner that the Incentive Plan will automatically rollover for an additional plan year on each July 1st, beginning July 1, 1998, and will continue until the Incentive Plan is either (a) terminated at the end of a Plan Year by not less than 90 days notice by Nashville to the Authority or (b) the Incentive Plan is modified, amended or terminated by the Authority;

3. The requirement for an independent review of the Incentive Plan is eliminated;

4. The Company shall amend Service Schedule No. 14 of its Tariff by inserting a section entitled "Gas Supply Incentive Compensation Program" which provides that while the plan is in effect the Company will continue to have in place its "Gas Supply Incentive Compensation Program" as detailed in the Company's July 23, 1998, response to the Authority's second clarification request of July 17, 1998. This section of the tariff shall further provide that

the Company is required to notify the Authority in writing of any changes to the Gas Supply Incentive Compensation Program and, unless the Company is otherwise notified by the Authority within sixty (60) days, said changes will become effective.

5. Any party aggrieved with the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within ten (10) days from the date of this Order; and

6. Any party aggrieved with the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty (60) days from the date of this Order.

Melvin J. Malone, Chairman

H. Lynn Greer, Jr., Director

Sara Kyle, Director

ATTEST:

K. David Waddell, Executive Secretary

NASHVILLE GAS COMPANY
REVIEW OF NASHVILLE GAS COMPANY'S IPA
RELATING TO ASSET MANAGEMENT FEES
DOCKET NO. 05-00165
CONSUMER ADVOCATE AND PROTECTION DIVISION
SECOND SET OF DISCOVERY REQUESTS
January 3, 2006

DISCOVERY REOUEST NO. 24

In response to Discovery Request No. 1, of the Consumer Advocate's First Set of Discovery Requests; Nashville Gas Company objected to the scope of the discovery request and stated that it has not yet determined whether to call any "independent expert witnesses." The Consumer Advocate propounds the following question:

Please identify each person whom you expect to call as an expert witness at any hearing in this docket -- regardless of whether such expert witness is hired as an "independent expert witness" or whether such expert witness is employed by Nashville Gas Company, Piedmont Natural Gas Company, or any other company -- and for each such expert witness:

(a) State the subject matter on which the expert witness is expected to testify;

(b) State the substance of the facts and opinions to which the expert witness is expected to testify;

(c) Provide the grounds (including any factual bases) for each opinion to which the expert witness is expected to testify;

(d) Provide complete background information, including the expert's current employer as well as his or her educational, professional and employment history, and qualifications within the field in which the witness is expected to testify, and identify all publications written or presentations presented in whole or in part by the witness;

(e) Identify any matter in which the expert has testified (through deposition or otherwise) by specifying the name, docket number and forum of each case, the dates of the prior testimony and the subject of the prior testimony, and identify the transcripts of any such testimony;

(f) Identify the terms of the retention or engagement of each expert including but not limited to the terms of any retention or engagement letters or agreements relating to his/her engagement, testimony, and opinions as well as the compensation to be paid for the testimony and opinions; and

(g) Identify any exhibits to be used as a summary of or support for the testimony or opinions provided by the expert.

(h) Produce a copy of all documents (defined above) relied upon by the expert witness for the facts and opinions to which the expert witness is expected to testify.

If Nashville Gas objects to a particular subsection(s) of this interrogatory but not to other subsections, please provide a complete answer for each subsection for which there is no objection. If Nashville Gas objects to any subsection(s) of this interrogatory pursuant to the Tennessee Rules of Civil Procedure or any other rule of law, please state in detail the factual and legal bases for each such objection.

SUPPLEMENTAL RESPONSE: Please see the attached curriculum vitae of Daniel M. Ives and Jay P. Lukens.

JAY P. LUKENS

Sr. Vice President
Black & Veatch Corporation

President
Lukens Energy Group

Business Strategy,
Mergers & Acquisitions,
Regulatory Policy,
Energy Market Analysis,
Business Development,
Energy Project
Commercial
Management

Education
Ph D , Economics, 1981
Texas A&M University,
College Station, TX

B A , Economics, 1977
Eckerd College,
St Petersburg, FL

Total Years Experience
24

Joined LEG
1999

Professional Associations
Board of Trustees, Eckerd College
Member, Energy Bar Association, 2001 - 2005
E-Commerce Committee Chair, Energy Bar Association, 2002 - 2003
International Association for Energy Economics, 1996 - 2005
Board of Directors, INGAA Foundation, 1989 - 1995, 1997 - 2002
Member, Rate Committee, INGAA, 1986 - 1995
Member, Policy Analysis Committee, INGAA, 1986 - 1995

Language Capabilities
English

Jay P Lukens 1/2/2006

As President and founder of Lukens Energy Group (LEG), now a part of the Enterprise Management Solutions Division of Black & Veatch Corporation, Dr. Lukens brings to clients over twenty years of diverse, senior-level corporate and consulting experience within the energy and telecommunications industries. Dr. Lukens has worked with the senior management of major energy companies in evaluating mergers, acquisitions, and market entry strategies. He advises clients on issues of business strategy, energy policy, regulation, business development, and energy project development. Dr Lukens has provided testimony as an expert witness to state and federal courts and regulators on a wide variety of issues related to energy markets, including antitrust, analysis of market competition, and economic damages.

From 1985 to 1995 Dr. Lukens was a senior executive with Transco Energy Company where he had direct responsibility for strategic planning, federal regulatory affairs, and business development Dr Lukens had oversight responsibility for Transco's efforts to resolve civil and FERC litigation in connection with the restructuring of the natural gas industry in the early 1990's.

Representative Project Experience

State of Alaska – Alaska Gas Pipeline Project
Provide strategy and regulatory counsel to the Natural Gas Cabinet for the State of Alaska in its negotiations with North Slope producers and independent pipeline developers relating to the $20 billion Alaska Gas Pipeline. Dr. Lukens' roles for the State have been varied, ranging from directing background analysis on key issues to spokesperson at negotiating sessions.

