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UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION INCENTIVE PLAN (IPA) AUDIT	))) ( )	Consolidated Docket Nos. 01-00704 and 02-00850
UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION, PETITION TO AMEND THE PERFORMANCE BASED RATEMAKING MECHANISM RIDER	))))))	

RESPONSE OF ATMOS ENERGY CORPORATION TO THE CONSUMER ADVOCATE'S OBJECTIONS TO THE MOTION FOR APPROVAL OF SETTLEMENT AGREEMENT

Atmos Energy Corporation ("Atmos" or "the Company") provides this response to the Consumer Advocate's Objections to the Motion for Approval of Settlement Agreement. For the reasons set forth below, the joint motion for approval of settlement agreement filed by the Company and Authority Staff should be granted.

The objections filed by the Consumer Advocate and Protective Division ("CAPD") are divided into two general categories. First, the CAPD makes several procedural objections (which the CAPD's brief refers to as "threshold objections") regarding the progress of these consolidated cases and the manner in which the proposed settlement is being presented to the Authority for approval. Second, the CAPD sets forth, both in its brief and in the attached affidavits, its objections to the merits of the proposed tariff amendment contained within the terms of the settlement agreement This response will give a brief factual background of the history of these cases, and then address the CAPD's two categories of objections separately.

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I. FACTUAL AND PROCEDURAL BACKGROUND

The progress of these two dockets has been unusual. The complex procedural and factual background provides some explanation as to why the Company and Staff were forced to proceed in this somewhat unorthodox manner by presenting a motion to resolve both dockets at once.

The CAPD intervened in the audit case (Docket No. 01-00704) in May 2002. Shortly after the intervention, the parties began settlement negotiations. As part of those settlement negotiations, Atmos made substantially the same offer it is proposing in its motion - that it would withdraw its objections to the 2000 audit in exchange for implementation of the transportation index factor ("TIF") tariff ultimately set forth in Atmos' petition in Docket No. 02-00850.[1]

During the summer of 2002, it appeared the parties were close to an agreement. Atmos and the Staff were in agreement on all of the settlement terms. The CAPD agreed with the terms of the settlement, but would not agree to the effective date of April 1, 2001 for the new TIF tariff. The CAPD insisted that in addition to refunding all transportation savings for the 2000-2001 audit year, that Atmos also forego recovery of transportation savings for the 2001-2002 plan year, which would result in an additional loss to the Company of approximately $800,000. The CAPD's reasoning was that even though Atmos had not yet filed its annual report for 2001-2002, using the new TIF tariff for that plan year would amount to impermissible retroactive ratemaking. At the time of the settlement negotiations in the summer of 2002, the CAPD would however agree to an effective date of April 1, 2002 for the revised transportation calculations.

[1] The CAPD has waived any confidentiality these settlement negotiations may have had by revealing the content of the negotiations in previous filings in this docket. See CAPD Motion for Extension of Time to Motion to Consolidate and for Approval of Settlement Agreement, at p. 6. See Ray v. Richards, 2001 WL 799756 at *10 (Tenn. Ct. App. July 17, 2001) (noting that "Tennessee has long recognized a 'good-for-the-goose, good-for-the-gander' rule that if a party opens the door for the admission of incompetent evidence, he is in o plight to complain that his adversary followed through the door thus opened. ...") (internal citations omitted.)

Since the CAPD was not in total agreement with the settlement, the Staff elected not to finalize the agreement at that time.

Settlement negotiations continued Meanwhile, the Staff and the CAPD filed a motion for partial summary judgment in July 2002 which sought a ruling that transportation savings could not be included in the Company's incentive plan. The parties engaged in extensive discovery While discovery progressed, the Company filed the petition in Docket No. 02-00850 seeking implementation of the new TIF tariff as an alternative to the arguments presented in Docket No. 01-00704 The Company filed its response to the summary judgment motions in Docket No. 01-00704 in October 2002. The hearing officer denied the motions for summary judgment on March 31, 2003. In the meantime, settlement negotiations continued.

In June 2003, the parties agreed to mediate both cases in front of Chairman Tate. At that time, the only objection the CAPD was asserting to the proposed settlement was its position that the April 1, 2001 effective date on the TIF would constitute retroactive ratemaking. As such, Chairman Tate asked that both parties set forth their positions on that issue, including case cites, in mediation position statements that would not be shared with the opposing side. Before the mediation, the CAPD had taken the position it would agree to the settlement proposal if the effective date of the TIF were made April 1, 2002, which would force the Company to forego savings for two plan years - the audit year (2000-2001 - approximately $600,000 in savings) and the 2001-2002 plan year (approximately $800,000 in savings). At the mediation, the CAPD asserted that since so much time had passed since the last settlement discussions, the CAPD's position was now that the effective date of the TIF must be April 1, 2003, not April 1, 2002, which would force the Company to forego an additional plan year's savings (2002-2003 -

approximately $760,000 in savings) for a total of not two, but three plan years savings the Company would not recover. No settlement was reached at the mediation.

In September 2003, settlement discussions resumed again. The CAPD agreed in principal to an effective TIF tariff date of April 1, 2001 (the original date proposed by the Company), provided the percentage sharings be adjusted downward and that the TIF would be sunset after 4 years and re-examined at that time. Settlement discussions broke down when the CAPD requested that Atmos adjust the sharing percentages even lower, essentially gutting the Company's share of savings. All settlement offers were either rejected or withdrawn.

Having been unable to obtain the CAPD's agreement, despite repeated and prolonged settlement discussions, the Staff and the Company presented its proposal to the Authority. The proposal, contained in the joint motion, is the same agreement the Staff and Company reached in the summer of 2002. The proposal will render the issues in Docket 01-00704 moot and present the TIF tariff to the Authority for approval so that the CAPD can make its objections to the TIF tariff and a final determination can be reached. In its brief, the CAPD, for the first time, has presented objections to the merits of the proposed TIF beyond the assertion that an April 1, 2001 effective date constitutes retroactive ratemaking. The Company's response to those objections, as well as the CAPD's procedural objections is provided in the following sections.

II. THE CAPD HAS NOT BEEN PREJUDICED BY THE PROCEDURAL PROGRESS OF THESE CONSOLIDATED CASES.

A. The joint motion of the Company and Staff should not be denied merely because the CAPD has not joined in the settlement agreement.

The CAPD objects to the proposed settlement because the CAPD is not a party to the agreement, arguing that approval of the settlement agreement would be tantamount to forcing the CAPD to settle the matter. The Company and Staff are not proposing that the CAPD be forced to settle anything. The settlement agreement presented for Authority approval is not a compromise settlement of either of the dockets What the settlement agreement does is render one docket moot and present the other docket to the Authority for decision.

The settlement agreement does not force the CAPD to compromise Docket No. 01-00704, it simply renders that docket moot. Under the terms of the agreement, the Company will withdraw all its objections to the 2000-2001 audit presented in Docket No. 01-00704 and agree to refund to the consumers, with interest, all money collected under the disputed portions of the audit The CAPD has not objected to that portion of the settlement agreement, because it cannot. The Company is withdrawing its objections and accepting the Staff's positions regarding the audit. The CAPD intervened in Docket No. 01-00704 and took the precise same position as Staff with regard to the disputed portions of the audit. If Docket No. 01-00704 were litigated, the CAPD would not obtain anything more than it has under the agreement. Because the Company has agreed to withdraw its objections, there is nothing more to litigate in Docket No 01-00704, and the issues in that docket are moot

The agreement also does not force the CAPD to accept any compromise of Docket No. 02-00850 All the agreement does is present the petition in Docket No. 02-00850 to the Authority for approval, just as if there were no settlement agreement The only difference is that the settlement recites that the Staff agrees with the tariff proposed by the Company.

In summary, the Company and Staff are not asking that the CAPD be forced to settle anything They are merely presenting to the Authority a proposal that renders one docket (Docket No. 01-00704) moot and presents the second docket (Docket No. 02-00850) for Authority approval with both Company and Staff endorsement.

B. The CAPD is not being "punished" for participating in mediation.

The CAPD argues that approval of the Company and Staff joint motion would deprive it of the opportunity for discovery and hearing on the merits, in essence punishing the CAPD for participating in the mediation of these consolidated cases before Chairman Tate. Although the CAPD's response is not clear, it appears that the CAPD is arguing that it is being deprived of discovery and hearing in both Docket No. 01-00704 and Docket No. 02-00850. With regard to Docket 01-00704, the CAPD's argument is puzzling The only issue in Docket No. 01-00704 is the resolution of the Company's objections to the Staff's audit findings. The Company has withdrawn all those objections. The case is moot - there is nothing more to litigate. The Company's agreement to withdraw its objections gives the CAPD the full extent of what they were seeking - a full refund of the disputed amounts to the consumers. There is nothing to discover or hold a hearing about because the case has been resolved in the CAPD's favor. The CAPD's complaint that it has been deprived of discovery and a hearing in Docket 01-00704 is akin to a defendant who, upon the plaintiff's withdrawal of his complaint, complains that he was deprived of the opportunity to defend the lawsuit.

The CAPD's argument that it has been deprived of discovery and hearing in Docket No. 02-00850 is simply untrue. The hearing officer set a procedural schedule which allowed the CAPD to submit discovery requests, and a hearing is scheduled in this matter for June 8, 2004. This hearing and discovery is the same the CAPD would be afforded if Docket No. 02-00850 were not consolidated with Docket No. 01-00704 and no settlement agreement had been reached with Staff. The CAPD has repeatedly complained that it needs more discovery. The hearing officer allowed that discovery. The CAPD is now complaining that it needs still more discovery, yet the CAPD has yet to articulate what discovery it needs, nor explain why it failed to submit those discovery requests with the discovery recently served on the Company and Staff. The CAPD has not been deprived of any discovery nor of a hearing on the merits.

The CAPD also argues in its brief that the "harm" it has suffered as a result of participating in mediation is exacerbated by the fact that the mediation was also a judicial settlement conference under Tenn. Sup. Ct. Rule 31. As discussed above, the CAPD has suffered no harm as a result of the mediation. Regardless, the CAPD participated in and agreed to the selection of Chairman Tate as a mediator, and should not now be permitted to complain they were somehow harmed by their own decision.

C. The burden of proof has not been improperly shifted to the CAPD.

The CAPD also argues that the joint motion filed by the Company and Staff somehow shifts the burden of proof to the CAPD to prove the tariff proposed in Docket No. 02-00850 is not in the public interest. Both the Company and Staff have acknowledged repeatedly that they have the burden of proving that the motion should be granted. The tariff proposed in Docket No 02-00850 is being presented to the Authority for approval just as it would have been had there been no settlement or consolidation with Docket No. 01-00704. Without a motion, the Company would file its petition setting forth the proposed tariff and the grounds for approval of the tariff. The CAPD would have the opportunity to intervene and submit discovery. The CAPD would then be required to state its objections to the proposed tariff, and a hearing would be held on those objections with each side presenting witnesses and having an opportunity for cross-examination. In the case at hand, the motion sets forth the grounds the Company and Staff rely upon in support of the proposed tariff. The CAPD has had full opportunity to submit discovery on those grounds. There is a hearing scheduled where the parties will present testimony in support of their positions and have full opportunity to cross-examine the opposing side's witnesses The hearing officer will then issue a ruling. The CAPD has not explained how this procedure is any different than the procedure that would have been followed had there been no motion submitted. Instead the CAPD relies upon misdirection. On page 2 of its brief, the CAPD asks that the joint motion be summarily denied "since no testimony has been submitted...." The CAPD ignores the fact that a hearing has been scheduled for that very purpose. On page 9 of its brief, the CAPD argues that the joint motion cannot be granted unless the Company prevails on the heart of the issue in Docket 01-00704 - whether transportation savings were specifically provided for in the Company's original PBR plan. This argument is nonsensical. The Company has withdrawn all its objections made in Docket 01-00704, and there is nothing left to litigate. It does not matter whether the original plan provided for transportation savings because under the terms of the proposal, the Company is not seeking to recover any transportation savings under the original PBR. There has been no shifting of the burden of proof in this case.