ExxonMobil Golden Pass Pipeline
Utilized MarketBuilder™ software to forecast the market price and basis trend at major pricing points located in the Texas and Louisiana region for the period of 2005 to 2040 by explicitly incorporating developments in demand, production, pipeline infrastructure and LNG terminals in the region and around the country. Major drivers of the market dynamics are identified and their economic impact to the LNG terminal quantified. A specific marketing strategy to pursue the high premium markets is proposed. Applying the cutting-edge real option theory and utilizing the proprietary Transportation Valuation Advisor™ and Storage Valuation Advisor™ software, Lukens Energy Group also identified significant intrinsic and extrinsic value embedded in the multiple delivery point pipeline header system and tank storage space and recommended active asset management strategies to obtain the value

Confidential Client – Interstate Pipeline Growth Strategy

In 2004 Dr. Lukens was retained by a confidential client to help senior management develop a growth strategy for its interstate pipeline business. LEG performed a market study to develop a long-term view of the natural gas market relative to client's pipeline and storage assets. LEG modeled the transmission systems of potential competitors and developed cost estimates for competitive service offerings. Study included a review of rate and regulatory issues and consideration of new rate designs to improve clients' competitive position vs. new LNG suppliers entering their market. Based on the market study and knowledge of client's and competitor's assets, LEG identified specific storage and transmission projects to grow EBIT by more than $100 million per year. LEG presented its findings and recommendations to the client's Board of Directors.

NiSource

Dr. Lukens directed an engagement for NiSource to support their successful effort to acquire Columbia Energy. LEG developed cash flow models of Columbia's pipeline, energy marketing and gas LDC business units, advised NiSource on the potential economic effect of pending regulatory issues; evaluated potential expansion strategies for the Columbia business units, and participated in risk analysis and scenario planning. Following the merger, LEG was retained to assist with merger integration. Focus of the effort was integration of energy marketing operations at the two companies. LEG led a task force comprised of NiSource and Columbia executives to identify specific strategies and action steps to achieve earnings growth targets.

Confidential Client – Storage Asset Acquisition

LEG was engaged to perform an independent assessment of the Mid-Atlantic market and to assess the value of the revenue potential from the Stagecoach storage facility. LEG performed a detailed review of Mid-Atlantic natural gas capacity, demand and prices as well as factors affecting these dynamics using an economic market model to analyze the market fundamentals. The insights from the economic model such as regional consumption forecasts, pipeline utilization and monthly basis differentials were utilized to assess the potential role of Stagecoach storage facility given market expectations in the Mid-Atlantic region. LEG also performed a valuation of storage services from Stagecoach facility using LEG's proprietary Storage Valuation AdvisorTM (SVA) software. Valuation included intrinsic and extrinsic value of the storage services at Stagecoach based on a real option valuation methodology. As part of the acquisition support, LEG also reviewed pro-forma revenue projections for the Stagecoach facility provided by the seller, eCORP.

Reliant - California – Response to Report of FERC Staff
Dr. Lukens assisted Reliant Energy in responding to the Report of FERC Staff (the "March 26 Report") in Docket No. PA02-2-000 (March 2003) which analyzed, among other subjects, the impact of so-called "churning" by one Reliant physical gas trader. The Report alleged that this trading behavior likely caused some intraday and interday increases in the gas price indices for Topock. According to the March 26 Report, the higher market gas prices associated with the alleged "churning" increased the market cost of gas by $650 million in December 2000 and by about $1.15 billion for the 8-month refund period November 2000 through June 2001 (the "Refund Period"). Based in part on Lukens Energy Group's work, Reliant was able to settle this matter without paying any damages.

Testimony

AES Express LLC
Testimony on behalf of the LNG Suppliers Coalition, which consisted of BP Energy Company, Chevron U.S.A Inc., ConocoPhillips Company, ExxonMobil Gas & Power Marketing Company, a division of ExxonMobil Corporation, and Shell NA LNG, LLC. Provided opinions regarding the regulatory policy issues raised by gas interchangeability standards and specifications proposed by Florida Gas Transmission and recommendations for how the FERC should address them. Docket No. RP04-249-001. Written report filed September 19, 2005. Cross-answering testimony filed November 7, 2005.

Williams Companies, Inc
Testimony on behalf of Williams Companies, Inc. successor in interest to one of the partners in Great Plains Gasification Associates for the Great Plains Project. Providing opinion to Federal Tax Court as to whether such bid was a legitimate business proposal from the perspectives of the equity partners and the federal government. Docket No 206. Written report filed December 23, 2004.

NSTAR Gas and Electric Corporation
United States of America before the Federal Energy Regulatory Commission, Devon Power et al, LLC.
Answering testimony providing opinion as to whether the ISO New England's proposed Locational Installed Capacity pricing proposal is a market mechanism that yields market-based prices. Testimony also addresses standard by which ISO New England's Location Installed Capacity monthly capacity pricing should be scrutinized. Docket No. ERO3-563-030. Written testimony filed November 4, 2004. Cross-answering testimony filed February 17, 2005.

SCANA Corporation
Testimony on behalf of SCPC in response to a Public Service Commission of South Carolina. Expert Testimony in response to an order directing SCPC to present testimony and information in a proceeding concerning put options and other financial devices that maybe employed by SCPC in its purchase of gas supplies to meet the future demand of its customers. Docket No. 2003-236-G. Written report filed October 30, 2003.

Grynberg
Shell Oil Company, Shell Western E&P Inc., Shell Cortez Pipeline Company, Kinder Morgan CO2 Company, L P., formerly known as Shell CO2 Company, Ltd. ("Shell"), Exxon Mobil Oil Corporation, formerly known as Mobil Oil Corporation, Mobil Producing Texas and New Mexico, Inc., ("Mobil"), and Cortez Pipeline Company. Expert Testimony that analyzed the Plaintiffs' claims concerning the tariffs charged by Cortez Pipeline Company to move CO2 from the McElmo Dome Unit in southwestern Colorado to Denver City, Texas in the Permian Basin. Docket No. 1998 CV-43. Written report filed June 20, 2003. Supplemental Report filed August 15, 2003.

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.
San Diego Gas and Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Power Exchange. Affidavit responding to FERC Staff's Final Report on Price Manipulation in Western Markets. Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Docket No. PA02-2-000. Written report filed April 25, 2003.