D. Approval of the joint motion will not result in retroactive ratemaking.

The CAPD argues that granting the joint motion will result in retroactive ratemaking because the tariff proposed by the settlement agreement has an effective date of April 1, 2001 The CAPD's retroactive ratemaking argument is completely unfounded.

The general prohibition on retroactive ratemaking comes from the language of the statute granting the TRA's ratemaking authority, Tenn. Code Ann. § 65-5-201, which states that the TRA has the power to fix rates "which shall be imposed, observed and followed **thereafter**" (emphasis added). South Central Bell v. Tenn. Pub Svc. Comm'n, 675 S.W.2d 718, 720 (Tenn. Ct App 1984) In a case with similar facts as the matter at hand, the Tennessee Court of Appeals specifically held that allowing utilities to share in past earnings through prospective rate adjustments, as the proposed settlement does, does not constitute impermissible retroactive ratemaking. American Ass'n of Retired Persons ("AARP") v. Tenn. Pub. Svc. Comm'n, 896 S W.2d 127, 134 (Tenn Ct. App. 1994). In that case, the AARP argued that the telecommunication regulatory reform plan provision which allowed local exchange carriers to share in earnings in excess of a certain range was impermissible retroactive ratemaking 896

S W.2d at 134. The court held that the sharing plan did not result in retroactive ratemaking, noting that the rule called for the carriers to recoup past shared earnings through adjustments in future rates Id ; see also Consumer Advocate Division ex rel. v. Tennessee Regulatory Authority, 2000 WL 13794 at *3 (Tenn. Ct. App. Jan. 10, 2000) (holding that BellSouth's price regulation plan did not constitute impermissible retroactive ratemaking because the only rate changes under the plan would be prospective)

Under the settlement agreement between the Company and Staff, all agreed-upon losses and savings will be recouped by Atmos and the consumers the same as any sharing under the PBR plan - through adjustments in future rates. Under Atmos' PBR plan, 100% of the savings from all avoided costs, including savings from negotiated transportation discounts, are immediately passed through directly to the consumers through the Company's Purchased Gas Adjustment ("PGA") procedure When the Company negotiates a transportation discount, it subsequently files a PGA with the TRA to adjust consumers' rates to reflect the actual gas cost Atmos incurs. Atmos recoups its 50% share of those savings annually through a rate increase beginning each October 1, when the Company files its PBR factor true-up. Therefore, for example, when the Company negotiated the discount transportation contracts which became effective November 1, 2000, 100% of the savings from those contracts were passed through to the consumers through Atmos' periodic PGA filings. On October 1, 2001, Atmos filed its PBR true-up for the preceding PBR plan year. That true-up filing included a calculation of Atmos' share of the total amount of transportations savings for the preceding year (50% of the total savings). and divided that amount by the prior year's sales to arrive at a surcharge rate increase that would allow Atmos to recoup its share of the savings over the following year. The rate increase that was implemented on October 1, 2001 to allow Atmos to recover for all of the avoided costs (commodity and transportation) under both incentive mechanisms of the PBR was $0 00444 per ccf

Atmos has not filed any audit reports for audit years 2001-2002, 2002-2003 and 2003-2004. Obviously, because the Staff has yet to even begin the audits of the 2001-2002, 2002-2003 and 2003-2004 plan years, those audit years remain open Under the terms of the settlement agreement the refund to customers of the amounts collected for the 2000-2001 plan year will be accomplished through adjustments to future rates. The new tariff will begin effective April 1, 2001 (Day 1 of the year following the year at issue in Docket 01-00704) and Atmos will have 45 days to file its annual report for the following plan years. Any savings Atmos receives will, like the refund, be accounted for in adjustments to future rates.

The legal prohibition on retroactive ratemaking, therefore, places no impediment whatsoever to the parties agreeing on how the Company will calculate and report transportation cost savings when it eventually files its annual reports for those years This is precisely the arrangement that was specifically held valid in the AARP case discussed above, and there can be no question but that the contemplated procedure does not violate the prohibition on retroactive ratemaking. Indeed, if the settlement agreement constitutes impermissible retroactive ratemaking, then not only would the entire PBR and PGA true procedure be invalid, the Authority would not have the power to order Atmos to refund the amount at issue in Docket No. 01-00704 through adjustments in future rates.

This is not the first time the CAPD has taken a position with regard to retroactive ratemaking which elevates a hyper-technical objection to form over substance. The CAPD has dragged the retroactive ratemaking objection out in at least two previous cases appealed to the

Tennessee Court of Appeals, and the CAPD's approach on this issue has garnered scorn and disdain from the court.

In 1998, the CAPD appealed the TRA's order granting Nashville Gas Company a rate increase. Consumer Advocate Division v. Tennessee Regulatory Authority, 1998 WL 684536 at *3 (Tenn Ct. App. July 1, 1998). Among other objections, the CAPD argued that the TRA's order on the rate increase was invalid retroactive ratemaking. Id The TRA held the hearing on the rate increase on December 17, 1996. Id at *1. At that hearing, the TRA issued its ruling orally, and held that the new rates it had approved would go into effect January 1, 1997. Id. The TRA did not issue its written order on the ruling until February 19, 1997. Id. However, Nashville Gas notified the TRA in late December that it would implement the Authority's oral ruling and begin charging the new rates January 1, 1997 as specified. Id. The CAPD argued that Nashville Gas had no authority to implement the rate increase in January, and that the TRA's February 19, 1997 order amounted to retroactive ratemaking. Id. at *3.[2] The court summarily rejected CAPD's argument, noting that the retroactive argument "exalts form over substance." Id at *3

In 1996, the CAPD argued that the TRA's order requiring Kingsport Power Company to pass along to consumers any refund it received from its supplier due to a rate increase subsequently invalidated by the Federal Energy Regulatory Commission ("FERC") was impermissible retroactive ratemaking. Consumer Advocate Division v. Bissell, 1996 WL 482970 at *3 (Tenn. Ct. App. Aug. 28, 1996). Again, the Court of Appeals rejected the CAPD's

[2] The CAPD also argued that the rate increase petition had not been pending for the requisite amount of time because it was filed shortly before the legislature abolished the Public Service Commission and replaced it with the TRA, and the case had to be refiled shortly after the TRA was created Consumer Advocate Division, 1998 WL 684536 at *3 The court rejected this argument as well, holding that the refiling was "caused by a massive overhaul of the state regulatory machinery," a fact that could not be attributed to Nashville Gas Id

retroactive argument, noting that the refund was the final step in a federally mandated ratemaking scheme. Id at *3. The court also expressed puzzlement over CAPD's position, noting that if CAPD were correct that the refund constituted retroactive ratemaking, the logical conclusion would be that Kingsport Power would keep the refund it received from its supplier, thus resulting in a windfall to the company at the expense of the ratepayers. Id.

Like the cases discussed above, the CAPD's retroactive ratemaking objection in this matter is without any legal basis whatsoever

III. THE CAPD'S OBJECTIONS TO THE MERITS OF THE PROPOSED TARIFF ARE UNFOUNDED.

A. The 2003 FERC order cited in the CAPD's brief has no relevance whatsoever to the issues in these consolidated cases.

The CAPD's brief contends that the joint motion proposes "a path regarding transportation contracts which is clearly incongruent with the approach of the Federal Energy Regulatory Commission ("FERC") described in its July 25, 2003 order." (CAPD Brief p 9.) The CAPD's brief provides no discussion of the allegedly relevant holdings or discussion in the referenced FERC order. It appears the CAPD is relying solely on the assertions of Dr. Stephen Brown's affidavit, which curiously, does not even include the FERC order itself among the 40 odd pages of exhibits attached to his affidavit. Dr. Brown contends in his affidavit that in the 2003 order, FERC determined that negotiated rates where not in the public interest, and that order constitutes a "general reversal" of FERC's 1996 policy of allowing such negotiated rates. (Brown Aff. ¶ 8.) Dr Brown's contention is absolutely false.[3] In fact, even the most superficial

[3] Even if Dr Brown's reading of the 2003 FERC order were correct which it is not, the contention that FERC has found negotiated transportation discounts to be contrary to the public interest is directly contrary to the CAPD's assertion that consumers will receive nothing of value from the settlement because "Atmos is under an obligation to meet the needs of consumers at the lowest possible gas cost " (CAPD Brief p 10. McCormac Aff ¶ 5) It appears Dr Brown is arguing that Atmos should not pursue transportation discounts because FERC has found them "contrary to public interest," while Mr McCormac is arguing that Atmos should pursue the discounts, but not share in any savings

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perusal of the 2003 FERC order reveals that there is no conceivable way the 2003 FERC order could be read as making such a finding.

Contrary to Dr Brown's assertions, the 2003 FERC order does not reverse its negotiated rate policy, but actually does just the opposite - the 2003 order reaffirms the policy's effectiveness and specifically rejects one industry commentator's suggestion to eliminate the negotiated rate policy altogether. (FERC Order, attached hereto as Exhibit 1, at ¶¶ 10, 4) (stating that "[t]he Commission finds that its negotiated rate program has been generally successful in providing flexible, efficient pricing of pipeline capacity while mitigating pipeline use of market power by means of a recourse rate ") What the 2003 order does do is find a potential for pipeline manipulation under one very specific type of pricing mechanism - basis differential pricing - and disallow that particular pricing mechanism.[4] (FERC Order ¶ 16, stating that "[t]he Commission has determined to modify its negotiated rates policy and will no longer permit the use of gas basis differentials to price negotiated rate transactions.")[5] Basis differential pricing is the practice of pricing transportation services based on the difference between the commodity gas price at two different points. (FERC Order ¶ 16.) None of Atmos' discounted transportation contracts employ the basis differential pricing mechanism. (Aff. of R. McDowell, attached hereto as Exhibit 2, ¶ 4) Therefore, the manipulation risk the FERC was concerned about and discussed in the paragraph quoted[6] in Dr Brown's affidavit simply does not exist for Atmos' discounted contracts.[7] As such, the 2003 FERC Order has no relevance whatsoever to the issue

[4] The 2003 FERC Order also changes pipeline filing requirements, none of which are relevant to the issues at hand

[5] See also, FERC Order Dissent of Commissioner Brownell, ¶1, stating that "[I]n this order, the majority prohibits on a prospective basis the use of gas basis differentials to price negotiated rate transactions "

[6] Dr Brown cited the portion of the FERC order quoted in his affidavit as paragraph 22 The text is actually contained in paragraph 20 of the FERC order

[7] Dr Brown's argument doesn't even make sense in theory Even if Atmos did use basis differential pricing, the

of whether Atmos should be able to share in savings resulting from discounted transportation contracts. Dr Brown's contentions to the contrary, and the out-of-context quote cited in support of his contentions reveal either a patent misunderstanding of the FERC order and the gas supply industry as a whole, or a blatant attempt to mislead the Authority.[8]

B. The CAPD's assertion that the consumers will not receive any benefit from the settlement is untrue.

The CAPD objects to the proposed settlement agreement and new TIF tariff on the grounds that the consumers will receive nothing of value. The CAPD's allegation is simply untrue. The CAPD conveniently ignores the fact the settlement includes an immediate refund, with interest, of all transportation savings the Company was able to negotiate for the 2000-2001 audit year, an amount which totals approximately $629,000. In addition, under the new TIF tariff, the consumers receive the benefit of the savings generated from the discounts Atmos has negotiated, 50% of which goes directly to the consumers under the sharing mechanism. If Atmos is not permitted to share in the savings from transportation discounts, not only does the Company have no incentive to obtain the discounts, the PBR actually provides an incentive for the Company to opt for higher transportation costs in exchange for lower commodity costs, which could result in consumer bills which are higher overall.

The PBR was designed to create an incentive for Atmos to out-perform the market in its acquisition of gas supplies by allowing the Company to share in savings obtained and help

manipulation FERC was concerned about was situations where the pipeline would withhold capacity to drive ***up*** the difference between the commodity price at the two points and thus ***increase*** the transportation costs Such manipulation would result in less savings for Atmos. or could eliminate any savings whatsoever, if the price were to exceed the maximum FERC rate benchmark In any event, the potential for this type of manipulation is eliminated by the terms of the FERC order itself, which disallows basis differential pricing

[8] The CAPD also cites the 1998 testimony of J D Woodward from the original PBR docket and argues the testimony somehow supports the CAPD's position that Atmos should not be able to share in the savings resulting from the transportation discounts negotiated in 2000. It is unclear how Mr Woodward's testimony could possibly support the CAPD's position. given that the testimony predates the existence of transportation discounts altogether It is obvious the testimony is taken out of context

absorb excess costs (Phase Two Order p. 2.) A fundamental requirement of the PBR is that Atmos is not to be rewarded at the expense of the ratepayer. In order to satisfy the incentive principle behind the PBR, as recognized in the Phase Two Order, the program must be all-inclusive, e g. it must include all aspects of gas purchasing activities. If transportation costs are excluded from the PBR program and simply passed on in full to the consumers, the PBR plan would have a material defect. Atmos could increase its savings on the commodity portion, which it would share in, by entering into relatively high transportation cost arrangements (which would be passed on to the ratepayer) in order to lower commodity costs. Under this scenario, Atmos could earn benefits at the ratepayers' expense. This is completely inconsistent with the goals of the PBR program, and does not benefit the consumers. The benefit the consumers will receive from the proposed settlement is twofold: (1) consumers will receive a refund of $629,000, which represents the full amount of savings the Company generated from transportation discounts in the 2000-2001 plan year, plus interest; and (2) the new TIF tariff proposed by the joint motion will provide an incentive for Atmos to enter into contractual arrangements which will result in the lowest possible bills for consumers.

C. The CAPD's assertion that the maximum FERC rate is an inappropriate standard of performance is incorrect

The CAPD objects to the new TIF tariff on the grounds that the maximum FERC rate, which is the standard by which savings are measured under the tariff, is not an appropriate standard of performance. The CAPD claims that no appropriate market standard exists for transportation costs, and therefore, savings cannot be accurately measured. The CAPD is incorrect

Contrary to the arguments of the Staff and CAD, the maximum FERC rate is an appropriate indicator of market transportation prices, and in fact, has been accepted in other states as the benchmark true market indicator of transportation costs. (Creamer Aff. ¶ 15 filed in Docket No. 01-00704, attached hereto as Exhibit 3.)

During the experimental PBR period, all of Atmos' actual transportation costs were at the undiscounted published maximum FERC rate. (Creamer Aff. ¶ 11.) During the fall of 1999, discounted transportation contracts for the first time became a feature in the marketplace, and Atmos, based on the incentives of the PBR, began to aggressively pursue those discounts. (Creamer Aff. ¶ 11, 16.) The discounts Atmos negotiated in its transportation contracts are uncommon, and must be aggressively pursued. (Creamer Aff. ¶ 16.) They are not routinely available just for the asking. (Creamer Aff. ¶ 16) Atmos devoted a substantial amount of resources to negotiating these discounts, and had to expend considerable effort to be successful (Id.) The discounts were not simply granted as a result of Atmos' request. (Id.) One reason Atmos invested so much time and effort into negotiating the discounted transportation rates was because of the incentives provided under the Company's PBR tariff. If Atmos did not think it would be able to share in the savings it obtained through the negotiations, the Company would not have expended so much effort in negotiating the contract, but would have focused its resources in more profitable areas.

Discount transportation rates are far from standard in the industry. For example, Atmos Energy as a whole has been unsuccessful in obtaining transportation discounts from the majority of the available pipelines. (Creamer Aff. ¶ 16.) Atmos has been able to negotiate discounts on its contracts for only 2 of the 28 pipelines it contracts with. (Id.) Only 3 of the 6 pipelines serving Atmos territory even offer any discounts on their contracts. (Id.) Atmos has been successful in negotiating discounts on 6 of the 16 pipeline contracts it holds, while the remaining 10 contracts remain at the maximum FERC rate. (Id.) Atmos negotiates these discounts off the maximum FERC rates, not off of commodity-based indexes. (Creamer Aff. ¶ 15.) The fact that the vast majority of contracts are at the maximum FERC rate demonstrates that the maximum FERC rate is the standard in the market, and that Atmos had to expend considerable effort to negotiate discounts. (Id. at ¶ 16.)

Furthermore, the maximum FERC rate is the only available market index for transportation costs. (Id. at ¶ 19.) If, as the CAPD contends, transportation costs should not be included in the PBR, the Authority would be forced to conduct a prudency review of the Company's transportation costs, which would necessarily be based on the maximum FERC rates. (Id. at ¶ 15.) Therefore, the maximum FERC rate is the appropriate market indicator to use to measure transportation savings.

D. The TIF will not reward the Company for practices that will harm consumers.

In its brief, the CAPD relies on the Affidavit of Dan McCormac to argue that implementation of the TIF tariff will reward the Company for behavior that would actually harm consumers. Mr McCormac's argument is that the Company will opt to purchase higher cost gas in order to obtain the transportation savings, thus resulting in higher prices for consumers. Mr. McCormac poses a hypothetical where the Company would opt to purchase from Henry Hub for $5.50 delivered cost even though the gas could be purchased in Murfreesboro (in a purchase without a transportation component) for the same delivered cost. However, Mr. McCormac's hypothetical is overly simplistic and does not reflect the realities of the Company's gas supply purchases. Even assuming the total delivered cost for the two purchases would ever be the same, which Mr McCormac does not establish, the hypothetical ignores additional considerations the Company must take into account in making purchasing decisions, including operational, reliability, and safety concerns. (McDowell Aff ¶ 5.) Purchases without a separate transportation component like the "Murfreesboro" example cited in Mr McCormac's affidavit are not generally backed by primary firm transportation and therefore may not be available on critical days. (Id.) In order to meet its service obligations, the Company follows a general practice of subscribing to the more reliable primary firm transportation. (Id.) Even assuming the Company's choice to use primary firm transportation could ever result in a higher ultimate cost for the consumer, the higher price would not be incurred because of the Company's desire to recoup transportation savings, but because of the Company's obligation to provide reliable and safe service

What the CAPD does not address is the fact that without a mechanism like the proposed TIF tariff to allow the Company to share in transportation savings, the Company would be rewarded at the expense of the ratepayer. If transportation costs are excluded from the PBR program and simply passed on in full to the consumers, the PBR plan would have a material defect. The Company could increase its savings on the commodity portion, which it would share in, by entering into relatively high transportation cost arrangements (which would be passed on to the ratepayer) in order to lower commodity costs Under this scenario, the Company could earn benefits at the ratepayers' expense. This is completely inconsistent with the goals of the PBR program, and explains why the TIF tariff is necessary.

E. The TIF tariff is not inconsistent with previous TRA rulings.

The CAPD, through the affidavit of Dan McCormac, argues that the proposed TIF tariff is somehow inconsistent with the Authority's recent interpretation of the PGA rule in Docket No. 03-00209 (the "Uncollectibles Docket"). In that docket, the Authority ruled that the definition of gas cost in the PGA rule included cost incurred because of bad debt. (Order in Docket No. 03-00209.) Despite Mr McCormac's pejorative characterization of the ruling as a "change in ratemaking policy" that "force[s] consumers to bear 100%" of the gas costs, the ruling actually reaffirms a ratemaking policy that has been in place since 1970 The ruling the Uncollectibles

Docket has no relevance whatsoever to the question of whether the Company should be able to share in savings from transportation discounts under the PBR. It is true that 100% of gas costs are passed through to consumers, but that is because of the PGA rule itself, which was implemented in 1970. The operation of the PGA rule does not run counter to allowing the Company to share in transportation savings, but actually provides more evidence that the proposed TIF is necessary. According to Mr. McCormac, because 100% of gas costs are passed through to consumers under the operation of the PGA rule, the Company has no incentive to control those costs, absent the incentives provided under the PBR. Thus, based on Mr. McCormac's own reasoning, if transportation costs are excluded from the PBR, the Company has no incentive to undertake the significant amount of effort it has expended in order to obtain a reduction of those costs through negotiated discounts.

Mr McCormac apparently would advocate a return to the 1960's era ratemaking, where, instead of a PGA rule, gas costs were included in base rates and instead of the incentives provided by the PBR plan, the Authority conducted regular prudency audits. Mr. McCormac's personal views aside, the issue currently before the Authority is whether the proposed TIF tariff is just and reasonable As discussed in detail above, and as the TRA Staff agrees, the tariff is just and reasonable and should be implemented.

F. The CAPD's accusation that the Company has somehow participated in manipulation and fraudulent practices is without any support whatsoever, and should not be taken into consideration in this matter.

In the last paragraph of his affidavit, Mr. McCormac essentially accuses the Company of fraud without any support whatsoever. He recites what he claims are "recent events" in the industry as a whole, including a myriad of fraudulent practices. Nowhere does Mr. McCormac provide any evidence whatsoever that such events have occurred at all, much less that Atmos has participated in any of the fraudulent practices. Mr. McCormac's allegations are nothing more than spurious and transparent mudslinging. Mr. McCormac's unsupported musings should not be taken into consideration in this matter.

IV. CONCLUSION.

The CAPD has not been prejudiced by the procedural progress of these consolidated cases. The objections the CAPD has raised to the proposed TIF tariff on the grounds of retroactive ratemaking and the 2003 FERC order are unfounded The proposed TIF tariff employs an appropriate benchmark for measuring savings and is consistent with the previous rulings of the Authority. The Company has established and will establish at hearing that the settlement and proposed tariff are just and reasonable and in the public interest As such, the Company requests that its joint motion with Staff for approval of the settlement agreement be granted.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served via U S. Mail, postage prepaid, upon the following this the 21st day of May, 2004:

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104 FERC 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell

Natural Gas Pipeline Negotiated Rate Policies and Practices — Docket No. PL02-6-000

MODIFICATION OF NEGOTIATED RATE POLICY

(Issued July 25, 2003)

1 This order addresses the Commission's Negotiated Rate Policy and concludes that several modifications of that policy are necessary in order to continue to permit the flexible, efficient pricing of pipeline capacity in a transparent manner, while ensuring the mitigation of market power.

Background

2. In 1996, the Commission issued its Policy Statement concerning negotiated rates.[1] In summary. this policy, as modified by Order No 637,[2] permitted interstate pipelines

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[1]The Commission's current policies were originally established in, Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Regulation of Negotiated Transportation Services, Statements of Policy and Comments, 74 FERC ¶ 61,076 (1996), order on clarification, 74 FERC ¶ 61,194 (1996), order on reh'g, 75 FERC ¶ 61.024 (1996)

[2]Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services, FERC Stats. & Regs. Regulations Preambles (July 1996-December 2000) ¶ 31,091 at 61,343 (2000) (Order No. 637); order on rehearing, Order No. 637-A, FERC Stats. & Regs, Regulations Preambles (July 1996-December 2000) ¶ 31,099 at 31,648 (2000) (Order No. 637-A), and Order No. 637-B, 92 FERC ¶ 61,062 (2000) (Order No 637-B), aff'd in part and remanded in part,
(continued...)

under Part 284 of the Commission's regulations to negotiate rates with a shipper that vary from the otherwise applicable cost of service pipeline tariff, subject to certain limitations, such as the Commission's prohibition against pipelines negotiating terms and conditions of service.[3] Moreover, under the Commission's policy, pipelines must permit shippers to opt for use of a traditional cost of service "recourse" rate instead of requiring them to negotiate for rates for any particular service.[4] The Commission determined that the availability of a recourse rate would prevent pipelines from exercising market power by assuring that the customer can fall back to cost-based, traditional service if the pipeline unilaterally demands excessive prices or withholds service.[5]

3 On July 17, 2002, in Docket No. PL02-6-000, the Commission issued a Notice of Inquiry (NOI) concerning its Negotiated Rate Policy.[6] There, the Commission stated that it was undertaking a review of issues related to its negotiated rate program and requested comments from, and posed questions to, the gas industry regarding the Commission's negotiated rate policies and practices. The Commission has received responses from all segments of the gas industry that raise a variety of issues related to the Commission's

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[2](continued)
Interstate Natural Gas Association of America v. FERC, 285 F.3d 18 (D.C. Cir. Apr. 5, 2002), Order on Remand, 101 FERC ¶ 61,127 (2002).