Northern Indiana Public Service Company
Rebuttal Testimony before the Indiana Utility Regulatory Commission. Expert Testimony in NIPSCO's 2003 Gas Cost Adjustment Case that addresses issues raised in the Indiana Office of Utility Consumer's Counselor's (OUCC) regarding the run up of gas prices in March 2003. Written report filed April 9, 2003.

Piedmont Natural Gas Company
Report on Analysis of Market Power Related to the Proposed Purchase of North Carolina Natural Gas. Expert Testimony examining whether the acquisition of North Carolina Natural Gas will lead to an increase in market power that could be detrimental to the welfare of consumers. Written report filed December 6, 2002.

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.
Report on California Border Prices - Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Expert Testimony analyzing the Initial Report of FERC Staff in Docket No. PA02-2-000 (August 2000) Written report filed October, 2002.

Nova Scotia Power Inc. (NS Power)
Report on Agency and Surplus Thermal Generated Energy Purchase and Sale Agreement between Emera Energy Inc. and Nova Scotia. Expert Testimony analyzing the economic and regulatory policy implications of the Agency and Surplus Thermal Generated Energy Purchase and Sale Agreement between Nova Scotia Power Inc. and Emera Energy Inc. Written report filed October 4, 2002.

EnerGas (The City of Lubbock)
The City of Lubbock, Texas and the West Texas Municipal Power Agency vs. Stewart & Stevenson Energy Products, Inc., aka S&S Energy Products, Inc., a Division of GE Packaged Power, Inc., and EnerGas, a Division of ATMOS Energy; Cause No. 2001-513, 945, in the 99th Judicial District Court of Lubbock County, Texas. Expert Testimony evaluating the assumptions made in Plaintiffs' damage calculation and analyzing the economic logic employed in calculating purported economic damages Written report filed August 22, 2002.

ProGas Limited (ProGas)
In the Matter of a Gas Purchase Contract by and between ProGas Limited as Seller, and Ocean State Power, as Buyer Dated December 14, 1998, as Amended Effective December 1, 1999. Prepared direct testimony in a private arbitration dispute regarding analysis of the arbitration standard in a gas sales contract. Written evidence filed August 17, 2002. Response Testimony filed October 17, 2002.

Transcontinental Gas Pipeline Corporation (Transco)
United States of America before the Federal Energy Regulatory Commission, Docket No. RP01-245-000, et al Prepared Rebuttal Testimony addressing the economic substance of, and the regulatory issues concerning a transaction between Transco and Williams Communications Company ("WCC"), wherein Transco agreed not to oppose WCC's use of the Transco right-of-way. Written Report filed May 31, 2002.

Amoco Production Company
Richard Parry, et al., vs. Amoco Production Company; Case No. 94 CV 105; District Court, County of La Plata, State of Colorado. Expert testimony analyzing the economic implications of the Plaintiffs' and Experts' claims regarding post-production fees charged by Amoco for Coal Seam Gas in the San Juan Basin. Written Report filed May 1, 2002.

Amoco/Shell/Amerada Hess
Ray Powell, Commissioner of Public Lands of the State of New Mexico, Trustee, vs. Amoco Production Company, Amerada Hess Corporation, Shell Western E&P, Inc., and Shell Land & Energy Co.; Case No. D-0101-CV-2000 02079; First Judicial District, State of New Mexico, County of Santa Fe. Expert testimony analyzing the economic implications of the Plaintiff's and its Experts' claims concerning the tariffs charged for transportation of CO_2 on the pipelines connecting the Bravo Dome to EOR projects in the Permian Basin. Written Report filed September 21, 2001. Supplemental Expert Report filed January 11, 2002.

Exxon Mobil Corporation
DETMI Management, Inc., Duke Energy Services Canada Ltd, and DTMSI Management, Ltd. vs. Mobil Natural Gas, Inc. and Mobil Canada Products, Ltd., Cause No. 50 T 198 00485 00; American Arbitration Association. Expert testimony analyzing the natural gas and power trading and marketing business in connection with a dispute regarding the operation of Duke Energy Trading and

Marketing, a joint venture of Duke Energy and Exxon Mobil. Written Expert Report filed July 31, 2001

Shell Oil Company, Shell Western E&P, Inc. and Mobil Producing Texas and New Mexico, Inc
CO2 Claims Coalition, et al., vs Shell Oil Company, et al., in the United States District Court for the District of Colorado, CIV. No. 96-Z-2451. Expert Report analyzing the economic implications of the Plaintiffs' and their Experts' claims concerning price fixing and anti-competitive behavior in establishing the tariffs charged by Cortez Pipeline Company to move CO2 from the McElmo Dome Unit in southwestern Colorado to Denver City in the Permian Basin. Second Supplemental Expert Report filed March 30, 2001.

Philadelphia Gas Works
Before the Pennsylvania Public Utility Commission, Philadelphia Gas Works Docket No. R-00006042 Prepared Direct Testimony in Philadelphia Gas Works' Base Rate Proceeding addressing the cost of service of the company if it were an investor owned utility. January 16, 2001.

Carthage Energy Services, Inc and Dominion Energy
United States of America before the Bankruptcy Court for the Southern District of Texas, Houston Division, Case No. 99-32383-H2-11, Case No. 99-32384-H4-11, Jointly Administered under Case No 99-32383-H2-11, Adversary No. 00-3290. Expert Report related to certain damage calculations under the Proof of Claim filed by Carthage Energy Services on May 4, 2000 Also reviewed the reports submitted by the Trustee's Experts and responded to certain statements contained in such reports, January 6, 2001.

El Paso Natural Gas Company
United States of America before the Federal Energy Regulatory Commission, Public Utilities Commission of the State of California v. El Paso Natural Gas Company, et al., Docket No. RP00-241-000 Expert Report analyzing the performance of the California gas market, filed in rebuttal to claims by the CPUC that El Paso had exercised market power over natural gas transportation services serving California, September 29, 2000. Report updated December 13, 2000.

Texas Gas Transmission Corporation
United States of America before the Federal Energy Regulatory Commission, Texas Gas Transmission Corporation, Docket No. RP00-260-000. Testimony supporting proposal for seasonal and term differentiated rates for short-term transportation services. Also addressed analysis of the supply and demand balance and the business risk in the market for pipeline capacity in which Texas Gas participates, April 21, 2000.