[3]The Commission has determined that negotiated terms and conditions of service include any provisions that result in a customer receiving a different quality of service than that provided other customers under the pipeline's tariff. Dominion Transmission, Inc , 93 FERC ¶ 61,177 (2000) The Commission will, however, permit the implementation of negotiations resulting in deviations from the pipeline's form of service agreement, so long as such changes do not change the conditions under which service is provided and do not present an undue risk of undue discrimination. Columbia Gas Transmission Corp., 97 FERC ¶ 61,221 at 62,001-02 (2001).

[4]See Natural Gas Pipeline Co. of America,101 FERC ¶ 61,125 (2002) (finding that a pipeline may not restrict the use of recourse rate bids and, thereby. deprive bidders of a cost of service rate alternative, by declaring that only negotiated rate bids would be considered valid for bidding in an open season to determine interest in a pipeline expansion project)

[5]74 FERC ¶ 61,076 at 61,240.

[6]Notice of Inquiry Concerning Natural Gas Pipeline Negotiated Rate Policies and Practices, 100 FERC ¶ 61,061 (2002).

negotiated rate policies[7] As discussed below, upon consideration of its experience with the existing negotiated rate program, and the comments received from the industry in the NOI proceeding, the Commission has determined to modify several aspects of its Negotiated Rate Policy.

Discussion

4 The Commission finds that its negotiated rate program has been generally successful in providing flexible, efficient pricing of pipeline capacity while mitigating pipeline use of market power by means of a recourse rate. This view is supported by the majority of commenters as they support the negotiated rates program and want it to continue However, certain commenters suggest various changes to increase transparency of the negotiated rates and methodologies for limiting pricing options for negotiated rates. The Commission has reviewed these comments and has determined to revise its filing requirements to increase the transparency of negotiated rates in order to minimize the potential for discrimination In addition, the Commission has determined to address the pricing mechanisms permitted under negotiated rates in order to ensure adequate mitigation of any pipeline market power The Commission will begin its discussion with a consideration of the use of natural gas based index prices, in particular, the use of such indices to determine basis differentials, as a pricing methodology for the negotiation of rates

<u>**Gas Index Pricing Mechanisms**</u>

5. In its Policy Statement, the Commission set forth a mechanism by which a pipeline that does not attempt to establish a lack of market power to justify market-based rates and does not wish to embark on an incentive rate program, may seek a negotiated rate alternative to traditional cost of service ratemaking and thus achieve flexible, efficient pricing The Commission determined that, under this policy, the availability of a cost of service based recourse rate would protect shippers from the exercise of any market power by the transporters. As such, in its efforts to permit parties to establish flexible, efficient pricing for transportation service, the Commission did not seek to limit mechanisms used in transportation price negotiations.

6. Since the establishment of this policy, pipelines have availed themselves of the flexibility of the Commission's policies to negotiate many different types of pricing mechanisms. These have included negotiated rates for transportation based upon gas

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[7]See Appendix for list of commenters.

commodity price indices. These gas commodity price indices, when used as a negotiated pricing mechanism, usually reflect gas prices at different points such as at natural gas production basins or certain receipt and delivery points and citygates This transportation pricing mechanism is based upon the difference between the gas price indices at the two points that is commonly referred to as the basis differential. The foundation for this pricing mechanism is that the difference in price between two points, as shown by the respective price indices, reflects the value of transportation between the two points.

7 Several commenters oppose the use of basis differentials as a pricing mechanism for negotiated transportation rates.[8] Those opposed to the use of such pricing mechanisms argue that the use of such basis differentials in establishing transportation prices leads to rates far in excess of the recourse rate; gives the pipeline an interest in the commodity price of gas, and permits shippers to lock-in a profit margin and mitigate price risk, which provides increased price protection not available to recourse shippers.

8. IPAA states that the fundamental problem with negotiated transportation rates is that they tempt pipeline monopolies with negotiated rate authority to focus more attention on the opportunity to market gas than on their statutory obligation to provide non-discriminatory transportation. On this general note, the Industrials argue that negotiated transportation rate deals based on price differentials give pipelines a stake in the commodity price of gas on a particular day or at a particular location, thus effectively allowing pipelines to re-enter the gas commodity sales business. CPUC adds that transportation rates based upon commodity sales prices allow the pipeline to capture part of the commodity gas price and essentially makes it a partner in a merchant transaction. Mirant also asserts that index- based deals allow pipelines to compete directly with shippers in commodity markets.

9. Oklahoma and NASUCA argue that the use of basis differentials for negotiating transportation rates at best operates as a contractual mechanism to make additional profits, and at worst, operates as an incentive to withhold capacity. BP adds that such contracts provide an incentive for the pipeline to maximize revenue by selling any unutilized firm transportation as interruptible transportation and competing against the shipper's capacity As such, it argues that this type of arrangement gives the pipeline an incentive to withhold operationally available capacity from the market for the purpose of increasing the commodity basis differential. Mirant states that the shippers and pipelines are not on an equal footing, because of the pipeline's control over capacity, the pivotal

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[8]See generally, comments of Oklahoma, Mirant, CPUC, NASUCA, BP, IPAA, and Calpine.

component of such trades. In addition, Mirant states that pipelines may have more information regarding the factors leading to differentials between index prices and may actually be able to influence such differentials through the operation of their systems.

10. CPUC opposes the use of negotiated rates in general and index-based rates in particular CPUC states that evidence indicates that the California energy markets have been manipulated by traders and that spot market published commodity indices are not verifiable. Therefore, CPUC argues that it is unreasonable to continue the use of negotiated rates in place of tariff rates to serve markets or to simulate market behavior.

11. Other commenters argue that the Commission should continue to permit the use of basis differentials as a mechanism by which to set negotiated transportation rates. In essence, they maintain that these pricing methodologies represent a reasonable proxy for the value of the transportation and that the indexed rates allow shippers to easily engage in hedging programs and gas supply cost-management.[9] For example, INGAA argues that there is a relationship between the unregulated gas commodity price and the value of a pipeline's transportation, and that to achieve the Commission's goals of price transparency and market efficiency, the Commission should not place unwarranted restrictions on the ability to negotiate rates using basis differentials. INGAA argues that there is nothing inherently wrong about rates that reflect this market reality and that such rates protect shippers because the rate cannot exceed the basis differential.

12. The KM Pipelines and Williams argue that the Commission has recognized, in the context of evaluating the lifting of price caps in the short-term secondary market for released capacity, that basis differentials reflect the value placed by the market on the transportation capacity. Peoples and Duke Trading state that the price differential between points is a commonly accepted proxy for the value of transportation between such points. In the same vein, the KM Pipelines assert that, whether index-based pricing is permitted or not, the expected level of basis differentials will be a fundamental underlying consideration in contracting and. therefore, eliminating this pricing mechanism will not change the basic dynamics of the transaction

13. Many commenters argue that the Commission should assume that most shippers that negotiate rates are sophisticated market participants, and that the Commission should not get involved in the pricing of such transactions beyond ensuring that the shipper

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[9]See, e.g., Comments of Alliance, ProLiance. Dominion, KM Pipelines, KeySpan, AGA, Peoples, EnCana, APSA, Northern Natural, MidAmerican, El Paso, Williston Basin. TransColorado, INGAA, Peoples, Duke Trading, Williams, EPSA and NGSA.

always has the option of taking the recourse rate [10] The AGA states that flexible and creative negotiations should not be inhibited by proscriptions against certain types of transactions such as those predicated on basis differentials. MidAmerican adds that deals based upon price differentials are no different than fixed price negotiated rate deals, because in either circumstance, the shipper can always revert to a recourse rate. EPSA, Dominion, NGSA and Alliance argue, in essence, that restrictions on the types of rates that can be negotiated may unnecessarily reduce flexibility and the value of the program.

14. Williston Basin, TransColorado and EnCana maintain that it is difficult for pipelines to manipulate hub prices to increase profits. They assert that while the risk of manipulation is low, the potential benefits to shippers and pipelines are high, and shippers are more willing to acquire capacity when they can share the risk with the pipeline.

15. The Canadian Association of Petroleum Producers (CAPP) argues that the Commission should allow indexed-based rates, but that the Commission should ensure that pipelines entering into such arrangements do not withhold capacity from the market in order to affect commodity prices CAPP asserts that the popularity of indexed rates demonstrates their appeal and that to prohibit them would potentially undermine the purposes of the negotiated rate program KeySpan asserts that negotiated rate frameworks, such as those based on gas price differentials, respond to the needs of shippers and consumers and that there is no risk associated with these pricing structures that is not outweighed by their potential benefits.

Discussion of Basis Differential Pricing Mechanisms

16. The Commission has determined to modify its negotiated rates policy and will no longer permit the use of gas basis differentials to price negotiated rate transactions. Gas commodity price indices, when used as a negotiated pricing mechanism, usually reflect gas prices at different points, such as at gas basins or certain receipt and delivery points and citygates The pricing mechanism is based upon the difference between the gas price indices at the two points. As discussed above, the basis differential pricing mechanism uses the difference in gas prices between two points, to reflect the value of transportation between such points. Thus, under this mechanism, the wider the difference between the points, the greater the value of the transportation. In the Commission's view, allowing the use of gas commodity basis differentials by a pipeline as a mechanism for pricing transportation by a pipeline with market power threatens the Commission's regulatory

[10] See, e g , Comments of NEG, El Paso. Peoples, Encana, WDG, MidAmerican and Alliance.

structure for the transportation of gas as well as the Commission's attempts to improve and maintain a competitive natural gas commodity market.[11] This is because such mechanisms provide pipelines with an incentive to withhold capacity in an attempt to manipulate the gas commodity market by widening the differences between the indices.

17 In Order No 637, the Commission discussed how its policies under traditional cost of service rate regulation limit the pipeline's market power stating:

> The principal reason for limiting pipeline rates to a level that would permit recovery of a pipeline's annual revenue replacement is to limit the ability of the pipelines to exercise market power, so that the pipeline does not charge excessive rates. Without rate regulation, pipelines would have the economic incentive to exercise market power by withholding capacity (including not building new capacity) in order to raise rates and earn greater revenue by creating scarcity. Because pipelines are regulated, however, there is little incentive for a pipeline to withhold capacity, because even if it creates scarcity, it cannot charge rates above those set by its

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[11]In Order No 636, the Commission reviewed the House Committee Report leading to the Natural Gas Wellhead Decontrol Act of 1989, [Pub. L. No. 101-60, 103 Stat.157 (1989)], which stated that the Commission's competitive open-access pipeline system should be maintained and that:

> The Committee stresses that these new rules, and especially the wide adoption of blanket certificates for nondiscriminatory open access interstate transportation of non-pipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and to obtain shipment of its gas to them on even terms with other supplies. Order No 636 at 30,397, H.R. Rep. No. 29 101st Cong 1st Sess., at p 6.

In addition, the Commission noted that the House Committee Report urged the Commission "to retain and improve this competitive structure in order to maximize the benefits of decontrol." Id. (emphasis in original)

> cost of service. Since pipelines cannot increase revenues by withholding capacity, rate regulation has the added benefit of providing pipelines with a financial incentive to build new capacity when demand exists [12]

18 Subsequently, in Tennessee, the Commission examined the pipeline's incentive to withhold capacity in spite of the Commission's Part 284 regulations prohibiting such action and determined that its traditional cost of service regulation that does not permit the pipeline to charge more than the maximum cost of service rate provided an adequate check on such incentives.[13]

19. However, the Commission's negotiated rate policy permits pipelines to charge rates above the maximum cost of service rate thus presenting the possibility that a pipeline could increase revenues by withholding capacity. The Commission has relied on the availability of recourse service to prevent such an exercise of market power "by assuring that the customer can fall back to cost-based traditional service if the pipeline unilaterally demands excessive rates or withholds service."[14] As a general matter, this should be sufficient to prevent the pipeline's exercise of market power, since ordinarily a shipper would be expected to choose the recourse rate in preference to a significantly higher negotiated rate.

20. However, this may not be true where the negotiated transportation rate is tied to the commodity price of gas. Such a negotiated rate may render the shipper indifferent to the actual costs of transportation. For example, a shipper may agree to an index differential-based, negotiated transportation rate with a pipeline. The shipper may then enter into gas sales agreements with its customers based upon the downstream price index that, in effect, lock in this transportation rate and/or a profit on the transaction. As a result, the shipper is indifferent to the price of gas at the downstream point and the pipeline's withholding of capacity to manipulate the downstream commodity gas price (and the effect of such manipulation on the negotiated transportation rate). It has, in effect, shifted the possible risks of the pipeline's abuse of its market power to the gas commodity market as a whole In other words, negotiated transportation rates that use

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[12]Order No 637 at 31,270

[13]Tennessee Gas Pipeline Co., 91 FERC ¶ 61,053 at 61,191 (2000), order on reh'g, 94 FERC ¶ 61,097 (2001), aff'd, Process Gas Consumers Group v. FERC, 292 F.3rd. 831 (D.C. Cir 2002) (Tennessee)

[14]74 FERC ¶ 61.076 at 61,240.

basis differentials to price transportation give the pipeline an incentive to withhold capacity so as to widen the basis differentials In addition, the shipper may have little incentive not to agree since it is either held harmless or may, in fact, share in the profits from the increased price differential.[15]

21. In Order No. 636, the Commission stated that its primary goal was to improve the competitive structure of the natural gas industry and, at the same time, maintain adequate and reliable service The Commission stated that its intent was to further "facilitate the unimpeded operation of market forces to stimulate the production of natural gas . . .. "[16] The Commission thus undertook the task of improving the benefits of the decontrol of natural gas prices -- chiefly, abundant gas supplies at lower prices -- through the maintenance and improvement of its competitive pipeline transportation system. To permit pipelines to utilize pricing mechanisms, such as those based upon natural gas commodity prices, which create powerful incentives for the pipelines to attempt to use their monopoly power to manipulate the prices of the competitive natural gas commodity market, is contrary to the Commission's goal of improving the competitive pipeline transportation system set forth in Order No. 636.[17]

22. Pricing mechanisms that invest pipelines with an incentive to use market power to manipulate the commodity price of gas hinder the Commission's attempt to maintain and improve the competitive natural gas market. To allow pipelines to acquire an interest in commodity prices, or more precisely the difference between the commodity prices at separate points, reverses the regulatory trend which is based upon the competitive transportation structure acting to ensure competitive natural gas markets. This interest in the prices of the natural gas commodity presents pipelines with an incentive to withhold

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[15]See, e g., Transwestern Pipeline Co , 100 FERC ¶ 61,058 (2002), in which a shipper agreed to a negotiated transportation rate based upon a basis price differential that led to prices many times the pipeline's maximum rate.

[16]Order No. 636 at 30,393, citing. S.Rep. No. 39, 101 Cong., 1st Sess., at p. 2 (1989).

[17]In Order No. 636, the Commission determined that because of firm transportation available under the rules promulgated by Order No. 636, and because of the abundance of uncommitted gas supplies available to replace pipeline sales of gas throughout North America, it would not be profitable for a pipeline to attempt to exercise market power over the sale of natural gas. Order No. 636 at 30,440

existing capacity in order to manipulate natural gas prices and may also create a disincentive to invest in the expansion of capacity.[18]

23. While such pricing mechanisms may be useful in permitting parties to the negotiated agreement to engage in various hedging programs and gas supply cost-management programs, in the Commission's view this flexibility cannot justify the increased risk of market manipulation faced by market participants. This slight limitation of transportation pricing flexibility is offset by the fact that negotiated rates may be based upon a virtually unlimited number of non-gas indices or other financial mechanisms that have no relationship with the commodity price of gas and are therefore not subject to manipulation through the withholding of pipeline capacity.

24. Accordingly, the Commission will no longer permit the pricing of negotiated rates based upon natural gas commodity price indices. Negotiated rates based upon such indices may continue until the end of the contract period for which such rates were negotiated, but such rates will not be prospectively approved by the Commission.

Filing Requirements

25. As the Commission's negotiated rate program has evolved, the Commission has clarified the filing requirements necessary for implementing such rates. In its original Policy Statement, the Commission stated that pipelines would need to file a tariff sheet indicating that the negotiated rate for a service would be either the rate stated on its existing rate schedule or a rate mutually agreed to by the pipeline and its customer. The Commission stated that when a rate is negotiated, the pipeline would need to file a numbered tariff sheet stating the exact legal name of the customer and the negotiated rate for the service [19]

26 The Commission then modified this filing requirement to require that the pipeline file either the negotiated contract itself or a tariff sheet reflecting the essential elements of the negotiated rate agreement necessary to permit shippers that believe they are similarly situated to the shipper receiving the negotiated rate to make such a determination.[20] The

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[18] See Tennessee Gas Pipeline Co , 91 FERC ¶ 61,053 (2000), order on reh'g, 94 FERC ¶ 61,097 (2001).

[19] 74 FERC ¶ 61,076 at 61,241.

[20] NorAm Gas Transmission Co., 75 FERC ¶ 61,091 (1996), order on reh'g,
(continued..)

Commission determined that if the pipeline chose to file a tariff sheet, the tariff sheet must contain the essential details of the transaction.[21] In addition, the Commission required that the tariff sheet must include a statement affirming that the negotiated rate contract does not deviate in any material aspect from the form of service agreement in the pipeline's tariff.[22] The Commission found that this information was necessary so that the Commission could evaluate whether the transaction was unduly discriminatory.[23]

27 Subsequently, the Commission defined a material deviation as any provision of a service agreement that goes beyond the filling-in of the spaces in the form of service agreement with the appropriate information provided for in the tariff and that affects the substantive rights of the parties.[24] Therefore, if a negotiated rate agreement contains any such deviation from the form of service agreement, the pipeline must file the agreement for the Commission's review. The Commission will only accept negotiated rate agreements with such material deviations from the pipeline's form of service agreement if

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[20](.. continued)
77 FERC ¶ 61,011 at 61,037 (1996). 18 CFR § 154.1(b) (2003) provides that pipelines must file all contracts related to their services An exception to this general requirement is permitted by 18 CFR 154.1(d) (2003) which states that although any contract which "deviates in any material aspect from the form of service agreement in the tariff" must be filed, it also states that any contract that conforms to the pipeline's form of service agreement set forth in the pipeline's tariff need not be filed.

[21]The Commission stated that the tariff sheet "must state the name of the shipper, the negotiated rate, the type of service, the receipt and delivery points applicable to the service and the volume of gas to be transported." 77 FERC ¶ 61,011 at 61,037 (1996).

[22]The Commission's regulations provide that the pro forma service agreement must refer to the service to be rendered and the applicable rate schedule of the tariff; and, provide spaces for insertion of the name of the customer, effective date, expiration date, and term. Blank spaces may be provided for the insertion of receipt and delivery points, contract quantity and other specifics of each transaction as appropriate. 18 CFR § 154 110 (2003)

[23]77 FERC ¶ 61,011 at 61,037 (1996).

[24]Columbia Gas Transmission Corp., 97 FERC ¶ 61,221 at 62,002 (2001)

such deviations do not change the conditions under which service is provided and do not present a risk of undue discrimination.[25]

28. Many commenters assert that the Commission's filing requirements for negotiated rates provide sufficient information for the necessary transparency of negotiated transactions.[26] Duke Trading, WDG and NEG state that the current filing requirements permit the Commission and other interested parties to monitor the contracting activity of the pipelines for undue discrimination, and to allow market participants to undertake a full commercial analysis of each negotiated rate deal. El Paso asserts that there is no evidence to justify a change in the filing requirements, or that additional requirements are necessary for transparency. The KM Pipelines add that additional information may actually obscure the important terms of the agreement.

29 On the other hand, Calpine states that the filing requirements do not provide sufficient transparency of information for negotiated rate transactions and joins BP and EPSA in asserting that the lack of a consistent format complicates any assessment of the options available to a shipper when reviewing multiple pipeline filings and comparing the negotiated rates granted to other shippers. Mirant states that the current filing requirements are insufficient to ensure transparency and states that the Commission should not permit the pipelines to file a mere contract summary because the summaries may fail to disclose all meaningful and negotiated contract terms. NGSA joins Mirant and requests that the Commission require pipelines to file both the negotiated rate contract and a tariff sheet describing the contract. NGSA states that there is too much risk that the pipeline could omit details of a transaction that shippers see as important, and without full disclosure of the contract, the Commission and shippers have only limited ability to monitor negotiated transactions.

30 NASUCA and BP state that negotiated rate transactions lack transparency because of their bilateral nature, despite the posting and filing requirements NASUCA states that recourse shippers and regulatory agencies often lack access to essential information. BP states that, even when the contracts are filed, it is sometimes hard to determine what elements are negotiated.

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[25] Id. at 62.001-02.

[26] See Comments of Northern Natural, Peoples, MidAmerican, Alliance, The Industrials. ProLiance, El Paso, EnCana, INGAA, Vector, CAPP. Williston Basin, Dominion, Williams, and Duke Transmission

Discussion of Negotiated Rate Filing Requirements

31 The Commission's experience with negotiated rate filings has shown that the filings on occasion lack the information necessary for the Commission's Staff and the pipelines' shippers to analyze the negotiated agreement. First, even where the agreement contains no deviation from the form of service agreement, the tariff sheet summary may not describe the primary rate formula or the other essential elements of the transaction in sufficient detail Second, pipelines have sometimes failed to file a service agreement even though it contained a material deviation. Finally, and most importantly, where pipelines have filed service agreements with material deviations, the deviations have often not been clearly identified, requiring the Commission to carefully compare the negotiated rate agreement with the form of service agreement in order to determine how the two may differ. Indeed, on some occasions, parties have drafted the entire service agreement independently of the form of service agreement in the tariff. As a result, provisions may be worded differently from similar provisions in the form of service agreement, but it is not immediately apparent whether the parties intended the provisions to be substantively different These circumstances hinder the Commission's ability to assess whether the transaction is unduly discriminatory as well as the assessment of the transaction by shippers attempting to determine if they are similarly situated to the shipper in the negotiated transaction.[27]

32. The Commission will permit a pipeline filing a negotiated rate transaction that does not deviate from its pro forma service agreement to file a tariff sheet reflecting the terms of the agreement, together with a statement that the agreement conforms in all material respects with its pro forma service agreement.[28] However, pipelines are reminded that the tariff sheet summaries must fully describe the essential elements of the transaction, including the name of the shipper, the negotiated rate, the type of service, the

[27]See, e. g., Gulfstream Natural Gas System, L.L.C., 103 FERC ¶ 61,312 (2003); CenterPoint Energy Gas Transmission Co., 102 FERC ¶ 61.094 (2003) and CenterPoint Energy Gas Transmission Co., 102 FERC ¶ 61,059, order on reh'g, 103 FERC ¶ 61,228 (2003).