ATCO Gas Company
Before the Alberta Energy and Utilities Board, Nova Gas Transmission Ltd, on behalf of ATCO Gas Company. Testimony for alternative rate design for Nova Gas Transmission Ltd. Written evidence submitted on August 10, 1999.

El Paso Natural Gas Company
United States of America before the Federal Energy Regulatory Commission, El Paso Natural Gas Company, Docket No. RP97-287-010. Expert Report filed to rebut claims by CPUC regarding effect on California gas market of contract between Dynegy Corp and El Paso Natural Gas, May 6, 1999.

El Paso Natural Gas Company
United States of America before the Federal Energy Regulatory Commission, Docket No. RM98-10, Regulation of Short-Term Natural Gas Transportation Services, Docket No. RM98-12, Regulation of Interstate Natural Gas Transportation Services. Expert Report (with Adam Jaffe) regarding economic impact of FERC's proposed rule, April 12th, 1999.

Transcontinental Gas Pipeline Company
United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipeline Company, Docket No. CP98-74-001. Prepared Answering Testimony on behalf of Transco analyzing competitive effects of refusal to construct interconnect, January 5, 1999.

Northern Natural Gas Company and Dynegy Energy Resources, Limited Partnership,
Bearpaw Gathering Systems, Inc., et al., vs. Northern Natural Gas Company and Dynegy Energy Resources, Limited Partnership, f/k/a NGC Energy Resources, Limited Partnership, vs. Ocean Energy, Inc., in the United States District Court for the Southern District of Texas, Cause No 97-47540 Expert testimony in natural gas contract dispute, December 22, 1998.

Shell Oil Company, Shell Western E&P, Inc., and Mobil Producing Texas and New Mexico, Inc.
CO2 Claims Coalition, et al., vs. Shell Oil Company, et al., in the United States District Court for the District of Colorado, CIV. No. 96-Z-2451. Expert Report analyzing the economic implications of the Plaintiffs' and their Experts' claims concerning price fixing and anti-competitive behavior in establishing the tariffs charged by Cortez Pipeline Company to move CO2 from the McElmo Dome Unit in southwestern Colorado to Denver City in the Permian Basin, November 2, 1998. Supplemental Expert Report filed April 30, 1999.

El Paso Natural Gas Company
United States of America before the Federal Energy Regulatory Commission, El Paso Natural Gas Company, Docket No. RP97-287-010. Expert Report (with Adam Jaffe) filed with the Initial Comments of El Paso in the technical conference in this docket analyzing the policy issues raised by the contracts between El Paso and Natural Gas Clearinghouse, February 26, 1998. Expert Report filed with the Reply Comments of El Paso in the technical conference in this docket analyzing the competitive impacts of the contracts between El Paso and Natural Gas Clearinghouse, April 14, 1998.

Texas New Mexico Power Company
State of Texas, State Office of Administrative Hearings, Application for Approval of the TNMP Transition Plan and Statement of Intent to Decrease Rates, and Municipal Rate Appeals, SOAH Docket No. 473-97-1561 Prepared Rebuttal Testimony in Support of Restated Stipulation. Policy testimony on terms of competition and conditions of entry in electric restructuring case, March 2, 1998.

AEC Oil & Gas, a Division of Alberta Energy Company, Ltd., Canadian Forest Oil Ltd., and ProGas Limited
In Arbitration, Alberta Northeast Gas Limited vs. AEC Oil & Gas, a Division of Alberta Energy Company, Ltd., Canadian Forest Oil Ltd., and ProGas Limited. Testimony regarding proper interpretation of long-term gas sales contract. Prepared Direct Testimony, January 26, 1998 Reply Testimony, February 11, 1998.

CNG Transmission Corporation
United States of America before the Federal Energy Regulatory Commission, CNG Transmission Corporation, Docket No. RP97-406-000. Prepared Direct Testimony. Expert testimony on market power in secondary market for pipeline capacity, July 1, 1997.

Leidy Line Roll-in Group
United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line, Docket No. RP95-197 & RP 97-71 (Consolidated). Prepared Answering Testimony, March 25, 1997 Cross-Answering Testimony filed May 12, 1997

Amoco Production Company
In the Matter of Doris Feerer, et al. vs. Amoco Production Company, et al., Civ. No. 95-0012-JC/WWD in United States District Court for the District of New Mexico. Expert report regarding vertical integration and transfer pricing in a royalty dispute, May 5, 1997.

Oklahoma Gas and Electric Co.
Prepared Rebuttal Testimony before the Corporation Commission of the State of Oklahoma, Cause No PUD 960000116, on behalf of Oklahoma Gas and Electric Company. Recommended the proper allocation of costs for the Enogex pipeline system between Oklahoma Gas and Electric and third party transportation services, November 6, 1996.

Nashville Gas Company
Prepared Direct Testimony before the Tennessee Public Service Commission, Docket No. 96-00805, on behalf of Nashville Gas Company, A Division of Piedmont Natural Gas Company. Proposed a performance incentive program for Nashville's gas procurement and capacity costs, April 22, 1996.

Jay P Lukens
1/12/2006

Leidy Line Roll-in Group
United States of America before the Federal Energy Regulatory Commission, Docket No. RP95-197-000 (Phase II) Expert testimony supporting rolled-in rate treatment for Transco's existing incrementally priced expansion projects. Other Answering and Rebuttal Testimony filed as case progressed, January 24, 1996.

Transcontinental Gas Pipe Line Corporation (Transco)
United States of America before the Federal Energy Regulatory Commission, Docket No. RP95-197-000, Prepared Direct Testimony on behalf of Transco. General policy issues in rate case, March 15, 1995.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP93-100, Prepared Direct Testimony on behalf of Transco, supporting the terms and conditions of Transco's contract settlement with Dakota Gasification. Other Supplemental, Answering, and Rebuttal Testimony filed as case progressed, December 19, 1994

United States of America before the Federal Energy Regulatory Commission, Docket No. RM94-4, Public Conference on Natural Gas Gathering Issues, testimony and response to questions before the Commission members and their staff, February 24, 1994

United States of America before the Federal Energy Regulatory Commission, Docket No. RP92-137, Prepared Direct Testimony on Behalf of Transco, addressing general policy issues in rate case; primary issue in litigated phase of the case was the design of rates for production area services. Supplemental, Answering, and Rebuttal testimony filed as case progressed, March 17, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP92-108, Prepared Direct Testimony on Behalf of Transco, supporting general policy issues in rate case, March 10, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. CP92-378, Prepared Direct Testimony on Behalf of Transco, addressing the design of an incentive rate mechanism for gas pipelines, February 28, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RM90-1, Public Conference on Pipeline Construction Rulemaking, testimony and response to questions before the Commission members and their staff, January 28, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP90-8, Prepared Direct Testimony on Behalf of Transco, supporting proposal for new transportation rate design consistent with unbundled service structure, October 24, 1989.

United States of America before the Federal Energy Regulatory Commission, Docket No RP87-7, Prepared Direct Testimony on Behalf of Transco, addressing the reserved issues of rate design and the terms and conditions of transportation service, supported proposal for a price deregulated secondary market in pipeline capacity rights, June 21, 1989

United States of America before the Federal Energy Regulatory Commission, Docket No. TA85-3-29, Prepared Answering Testimony on Behalf of Transco in remedies phase of FERC enforcement action, February 13, 1989.

Publications and Research

"Energy: Turning The Corner and Finding New Ground for Growth" Power & Gas Marketing Fall 2003

"Getting Real. How to Optimize the Value of Storage Assets" with Deepa Poduval, Natural Gas, October 2002

"Increasing Price Volatility Sparks Interest in Energy Finance Arena", Houston Business Journal, June 1-7, 2001

"Pricing and Integrated Energy Transmission Grid Are FERC's Natural Gas and Electric Power Transmission Pricing Policies on a collision course?" The Electricity Journal, March 2000

"The Pipeline's View: FERC's Proposed Rule Misses the Mark," with Adam Jaffe, Public Utilities Fortnightly, July 1, 1999.

"Benefits of Retail Electricity Competition in Low Cost States," with Greg Hopper and Frank Felder, Electricity Journal, August/September 1998

"Should a Marketer Manage Your Supply Assets?" with Greg Hopper, Hart's Energy Markets, February 1998

"Whither the Contract for Pipeline Capacity," Natural Gas Focus, January 1996.

"Comparison of Transportation Information Systems in the Gas and Electric Industries," EME Working Paper, December 1995.

Representative Presentations

Oil & Gas Agreements: The Production and Marketing Phase, Rocky Mountain Mineral Law Foundation, May 19 – May 20, 2005 – Santa Fe, New Mexico

Broadwater Energy's Proposed Offshore Liquefied Natural Gas Importation Terminal," Remarks to New York State Legislature, February 15, 2005 - Albany, NY

"2005 Pipeline Opportunities Conference", Pipeline & Gas Journal, January 25, 2005 – Houston, TX

"Beyond the Basis", Tennessee Gas Pipeline - 2004 Shipper Meeting, May 26-28, 2004 – Hollywood, FL

"Effects of LNG Development on Domestic U S Pipeline Grid," Energy Bar Association - Market and Regulatory Implications of LNG Development, April 28, 2004 – Washington, DC

Executive Round Table - Southern Gas Association Management Conference, April 19, 2004 – Hilton Head Island, SC

"Interpreting Natural Gas Supply Indicators, Defining Index Price Integrity and Understanding Regulatory Developments," American Gas Association, July 17, 2003 - Washington, DC

"Emerging Strategic Issues for LDCs," presentation to Southern Gas Association Board of Directors, April 2003

"Gas – Power Convergence," presentation to PSEG's Senior Management Group, April 2003

"Natural Gas Supply - Demand and Pricing", Corporate TeleLink Network CTN) - The Energy Network & the Energy Bar Association, September 23, 2003 - Washington, DC

"An Approach to Analyzing the Effects of LNG Imports on Natural Gas Price Volatility", INFOCAST. Gas Volatility - Quantifying, Modeling and Managing Gas Price Volatility, September 24, 2003 - Houston, TX

"Overview of National Petroleum Council's Natural Gas study," Lukens Energy Group Breakfast Forum, October 16, 2003 - Houston, TX

"LNG Tutorial" - International LNG Alliance and United States Energy Association, December 10, 2003 - Washington, DC

"Valuation of Energy Companies" two-day seminar conducted in London for Euromoney Training

"Valuation of Gas Storage and Transportation Assets," INFOCAST Seminar, October 2002

Honors and Awards

Recipient of the Alfred Chalk Award to the Outstanding Graduate Student, Department of Economics, Texas A&M University, 1981

Thomas Presidential Scholar, Eckerd College, 1973 – 1977

DANIEL M. IVES

Vice President

Expert Witness, Regulatory Strategy, Litigation, Financial Analysis, Cost of Service, Cost Allocation, Rate & Tariff Design, M & A Due Diligence

Education
Certified Public Accountant
State of Maryland -1979
B. S., Business and Commerce
University of Maryland -1975
B A , Liberal Arts
University of Maryland - 1970

Total Years Experience
27

Joined LEG
1999

Professional Associations
American Gas Association - Rate & Strategic Planning Committee
Associate Member, 2002-Present
Chair, 1997
Vice Chair. 1995-1996
Member, 1987-1995
American Gas Association
Associate Member
1999-Present
American Public Gas Assoc.
Associate Member 2000-Present
American Institute of Certified Public Accountants
Member
Houston Energy Association
Member 1999-2003
Energy Bar Association
Associate Member 2002-Present
Texas Society of Certified Public Accountants – Houston Chapter
Member 2003-Present

Language Capabilities
English

Dan Ives is a Vice President with Lukens Energy Group (LEG), a part of the Enterprise Management Solutions Division of Black & Veatch Corporation. He has over twenty-five years of energy industry experience in leadership positions at three major natural gas pipeline and distribution companies. primarily in the area of rates and regulatory affairs. Mr. Ives' consulting focus is on assisting clients in maximizing business opportunities through rates and regulatory strategy, project development, and the financial management process. He also provides regulatory training services and litigation and regulatory support, including expert testimony on such matters as natural gas costs, cost of service, cost allocation, and rate and tariff design.