[28]This action merely emphasizes the Commission's current regulations which require that if the pipeline contends that its filing implements a negotiated contract that conforms to its form of service agreement in all material aspects, and therefore, it is not necessary to file the contract, such a filing will contain a statement that the pipeline's filing complies with the requirements of 18 CFR § 154 1(d) (2003). Violation of this regulation may result in the rejection of the filing or suspension of the pipeline's negotiated rate authority

receipt and delivery points applicable to the service and the volume of gas to be transported. Also, where the price term of the negotiated rate agreement is a formula, the formula should be fully set forth in the tariff sheet.[29] Pipelines are also reminded that, in order to file a tariff sheet summary, they must certify that the agreement contains no deviation from the form of service agreement that goes beyond filling in the blank spaces or that affects the substantive rights of the parties in any way. Since there would appear to be no reason for the parties to use language different from that in the form of service agreement other than to affect the substantive right of the parties, this effectively means that all language that is different from the form of service agreement should be filed with the Commission

33 In addition, in order to provide greater transparency and to assist the Commission and interested parties in analyzing negotiated rate transactions, the Commission has determined that the form of service agreement must be used as a starting point in drafting any negotiated rate contract. Therefore, the Commission will henceforward require that a pipeline filing a contract proposing material changes from its form of service agreement must clearly delineate differences between its negotiated contractual terms and that of its form of service agreement in redline and strikeout. In addition, the pipeline shall provide a detailed narrative outlining the terms of its negotiated contract, the manner in which such terms differ from its form of service agreement, the effect of such terms on the rights of the parties, and why such deviation does not present a risk of undue discrimination.

34. Information presented in such a manner, in conjunction with the tariff sheets, will permit the Commission and the parties to efficiently ascertain whether the proposed negotiated transaction entails such a risk of undue discrimination that it cannot be permitted or whether other similarly situated shippers may be able to obtain such service.

By the Commission Commissioner Brownell dissenting with a separate statement attached

Linda Mitry,
Acting Secretary

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[29] In the case of complicated formula, the pipeline may, as an alternative, simply file the agreement

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Natural Gas Pipeline Negotiated Rate
Policies and Practices

Docket Nos. PL02-6-000

(Issued July 25, 2003)

BROWNELL, Commissioner, dissenting

1 In this order, the majority prohibits on a prospective basis the use of gas basis differentials to price negotiated rate transactions. The majority bases its determinations on the theory that such mechanisms provide pipelines with an incentive to withhold capacity in an attempt to widen the gas basis differential

2. Gas basis differential pricing is a widely used tool for structuring competitive flexible transportation arrangements, demonstrating the appeal to both shippers and transporters alike. Many commenters argue that the Commission should assume that most shippers that negotiate rates are sophisticated market participants, and that gas basis differential pricing responds to the needs of shippers and consumers These commenters conclude that the risk of manipulation is low while the potential benefits to shippers and pipelines are high and, therefore, the Commission should not preclude such transactions.

3 Gas basis differential pricing does not blur the role of the pipeline as a transporter with no direct interest in the commodity price because pipelines already use the gas basis differentials to value transportation. Whether or not a pipeline uses gas basis differential pricing in its negotiated rate transactions, pipelines determine the level of the discount that is necessary to maintain throughput on their systems by reference to the gas basis differentials. The Commission itself has recognized that the implicit price for transportation represents the most any shipper purchasing delivered gas at a downstream market would pay to move gas from the lower priced market to the higher priced market. Order No. 637 at 31,271

4 The majority opinion ignores the Commission's existing regulations which prevent pipelines from withholding capacity The order cites to no evidence that pipelines have the ability to withhold capacity or, in fact, have withheld capacity to increase the gas basis differentials In Docket No PL02-4-000, the Commission Staff presented data it had collected concerning capacity release transactions over a 22 month period. The data

reflected that rates shippers received for their released transactions (above and below the recourse rate) tracked the applicable basis differentials. These finding further validates the Commission's determination in Order No 637 that the "fact that prices for transportation rise during peak periods is not evidence of the exercise of market power but may be the appropriate market response to an increase in demand for capacity" Order No. 637 at 31,281.

5 The majority opinion seems to rely on Transwestern Pipeline Co., 100 FERC ¶ 61,058 as a reason for prohibiting the use of gas basis differential pricing. In the Transwestern case, the pipeline was found to have violated its tariff by improperly giving prior notice of the capacity posting to two shippers that were awarded the capacity. Not complying with the open access tariff provisions is not a concern directed solely at negotiated rate transactions, but is a concern regardless of how the capacity is priced I would further note that capacity was not being withheld in that proceeding, but unfairly directed

6. Finally, the blanket prohibition of negotiated rate transactions that use gas basis differentials is overly prescriptive and an unnecessary intrusion in the marketplace, particularly when shippers have other choices. Most gas basis differential priced transactions are below the recourse rate. More importantly, shippers are protected because each negotiated rate transaction is noticed for comment and ultimately approved (or disapproved) by the Commission. The Commission has access to information about available pipeline capacity and daily gas basis differentials to monitor these types of transactions to determine if a pipeline is withholding capacity to increase the gas basis differential. With pipelines obligated to offer all available capacity, a viable recourse rate alternative, and our capability to monitor these transactions, the prohibition of gas basis differential pricing unnecessarily reduces flexibility and the value of the negotiated rate program.

7 For these reasons, I respectfully dissent.

Nora Mead Brownell
Commissioner

Docket No PL02-6-000

Commenters

Alliance Pipeline L.P. (Alliance)
American Gas Association (AGA)
American Public Gas Association (APGA)
BP Energy Company (BP) Calpine Energy Services, L.P. (Calpine)
Canadian Association of Petroleum Producers (CAPP)
Connecticut Department of Public Utility Control (Connecticut)
Consolidated Edison Company of New York, Inc and Orange and Rockland Utilities, Inc. (ConEd and Orange and Rockland)
Dominion Resources, Inc. (Dominion)
Duke Energy Gas Transmission Corp. (Duke Transmission)
Duke Energy Trading and Marketing, L.L.C. (Duke Trading)
Dynegy Marketing and Trade (Dynegy)
Electric Power Supply Association (EPSA)
El Paso Corporation's Pipeline Group (El Paso)
EnCana Gas Storage Inc., EnCana Marketing (USA) Inc.. and EnCana Energy Services Inc. (EnCana)
Gulf South Pipeline Company, LP (Gulf South)
Illinois Municipal Gas Agency (IMGA)
Independent Petroleum Association of America (IPAA)
Interstate Natural Gas Association of America (INGAA)
KeySpan Delivery Companies (KeySpan)
Louisville Gas and Electric Company (Louisville)
Maritimes & Northeast Pipeline, LLC (Maritimes)
Michigan Public Service Commission (Michigan PSC)
MidAmerican Energy Co. (MidAmerican)
Mirant Americas Energy Marketing, LP (Mirant)
National Association of State Utility Consumer Advocates (NASUCA)
Natural Gas Pipeline Company of America and Kinder Morgan Interstate Gas Transmission, LLC (jointly "KM Pipelines")
Natural Gas Supply Association(NGSA)
NEG Shippers (NEG)
NiSource Pipelines (NiSource)
Northern Natural Gas Company (Northern Natural)
Northwest Industrial Gas Users (NWIGU)
Oklahoma Corporation Commission (Oklahoma)

Peoples Gas Light and Coke Co.. North Shore Gas Co., and Peoples Energy
Resources Corp. (Peoples)
Process Gas Consumers Group, American Forest & Paper Association. American
Iron and Steel Institute, Georgia Industrial Group, Industrial Gas Users of Florida,
Florida Industrial Gas Users United States Gypsum Company (collectively, the
"Industrials")
ProLiance Energy, LLC (ProLiance)
Public Service Commission of the state of New York (New York)
Public Utilities Commission of California (CPUC)
Sempra Energy Trading Corp (Sempra)
TransColorado Gas Transmission Company (TransColorado)
Vector Pipeline L.P. (Vector)
The Williams Companies, Inc. (Williams)
Williston Basin Interstate Pipeline Company (Williston Basin)
Wisconsin Distributor Group (WDG)

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
UNITED CITIES GAS COMPANY,	)	
a Division of ATMOS ENERGY	)	Consolidated Docket Nos 01-00704 and
CORPORATION INCENTIVE	)	02-00850
PLAN (IPA) AUDIT	(	
	)	
UNITED CITIES GAS COMPANY,	)	
a Division of ATMOS ENERGY	)	
CORPORATION, PETITION TO	)	
AMEND THE PERFORMANCE	)	
BASED RATEMAKING	)	
MECHANISM RIDER	)	

AFFIDAVIT OF RON MCDOWELL

I, Ron McDowell, being duly sworn, depose and state as follows

1. I have personal knowledge of the facts or have obtained such knowledge from a review of the business records of Atmos Energy Corporation ("the Company") and/or related entities

2 I am currently President of Atmos Energy Services, the entity which provides gas supply services to the Company I have worked in gas supply in various positions with the Company and its predecessors since 1989 Throughout that time my duties have included the negotiation of transportation contracts and advising the Company all aspects of gas supply needs.

3 At present, the Company has six discounted transportation contracts that produce savings for Tennessee customers. All of these contracts for primary firm transportation and are priced as fixed rates which are less than the maximum FERC rate.

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EXHIBIT
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4 None of the six discounted transportation contracts utilize basis differential pricing as a pricing mechanism Unlike the basis differential pricing, which can change daily based on supply and demand, the Company's transportation discounts in Tennessee are fixed and do not change.

5 The hypothetical described in paragraph 12 and Exhibit A of the Affidavit of Dan McCormac is overly simplistic and does not reflect the realities of the Company's gas supply purchases The hypothetical ignores additional considerations the Company must take into account in making purchasing decisions, including operational, reliability, and safety concerns Purchases without a separate transportation component like the "Murfreesboro" example cited in Mr McCormac's affidavit are not generally backed by primary firm transportation and may not be available on critical days. In order to meet its service obligations, the Company follows a general practice of subscribing to primary firm transportation.

FURTHER AFFIANT SAITH NOT

Ron McDowell

Ron McDowell

STATE OF Texas

COUNTY OF Harris

Personally appeared before me, Mary Lou Watson, a Notary Public in and for said State and County, Ron McDowell, the within named affiant, with whom I am personally acquainted (or proved to me on the basis of satisfactory evidence), and who acknowledged that he executed the foregoing instrument for the purposes therein contained.

WITNESS my hand and seal at office, on this 20th day of May, 2004

MARY LOU WATSON
Notary Public, State of Texas
My Commission Expires
January 12, 2008

Mary Lou Watson
Notary Public

My Commission Expires:
1/12/2008

BAKER, DONELSON, BEARMAN
CALDWELL, & BERKOWITZ, P.C.

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served via U.S Mail, postage prepaid, upon the following this the 21 day of May, 2004:

Russell T. Perkins
Timothy C. Phillips
Shilina B. Chatterjee
Office of the Attorney General
Consumer Advocate & Protection Division
P O. Box 20207
Nashville, TN 37202

Randal L. Gilliam
Staff Counsel
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243

[signature]

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2830844-000077 05/21/2004

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	DOCKET NO. 01-00704
	)	
UNITED CITIES GAS COMPANY, a	)	
Division of ATMOS ENERGY	)	
CORPORATION INCENTIVE PLAN	)	
ACCOUNT (IPA) AUDIT	)	

AFFADAVIT OF FRANK H. CREAMER

I, Frank H. Creamer, being duly sworn, depose and say:

1. I am a management consultant specializing in business performance, and utility regulatory matters for gas and electric utilities through my own company, Barrington Associates Inc , located at 730 Walnut Road, Barrington, Illinois, 60010. I am Director of the company.

2. I received a Bachelor of Science degree as a Getty Oil Scholar in Petroleum Engineering at the University of Oklahoma in 1973. I also received a Masters of Business Administration with honors specializing in Finance, International Business Economics and Statistics from the University of Chicago in 1989.

3 I have thirty years of energy experience worldwide, with the last thirteen years focused exclusively in the natural gas and electric utility business sectors. I have directed or advised on projects to utilities involving commission mandated audits, rate-design, affiliated interests reviews, gas supply planning and procurement, privatization preparation, M&A, shared services assessments, and regulatory compliance.

4 As a consultant to the Tennessee Regulatory Authority (TRA), I directed the Gas Purchase Prudency Audit for United Cities Gas (UCG), Nashville Gas, and Chattanooga Gas in 1993-1994, prepared an analysis of UCG's 1st year experimental Performance Based Ratemaking ("PBR") program in 1995-1996; prepared an analysis of UCG's 2nd year

PENGAD-Bayonne, N.J. EXHIBIT 3

experimental PBR program in 1996-1997; in 1998, served as the TRA's witness in the remand of the 1996 Phase One proceeding wherein the TRA considered continuing the PBR mechanism, and also in 1998, served as the TRA's witness for the Phase Two proceeding to determine whether to continue the PBR mechanism beyond its second year on a permanent basis.

5 From 1995 to 2002, as an Associate Partner with Accenture in the North America Utility Business Unit, I participated in projects that included business restructuring, energy marketing, gas supply planning, regulatory strategy, rate design, operational improvements, transformation outsourcing and shared services From 1994-1995, as a Principle with Computer Science Corp (CSC), I participated in projects that included supply chain reengineering, and T&D reengineering From 1989-1995, as Principle and head of the Natural Gas Practice for Theodore Barry & Associates (now PA Consulting), I participated in nuclear retrospective prudency audits, cost-of-service audits, general management audits, gas procurement audits, business redesign projects, gas supply designs, and gas marketing development From 1981-1989, as Chief Engineer with Craddock Engineering, I was responsible for the engineering design and operations of the exploration and production activities of AGIP's (ENI) oil and gas operations. From 1978-1981, as V.P. of the Northern Trust Bank, I was responsible for the valuation of the energy-based portfolio of loans. From 1973-1978, as Senior Engineer with Amoco Production and Amoco International Oil Company, I was responsible for certain exploration and production activities in the US and Middle East

6 I am providing this affidavit on the behalf of UCG in regard to the TRA's staff compliance audit of UCG's PBR mechanism for the plan year April 1, 2000 – March 31, 2001, dated April 10, 2002. The objective of the audit was to determine whether the balance in the Incentive Plan Account (IPA) as of March 31, 2001 was calculated in conformance with the terms of the PBR mechanism and to verify that the factors utilized in the calculations were supported by appropriate source documentation. I am also providing this affidavit in response to both the CAD's Memorandum in Support of Motion for Partial Summary Judgment ("CAD's Memorandum") and which included the affidavit of Stephen N. Brown, Ph.D., both

dated July 17, 2002 and the TRA Staff's Brief in Support of the Motion for Summary Judgment ("Staff's Brief") dated July 31, 2002, which included the affidavits of Pat Murphy dated July 31, 2002 and Stephen N Brown dated July 26, 2002.

7 Specifically, I am giving my opinion on the treatment of transportation costs as one of UCG's city-gate cost components in the commodity portion of the PBR mechanism. I am also giving my opinion on the inclusion of the Nora contract and its treatment of transportation costs under the commodity portion of the PBR mechanism.

In reaching these findings, I relied on the UCG's application, final orders, testimony, Directors' Conference excerpts, UCG annual report, my report dated February 28, 1997, and notes from my March 13, 2002 meeting with TRA staff.

8. I respectfully disagree with the CAD's Memorandum's conclusion that:

> " UCG's sudden inclusion of negotiated transportation discount contracts in their IPA is a significant departure from the terms of their original IPA and violates the final order " [1]

I also respectfully disagree with the conclusion in the Staff's Brief that:

> " Neither the Phase Two Order nor United Cities' PBR Tariff provides, directly, ***or by implication***, for sharing of "savings" from discounted transportation contracts " [2] (emphasis added)

With discounted transportation costs included in the PBR as envisioned, transportation discounts qualified for distribution under the PBR plan. As I will show, the existing methodology provides the mechanism for calculation these benefits

As I will show, and as the CAD's Memorandum concludes, transportation costs were envisioned to be included in the PBR program and that to exclude them now would be a material defect in the program. [3]

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1 CAD's Memorandum in Support of Motion for Partial Summary Judgment, 7/17/02, p. 10

2 TRA Staff's Brief in Support of Motion for Summary Judgment, 7/31/02, p. 17

3 I understand that UCG has various legal arguments, which supports the content of its annual report that is the subject of the pending IPA audit My testimony does not impact those arguments and

9 With regards to the Nora contract, I find that UCG was entitled to Nora benefits under the PBR program As I will show, the intent of the PBR plan in accounting for Nora benefits and the recommended approach with regards to calculating benefits is well documented by the plan.

10 By way of background, the TRA, in approving the experimental PBR mechanism in 1995, noted that the agency should begin to look to incentive programs and more streamlined regulation to improve efficiency and hold down costs to consumers [4]. Consistent with the TRA objective, the TRA adopted a PBR program that was intended to span the entire spectrum of gas procurement, storage, and capacity activities. The CAD's Memorandum [5] and my testimony during the 1998 proceeding [6] confirms this intent, and notes that these gas cost related activities, which directly impact the ultimate price paid by the consumer, were initially captured through five separate and distinct PBR mechanisms [7], namely:

a) Gas Procurement
b) Seasonal Pricing Differential
c) Storage Gas Commodity
d) Transportation Capacity Cost
e) Storage Capacity Cost

In making the PBR plan permanent in 1999, the Authority did not revise either the intent nor the scope of the plan, but did simplify the PBR mechanism by collapsing the above five

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it is my understanding that it is offered in the alternative should the TRA not accept UCG's position thereon

4 United Cities Gas Company, Second-Year Review of Experimental Performance-Based Ratemaking Mechanism. April 1, 1995 - November 30, 1996, 2/28/97, p 7

5 CAD's Memorandum in Support of Motion for Partial Summary Judgment, 7/17/02, p 3

6 Vol 1 p 61, lines 6-9

7 Order of the Tennessee Public Service Commission dated May 12, 1995

mechanisms into two, as follows[8]:

a) Gas Commodity Cost

b) Capacity Release Sales

As the CAD's Memorandum notes [9], my testimony as the TRA witness recommended collapsing the five mechanisms into two, and concluded that the sharing formulas would not have to be changed. Therefore, I agree in part with the CAD's Memorandum that the intent of the PBR plan was clearly broad enough to account for the entire associated commodity cost of purchasing, delivering, and storing of gas to the end consumer and in doing so, accounted for the:

a) Costs of the commodity portion of gas

b) Costs of transporting the commodity to the city gate

c) Costs of gas storage

11. During the experimental PBR timeframe, UCG's actual transportation costs for moving the gas from the pipeline receipt point to UCG's city-gate was at the applicable undiscounted, published FERC Tariffed rate. These rates included both the pipeline demand and volumetric costs associated with natural gas pipeline transportation services. [10] Subsequent to the experimental PBR timeframe, UCG began extensive negotiations with pipeline companies seeking to obtain discounted transportation contracts for moving gas from the respective pipeline receipt points to UCG's city gate. The prospects of sharing the realized

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8 Final Order Phase II, TRA Docket 97-01464, 8/16/99, p 28

9 CAD's Memorandum in Support of Motion for Partial Summary Judgment, 7/17/02, p. 9

10 FERC rates were comprised of three components. 1) Tariffed Transportation Demand Rate· the applicable, undiscounted, published FERC tariffed Transportation Demand Rate (TDR) was multiplied by the Demand Quantities (DQ) contracted for by UCG from its applicable pipeline transportation provider to determine the fixed cost portion of the transportation service, 2) Tariffed Transportation Commodity Rate the applicable, undiscounted, published FERC tariffed Transportation Commodity Rate (TCR) is to be multiplied by the Actual Volumes (AV) delivered at the UCG's City Gate by its applicable transportation provider for the month to determine the variable cost portion of the transportation service, and 3) Surcharges and Direct Bills Surcharges and Direct Bills, and other applicable amounts (S&DB) approved by FERC would include surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs

transportation savings with the consumer through the PBR plan was clearly a positive incentive for UCG to actively and aggressively pursue these opportunities

12. I respectfully disagree with the CAD's Memorandum, which implied that the transportation costs of delivering the commodity to the city-gate is captured in the second PBR mechanism, Capacity Release Sales [11]. Instead, as the Staff's Brief and Pat Murphy's affidavit found, "The negotiated discount transportation contacts are distinct from United Cities' release of transportation capacity under the Capacity Release Mechanism of the PBR Tariff." [12 13]

I will demonstrate later in an example that the transportation cost of delivering the commodity to the city-gate was not intended to be captured in the Capacity Release Sales mechanism, but instead was intended to be captured in the commodity mechanism of the PBR plan. The Capacity Release Sales component of the PBR plan was comprised of the release of UCG's firm capacity on a short-term or long-term basis. Firm capacities were and are fixed assets that are made up of firm transportation capacity that the company maintained on upstream pipelines and/or storage. UCG released this capacity through marketing to 3rd parties the unused capacity and generated revenues, which were shared between the company and its ratepayers. Therefore, actual transportation costs, either discounted or not, were irrelevant to Capacity Release Sales mechanism.

13. The CAD's Memorandum and the CAD's response to UCG's data request[14] mischaracterizes my testimony in the Original Docket, and the testimony of James R. Harrington that "***all*** transportation prices were included in the indices" [15] (emphasis added). As discussed in the following, the indices in themselves represented only the transportation costs up to the pipeline receipt point and ***not*** UCG's costs of transporting the gas from the receipt point to the city-gate. Additionally, the testimony of Mr. Harrington referenced by the CAD clearly notes that the indices were chosen to capture the market prices at the ***various points of***

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11 CAD's Memorandum in Support of Motion for Partial Summary Judgment, 7/17/02, p. 9
12 TRA Staff's Brief in Support of Motion for Summary Judgment, 7/31/02, p 25, footnote 74
13 Pat Murphy's affidavit, 7/31/2002, p 3
14 CAD's Revised and Supplemental Responses to First Data Requests From United Cities Gas Company, 10/14/2002, p 2
15 *id*, p 14

purchase (emphasis added).[16] Hence, the indices do indeed serve as a proxy for the market place, but only with regards to commodity purchases at pipeline receipt points

As noted in Dr Brown's CAD affidavit [17] and as documented in the tariff [18], a basket of widely published indices was used in order to measure the commodity cost effectiveness of UCG's gas purchasing decisions:

a) Inside FERC -- First day of the month for one month or longer purchases

b) NYMEX – Monthly close price for one month or longer purchases

c) Natural Gas Intelligence - Bid week average published index price for one month or longer purchases

d) Gas Daily – First day of the transaction price for mid month or incremental purchases only

The above indices included only the upstream transportation cost to get the gas from the well head to pipeline receipt point and does not include UCG's cost of transporting the gas from the pipeline receipt point to the city-gate. For example, Inside FERC tracts first-of-the-month bidweek price reports for monthly spot gas delivered to 46 locations on 25 pipelines. Reported for each pipeline receipt point is a price range and an index price. The index price is an assessment of the price at which the majority of dealmaking occurred for the pipeline ***delivery location***. [19]

14 Dr. Brown stated in his CAD affidavit that the tariff directed UCG to compare its actual prices to an average of prices derived from all three price indices, which in turn are "accepted as representing all pipelines in the market". [20] As noted above, these price indices, in themselves, are commodity only based indices, and do not contain downstream transportation costs, i.e the transportation cost from the pipeline receipt point to the company's city gate,

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16 Prepared Direct Testimony of James R Harrington, 8/13/1997, p 23, line 3

17 CAD affidavit of Dr Stephen N. Brown, ¶ 6, p 2

18 Tariff of United Cities Gas Company, A Division of Atmos Energy Corporation, TRA No 1, 1st Revised Sheet No 45 1, Canceling Original Sheet No 45 1, Issued by Thomas R Blose, JR , President, Dated issued March 16, 1999, Effective Date April 1, 1999 at Original Sheet No 45 6, p. 1

19 McGraw-Hill's U S. Natural Gas Methodology

20 CAD affidavit of Dr Stephen N. Brown, ¶ 6, p 2

without the appropriate transportation cost adjustors [21] Consequently, I respectfully disagree with Dr. Brown's conclusion and find that the actual prices paid by UCG for both commodity and transportation cannot and should not be compared to the average of prices derived from all three price indices, in absence of the application of the transportation cost adjustments.