Representative Project Experience

Alaska Natural Gas Pipeline
Mr. Ives assisted outside counsel for the State of Alaska's Department of Law develop and evaluate regulatory positions and responses to proposed Federal regulation related to the Alaska Natural Gas Pipeline Project. Mr. Ives made a presentation to the Alaskan joint legislative committee describing the Federal regulatory process and pipeline open season practices.

Gas Distribution Risk Consequence Analysis
Mr. Ives developed a forward-looking risk consequence-based analytical approach to pipeline replacement for a major natural gas distribution company. The project analyzed industry and utility leak data to determine the consequences of pipeline and service line leaks on a population density-adjusted basis. Mr. Ives also prepared expert testimony for the utility.

Pipeline Certificate Application
Mr. Ives assisted an intrastate pipeline company prepare an application for a Certificate of Public Convenience and Necessity to convert the pipeline to an interstate pipeline subject to Federal Energy Regulatory Commission ("FERC") regulation. The project included preparation of cost of service adjustments, cost allocation studies, and rate design, including a distance-sensitivity study to support zone rates. Mr. Ives also prepared various supporting schedules for the application and assisted Client with presentations before Federal regulatory personnel in advance of filing the application.

Pipeline Cost Service Study
Mr. Ives prepared a cost of service study for an intrastate pipeline in support of transportation and storage services rendered to an electric utility affiliate. Dan presented expert testimony before the state Commerce Commission in support of the study.

Revenue Stabilization Adjustment Mechanism ("RSAM")
Mr. Ives developed an RSAM for a major Southeast natural gas distribution utility to recoup revenues otherwise lost to the adverse affects of weather, declining use per customer, and customer attrition. Mr. Ives also prepared tariff language and computational schedules in support of the mechanism, along with a regulatory presentation.

Daniel M Ives
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Gas Strategy Development
The Cove Point and Elba Island LNG terminals have dramatically changed the natural gas market in the Southeastern U.S. Mr Ives and the project team analyzed the implications to natural gas basis and pipeline flows in the Southeast from these LNG terminals and their associated expansions Using the firm's proprietary models, the project forecasted how basis may change in the region under different pipeline expansion scenarios. Based on the results of this analysis, the team assisted the Client develop upstream pipeline capacity strategies and expansion strategies for its intrastate pipeline affiliate.

Expert Testimony

Algonquin Gas Transmission Company
United States of America before the Federal Energy Regulatory Commission, Algonquin Gas Transmission Company, Docket No. RP 93-14-000. Prepared Direct Testimony on behalf of Algonquin filed on November 6, 1992. Policy testimony on rate design and the proposed rate increase and introduction of Algonquin's other witnesses. Supplemental Direct Testimony filed on behalf of Algonquin reviewing Commission policy on the showings necessary in order to roll-in incremental rates. Rebuttal Testimony was filed in response to various depreciation, cost classification, cost allocation, rate design and tariff matters, including the design of backhaul rates - a limited issue that was set for hearing. Additional Rebuttal Testimony filed on rolled-in rate issues.

Empire State Pipeline Company
State of New York before the Public Service Commission, Empire State Pipeline Case 95-G-1002. Prepared direct testimony on behalf of Empire State Pipeline Company supporting the general policy issues of the rate filing and introducing company witnesses, adopted July 16, 1996 at an evidentiary hearing. The case settled and the Commission issued an order of approval effective September 24, 1996.

Energas Company
Before the Railroad Commission of Texas, Petition of Energas Company for Review of the Rate Action of Lamesa, Texas (and other cities), GUD Docket No. 9002-9135. Prepared direct testimony filed on March 7, 2000 on behalf of Energas Company, a unit of ATMOS Energy Corporation. Also filed rebuttal and supplemental rebuttal testimony and stood cross-examination. The testimony sponsored a class cost of service and a proposed revised declining block rate design, as well as a proposed system expansion rider, a steel pipe replacement rider, and revisions to miscellaneous service charges. The parties settled the case.

Daniel M Ives
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Enogex Inc.
Before the Corporation Commission of the State of Oklahoma, Application of Oklahoma Gas and Electric Company, Cause No. PUD 200300226. Prepared direct testimony filed April 9, 2004 on behalf of Enogex Inc., a wholly-owned subsidiary of Oklahoma Gas and Electric Company ("OG&E"). The testimony describes and explains a cost of service study that was prepared for the natural gas transportation and storage services that Enogex provides to OG&E. Stood cross-examination in September 2004.

Hope Gas, Inc. (DBA "Dominion Hope")
Before the Public Service Commission of West Virginia, Case No. 01-0330-G-42T and Case No. 01-0331-G-30C. Prepared rebuttal testimony filed September 19, 2001 on behalf of Dominion Hope. The testimony describes and supports Hope's proposed adjustment related to the regulatory treatment of its negative pension expense and related issues. The parties settled the case.

Frederick Gas Company, Inc.
Before the Public Service Commission of Maryland, Case No. 8213. Prepared Direct Testimony filed on October 6, 1989 on behalf of Frederick Gas Company, Inc. in its general rate case. The testimony describes a stipulation and Agreement reached by the parties to the proceeding and provides supporting information for the settlement rates.

Before the Public Service Commission of Maryland, Case No. 8510. Prepared Direct Testimony filed December 3, 1985 on behalf of Frederick Gas Company, Inc. The testimony describes cost savings to firm customers as a result of Frederick's spot market gas purchases and the continued benefit of Frederick's special contract interruptible sales program.

Philadelphia Gas Works
Before the Pennsylvania Public Utility Commission, Case No. R-00017034. Prepared Direct Testimony filed February 25, 2002 on behalf of Philadelphia Gas Works (PGW). The testimony describes and supports PGW's proposed Cash Flow ratemaking methodology and PGW's Cash Working Capital requirements.

SCANA Energy Marketing, Inc.
Before the Georgia Public Service Commission, Docket No. 16682-U. Prepared Direct Testimony filed April 25, 2003 on behalf of SCANA Energy Marketing, Inc. (SEMI). The testimony supports SEMI's proposed Plan of Assignment for upstream pipeline assets utilized to serve customers on Atlanta Gas Light Company's system and my specific testimony addresses capacity management accounting and cost allocation issues, as well as benefits to consumers under SEMI's plan. A Hearing was held June 24-25, 2003 in Atlanta, GA.

South Carolina Electric and Gas Company
Before the Public Service Commission of South Carolina, Docket No. 2003-5-G. Prepared Direct Testimony filed September 16, 2003 on behalf of South Carolina Electric and Gas Company ("SCE&G"). The testimony (1) provides an overview of the natural gas markets, (2) describes how SCE&G purchases its reliable and diverse gas supply from South Carolina Pipeline Corporation ("SCPC"), (3) discusses SCE&G's utilization of SCPC's intrastate pipeline system, (4) describes SCE&G's responsibilities were it to purchase its own gas supply, and (5) concludes that SCE&G's gas supply during the review period was reasonable and prudent. A Hearing was held at the Commission in Columbia, SC on October 16, 2003.

South Carolina Pipeline Corporation
Before the Public Service Commission of South Carolina, Docket No. 2001-220-G. Prepared Direct Testimony filed January 21, 2002 on behalf of South Carolina Pipeline Corporation (SCPC). The testimony supports SCPC's cost allocation, cost classification, and natural gas transportation and storage rate designs as well as various pro forma adjustments to implement open access gas transportation. The testimony also supports various tariff proposals including stranded cost recovery and a term rate differential. In February 2002, SCPC withdrew its rate case application.

Before the Public Service Commission of South Carolina, Docket No. 2002-6-G. Delivered an oral presentation with slides on a "Review of Natural Gas Hedging Programs" on behalf of South Carolina Pipeline Corporation at a meeting of the Commission on December 19, 2002. The presentation provided a review of various Eastern U.S. gas companies' hedging programs along with an analytical approach to quantification of the appropriate amount to hedge.

State of Alaska - Department of Law
Before the State of Alaska Legislative Budget and Audit Committee and Senate Resources Committee, Interim Hearings – Alaska Natural Gas Pipeline Issues. Delivered an oral presentation with slides on June 16, 2004 in Anchorage, AK on the topic "What Agreements Must Be Reached Before the Federal Energy Regulatory Commission Weighs In on Tariff Issues." The presentation provided a review of the pipeline Open Season process, Precedent and Service Agreements, the FERC Certificate of Public Convenience and Necessity process and related regulatory requirements, and potential certificate conditions.

TXU Gas Distribution
Before the Railroad Commission of Texas, Docket GUD No. 9313, Petition for Review of TXU Gas Distribution From the Actions of the Cities of Arlington, et al.
Prepared Direct Testimony filed July 15, 2002 on behalf of TXU Gas Distribution (TXU). The testimony describes and explains TXU's cost allocation, rate design, and proposed new tariff provisions "Charge for Temporary Discontinuance of Service" and "Uncollectible Recovery Adjustment." Additionally, the testimony describes and supports the Company's proposed revised tariffs for gas service.

United Cities Gas Company
Before the Illinois Commerce Commission, Docket No. 00-0228. Prepared Direct Testimony filed February 17, 2000 on behalf of United Cities Gas Company, a unit of ATMOS Energy Corporation. The testimony described and supported a Class Cost of Service Study, declining block rate design, and weather normalization of sales and transport volumes.

Before the Virginia State Corporation Commission, Docket No._____. Prepared Direct Testimony filed July 6, 2000 on behalf of United Cities Gas Company, a unit of ATMOS Energy Corporation. The testimony describes and supports a Class Cost of Service Study, declining block rate design, and tariff revisions for temporary discontinuance of service and new customer connections.

Washington Gas Light Company
United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP83-137-000. Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 13, 1984. The testimony supported fully allocated cost-based rates for firm transportation service within a customer's contract entitlement and discounted interruptible transportation rates for service in excess of a customer's firm contract level. Rebuttal Testimony filed January 24, 1985.

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP82-55-000.
Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 9, 1983. The testimony addressed Transco's proposed minimum commodity bill, its proposed Fixed-Variable rate design, and its proposed redesign of small customer rates.

Before the Public Service Commission of Maryland, Case No. 7962.
Oral presentation made before the Commission at public hearings on gas transportation September 25-26, 1986. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company (WGL), and on behalf of Frederick Gas Company, Inc., a WGL subsidiary, filed on April 22, 1987. The testimony describes and supports proposed tariff provisions for firm and for interruptible delivery service by the companies and a proposed special purchases/sales rider for Frederick's low-priority interruptible gas sales. Rebuttal testimony subsequently filed as the case progressed.

Before the Public Service Commission of Maryland, Case No. 8060.
Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 1, 1988. The testimony describes and supports proposed tariff provisions and rates for interruptible delivery service and a margin-sharing tariff provision.

Before the Public Service Commission of Maryland, Case No. 8119.
Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 7, 1988. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed tariff changes to change or initiate turn-off and reconnection charges, service initiation fees, and rates and charges for unmetered gaslights. Rebuttal testimony was subsequently filed in the proceeding.

Before the Public Service Commission of Maryland, Case No. 8191.
Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 31, 1989. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed rate revisions for delivery service and for unmetered gaslight service and a proposal to retain margins on new interruptible services pending recovery of investment. Supplemental Direct Testimony was filed on June 16, 1989 to reflect actualized data for the test year.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIII. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 6, 1983. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period June 1983-November 1983 and the resultant cost savings to consumers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of June 20, 1984. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period December 1983-May 1984 and the resultant cost savings to consumers. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 11, 1984. The testimony describes the companies' participation in pipeline suppliers' special marketing programs and direct producer purchases during the period June 1984-November 1984. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 8509. Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of December 6, 1985. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1985-November 1985, the costs of which supplies were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment.

Before the Public Service Commission of Maryland, Case No. 8509(a). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing date of June 11, 1986. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1985-May 1986, the costs of which were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment and the testimony identifies and describes the company's participation in cases before the FERC.

Before the Public Service Commission of Maryland, Case No. 8509(c). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of May 7, 1987. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1986-May 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(d). Prepared Direct Testimony filed December 3, 1987 on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1987-November 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(j). Appeared as a supplemental direct witness at the hearing on November 30, 1990 to present oral testimony regarding the operation of the company's Firm Credit Adjustment mechanism and the computation of margins, particularly with respect to sales to Potomac Electric Power Company.

Western Kentucky Gas Company
Before the Public Service Commission of Kentucky, Case No. 99-070 (1999). Filed testimony on behalf of Western Kentucky Gas Company, a unit of ATMOS Energy Corporation, to describe and support a proposed Premises Charge to recover from new customers the incremental investment, and return and tax, associated with new residential customer hook-ups that is not otherwise recovered in base rates. The parties settled the case.

Publications and Research

"Calming Stormy Seas," (co-authored with Deepa Poduval) an article published in the November 2003 issue of American Gas, a monthly publication of the American Gas Association. The article discusses measures that utilities can utilize to reduce exposure to natural gas price volatility.

"Weather Risk Management for Regulated Utilities," (co-authored with Thomas Jenkin) an article published in the October 1, 2002 issue of Public Utilities Fortnightly, a publication of Public Utilities Reports, Inc. The article discusses methods of quantifying weather risk and options for managing the risk through the use of derivatives and weather normalized rates.

"Those Paper Pension Profits," an article published in the September 15, 2000 issue of Public Utilities Fortnightly, a publication of Public Utilities Reports, Inc. The article discusses the regulatory treatment of negative pension expense and offers strategies for managing the risk of pension expense credits being flowed-through in rates.

"How Stranded Are Your Assets?" an article published in the February 2000 issue of American Gas, a monthly publication of the American Gas Association. The article discusses strategies for utilities to ease the transition to a competitive, market-driven environment.

"The Electric Heat Pump," a paper analyzing the electric heat pump's competitive impacts in the metropolitan Washington, DC heating markets and competitive strategies, June 28, 1985.

Presentations and Speeches

American Gas Association's Advanced Regulatory Seminar:
"Current Rate Design Issues," a speech presented September 28, 1995.

"Local Distribution Rate Design Trends and Opportunities," a speech presented in October 1990 and updated and presented in 1991.

"Current Pricing Issues," a speech presented October 6, 1989.

"Can America Unbundle and Still Keep Warm?" a speech presented October 7, 1988.

"Flexibility in the Changing Market," a speech presented October 5, 1984.

American Gas Association Rate & Strategic Planning Committee Meetings:
"Distribution System Integrity Management," a speech presented April 12, 2005 in New Orleans, LA

"Natural Gas Fixed Price Tariff Options," a speech presented April 5, 2004 in Phoenix, AZ

"Improving Fixed Cost Recovery," a speech presented March 26, 2002.

"Impacts of Electric Generation on Native Gas Loads," a speech presented March 27, 2001 in Charleston, SC.

"Managing Upstream Resources in a Retail Unbundling World – FERC & Pipeline Perspectives and Responses," a speech presented April 4, 2000.

"Market Hubs – Operation, Economics & Rate Implications," a speech presented August 29, 1994.

"Implications of Capacity Release," a speech presented March 7, 1994.

"Implementing Restructuring," a speech presented March 15, 1993.

"Integrated Resource Planning Theory and Practice," a speech presented in April 1992.

American Gas Association Seminar "Service Innovations and Revenue Enhancements," Washington, DC:
"Improving Fixed Cost Recovery and Stabilizing Earnings – Drivers and Ideas," a speech presented December 12, 2002.

American Gas Association's Seminar "Competing in a Restructured World," Arlington, VA:
"Separation of Functions and Accounting Cost Standards," a speech presented July 9, 1998.

Energy Bar Association, Chicago, IL:
"Back to the Future – Managing Gas Supply in a Time of Price and Supply Uncertainty," a speech presented to the Joint Meeting of the Midwest and East Central Chapters, October 2, 2003.

National Association of Regulatory Utility Commissioners ("NARUC"):
"Natural Gas Fixed Price Tariff Options," a speech presented to the Staff Subcommittee on Accounting and Finance at Rapid City, SD, October 2, 2002.

"Design of Pipeline Rates," a teleconference speech concerning the design of rates for short-term service presented to the Staff Subcommittee on Gas, May 29, 1998.

Society of Utility and Regulatory Financial Analysts ("SURFA"):
"Perspectives on Weather Risk Management," a speech presented at Georgetown University Conference Center, Washington, DC, April 10, 2003

Southern Gas Association - Accounting Seminar:
"An Update on Customer Choice Programs and Related Accounting and Regulatory Issues," a speech presented in Houston, TX, July 9, 1999.

Texas Society of Certified Public Accountants – Natural Gas, Telecommunications and Electric Industries Conference, Austin, TX:
"Managing Energy Price Risk in a Volatile Environment," a speech presented April 19, 2004.

"Natural Gas Pricing and Rate Design in the 1990s," Seminar in Houston, TX:
"Rate Design Trends and Opportunities," a speech presented September 13, 1990.

"Pricing and Rate Strategies for Unbundled Services," Seminar in Houston, TX:
"Local Distribution Rate and Regulatory Trends and Opportunities," a speech presented October 30, 1990.

Training and Teaching Experience

American Gas Association's "Gas Rates Course", University of Wisconsin, Madison, WI:
"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in June, 1991 - 2004.

"Pipeline Cost Allocation and Rate Design," a lecture and hands-on computer demonstration presented June 6, 1995.

American Gas Association/Edison Electric Institute's "Introduction to Public Utility Accounting Course," Virginia Commonwealth University, Richmond, VA:
"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in May, 1991-1995.

STATE OF NORTH CAROLINA

VERIFICATION

COUNTY OF MECKLENBURG

Bill R. Morris, being duly sworn, deposes and says that he is Director of Financial Planning and Rates of Piedmont Natural Gas Company, Inc., that as such, he has read the foregoing Responses and knows the contents thereof: that the same are true of his own knowledge except as to those matters stated on information and belief and as to those he believes them to be true.

Bill R. Morris

Bill R. Morris

Sworn to and subscribed before me
this the 3 day of
February, 2006.

[signature]
Notary Public

My Commission Expires:

MY COMMISSION EXPIRES 10-29-10

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the Second Supplemental Responses of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc., to the Consumer Advocate and Protection Division's Second Set of Discovery Requests is being served upon the parties in this action either by hand delivery or by UPS overnight delivery addressed as follows:

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This the 3rd day of February, 2006.

James H. Jeffries IV