15. Dr. Brown concluded that UCG's comparison of actual transportation cost to a single pipeline's maximum price of transport does not allow comparison to actual transportation prices achieved throughout the entire market [22] I respectfully disagree with Dr. Brown's conclusion that the maximum FERC rate cannot serve as indicator of prices achieved in the market [23] For instance:

a) UCG negotiates discounts off of FERC approved rates, not off commodity-based indices

b) The approved, maximum FERC rate has been accepted elsewhere in the industry as true market indicator of a long-term, firm transportation costs [24]

c) The maximum FERC rate would serve as the benchmark for any PGA audit or prudence review If, for example, the downstream, firm transportation costs were excluded in the PBR, the TRA would be required to establish the basis for comparing actual firm transportation costs to a standard of prudence, e g approved, maximum FERC rates

d) A review of all of the transportation contracts negotiated by UCG reveals that the majority of contracts were priced at the maximum approved FERC rate

e) The approved Nora arrangement, per the existing PBR plan, relied on the maximum FERC rate in calculating the transportation cost adjustor to the commodity market indexes

16 The intent of any PBR program is to incent the company to aggressively pursue and exploit any and all cost saving opportunities and by doing so, share the benefits (or losses) with the consumers under an equitable sharing formula based on actual performance. Transportation discounts, as a feature of the marketplace, is an example of cost saving

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21 Transportation cost adjustors

22 *id*

23 CAD affidavit of Dr Stephen N Brown, ¶ 6, p 3

24 PBR plans for LG&E, and Western Kentucky Gas

opportunities. The discounts must be aggressively pursued, and are not routinely available just for the asking. For example, Atmos as a whole holds transportation contracts with 28 interstate pipelines, but has only two pipelines which offer discounts on all of their contracts. Ten of the pipelines have agreed to discounts on some, but not all of the contracts. Therefore, Atmos has, in fact, been unsuccessful in obtaining discounts from the majority of the available pipelines Similarly, UCG's Tennessee service territory is served by six pipelines, none of which have discounts on ***all*** of UCG's contracts Only three pipelines serving UCG's territory have some contracts that are discounted. Therefore, half of UCG's pipelines serving UCG's territory have no discounted contracts[25]. Additionally, UCG held a total of 16 contracts on the six pipelines servicing its Tennessee territory, of which 11 contracts were undiscounted and priced at the maximum FERC rate.[26] This magnitude of undiscounted contracts demonstrates that discounts were not routinely and easily granted, and required UCG to actively seek and negotiate discounts. Furthermore, the maximum FERC rate is the market indicator for transportation costs during the applicable time period.

17. The best measure of UCG's success in seeking lower cost, firm transportation arrangements that would impact the ultimate total cost of gas to the ratepayer would be its ability in.

a) Obtaining discounts off of FERC maximum approved price;

b) Ability to sustain these discounts upon renewal or renegotiation;

c) Maximize the discount off the approved price that UCG receives from its pipeline transportation provider for the specific and unique pipeline transportation paths, e.g. receipt point to city gate.

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25 East Tennessee, Columbia Gulf, and Tennessee Gas have some discounted contracts; Texas Gas, Southern Natural, and Texas Eastern have no discounted contracts

26 UCG held two contracts on Tennessee Gas. One of these contracts was a partially discounted contract This partially discounted contract provided a transportation rate that moves the commodity from Zone 0-1 at the maximum FERC rate, whereas the transportation rate that then moves the gas through Zone 1-1 to UCG's city gate is at a discount off maximum FERC rate The other Tennessee Gas contract is priced at the maximum FERC rate UCG also holds three contracts on Columbia Gulf, only one of which is discounted UCG also holds four contracts on East Tennessee, three of which are partially or fully discounted

18 I respectfully disagree with Dr. Brown's conclusion in his CAD affidavit that transportation costs vary widely and therefore, the maximum price is not a market index or a benchmark [27] Each pipeline seeks and receives an approved FERC rate, the maximum the pipeline transportation provider is allowed to charge. These maximum-approved rates are for firm, long-term transportation arrangements, not for short-term, interruptible service. As noted above, following the experimental PBR plan period, discounted firm transportation contracts began to be a feature of the marketplace and accordingly, have been aggressively pursued by UCG. As noted above, UCG currently holds ***some*** discounted firm transportation contracts on ½ of its pipelines serving the Tennessee territory, which are a result of successfully negotiating discounts off the maximum approved FERC rates. The remaining ½ of UCG's pipelines provide no discounted firm transportation contracts and are priced at the FERC approved transportation rate. Therefore, the benchmark was indeed the FERC approved transportation rates, which were the market-clearing price for the majority of the firm transportation contracts and the basis for the negotiations for any discounts. The approved FERC rate is unique to a pipeline, and to a pipeline's receipt point and delivery point. These prices do not in fact vary widely, but instead are specific to the contract type (e g delivery/receipt points, volumes, seasonality, and duration). Therefore, the approved FERC transportation rates serve as the most objective benchmark for the transportation component of total gas costs

19. A published index for transportation costs does not currently exist. Although FERC, in 1996, required pipelines to file Discount Transportation Reports, which provided particular information regarding discounted rates, either firm or interruptible, the report is not a reliable source of information regarding firm transportation arrangements. My review of the reports indicated that certain transportation transactions that were reported were found to be capacity release, even though a pipeline was not required to file this information if the discount was related to the release of capacity. Nonetheless, the reported discounted transportation arrangements were not differentiated between firm, forward haul, backhaul, interruptible and/or winter only service Consequently, prices would have been found to vary widely when making

[27] CAD affidavit of Dr Stephen N Brown, ¶ 6, p 3

an apples-to-oranges comparison between firm, interruptible, and capacity release arrangements.

20. As noted in my report [28], the above referenced indices were used in order to measure the commodity cost effectiveness of UCG's gas purchasing decisions (e.g. Inside FERC, NYMEX, Natural Gas Intelligence, and Gas Daily) These indices would be adjusted depending on whether the purchases were long-term and if so, if they were upstream or ***at the city-gate*** (emphasis added). The two adjustments were:

a) Competitive Bid Adjustment for long-term upstream (spot or swing) purchases, using the three-year rolling average of long-term contract premium over spot

b) Avoided Cost Adjustment for long-term city-gate (spot or swing) purchases, using the ***appropriate pipeline transportation cost*** (emphasis added).

The table below summarizes the formulas for each of the procurement-related transaction possibilities.

Category	**Monthly**	**Long-term Upstream**	**Long-term @ City Gate**
Spot Gas Purchases	Average of the three market indexes (FERC, NYMEX, NGI)	Average of the three market indexes + Competitive Bid Adjustment	Average of the three market indexes + Competitive Bid Adjustment + Avoided Cost Adjustment
Swing Purchases	Gas Daily Index	Gas Daily Index + Competitive Bid Adjustment	Gas Daily Index + Competitive Bid Adjustment + Avoided Cost Adjustment

Using the above table, each purchasing decision was mapped to the appropriate category in order to determine the relevant index and ***adjustors for transportation costs***. During the experimental period, if gas purchases were less than 98% of the benchmarks, savings were

[28] United Cities Gas Company, Second-Year Review of Experimental Performance-Based Ratemaking Mechanism April 1, 1995 - November 30, 1996, 2/28/97, p 8

earned and shared equally by the ratepayer and the company. If purchases exceeded 102% of the benchmarks, penalties were calculated and also shared equally between the ratepayer and the company. When gas purchases fell between 98% - 102%, no gains or penalties were calculated Following the experimental period, the PBR plan was made permanent in 1999 with the changes, among others, in the deadband to 97 7% - 102% [29]. Furthermore, at the end of each three-year period beginning in 2002, the deadband will be readjusted to 1% below the most recent annual audited results of the incentive plan. Consequently, the commodity mechanism was intended to include a transportation cost component through the above referenced transportation cost adjustor.

21. An example of the use of how the transportation costs are used in calculating gains or losses was the Nora arrangement, which supplied gas to UCG's Tennessee and Virginia service territory and dealt with special purchases at UCG's distribution system. Purchases made under the Nora contract avoid or reduces transportation costs on UCG's pipelines This transportation cost savings was calculated based on the approved FERC maximum rate for the purposes of calculating the benchmarked cost It was labeled as Avoided Costs and is a key element of the benchmark formula. The approved FERC maximum rate included both the pipeline demand and volumetric costs as follows:

a) Tariffed Transportation Demand Rate

b) Tariffed Transportation Commodity Rate

c) Surcharges and Direct Bills

Although the Nora contract was initially excluded from the permanent PBR program, the Authority, on November 8, 2001, entered an order granting permission to include the newly renegotiated NORA contract in the PBR [30]. The Authority held:

> Upon a careful review of the petition, and of the entire record in this matter, the Authority approved United Cities' request to include transactions under the new NORA contract in its Incentive Plan.

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29 Final Order Phase II, TRA Docket 97-01464, 8/16/99, p 22

30 Order, Docket No 00-00844

The Nora contract is a long-term contract. The Avoided Costs are added to the average of the three indexes (FERC, NGI, and NYMEX) to arrive at an "Average Index" price. This Average Index price is a bundled index with both commodity and transportation components. Gains/penalties are then calculated if the invoiced price is 97 7% or less than the Average Index price (Gains) or 102% or more than the Average Index price (Penalties).

The table below demonstrates these calculations.

Category	Index ($/MMBTU)	Cost ($/MMBTU)	Gains/losses ($/MMBTU)
Supplier Invoice Price (commodity)[31]		N/A	
Pipeline Invoice Price (transportation)[32]		N/A	
Total Bundled Invoice Price (commodity and transportation)		$6 3050	
Average of Commodity Only Indexes	$6.1893		
Plus Transportation Cost Adjuster from the Benchmark FERC Approved Max. Demand Rate	$0.3522		
Bundled Index (commodity and transportation)	$6.5415		
97.7% of Bundled Index (Gains)		$6 3910	$0 086
102% of Bundled Index (Losses)		$6.6723	

Note: Above values are hypothetical but are representative of actuals during the audit year.

The above methodology correctly outlines the manner in which the PBR plan envisioned the

31 Invoiced volumes -- MMBTU
32 Demand rate based on MDQ, not actual throughput

treatment of the Nora benefits, and notes that:

d) The Nora arrangement compares the total bundled cost at the city gate, e.g. commodity and transportation, to a market index that includes both commodity and transportation costs

e) The FERC maximum approved rate is used as the benchmark to adjust the commodity indices and therefore, bundle both the commodity and transportation cost into a single market index

f) Benefits are calculated subject to the 97.7% - 102% deadband

22. By analogy, the city gate cost of other, non-Nora gas purchases would include both a commodity and transportation cost component. Therefore, UCG's actual transportation cost to deliver the gas from the pipeline receipt point to UCG's city gate would be bundled with the relevant commodity purchase to determine the actual city gate cost. As with Nora, this bundled, city gate cost would be compared to the market index, which includes a both commodity and transportation benchmark component. Also as with Nora, gains available to UCG would only occur if UCG's actual costs were better than 97 7% of the benchmark. Losses would occur if UCG's actual costs were more than 102% of the benchmark Benefits or losses would be shared between UCG's customers and UCG on a 50% / 50% basis and subject to the earnings cap.

The following table demonstrates the above for a specific supplier and transportation delivery path:

Category	Index (\$/MMBTU)	Cost (\$/MMBTU)	Gains/losses (\$/MMBTU)
Supplier Invoice Price (commodity) [33]		$6.0928	
Pipeline Invoice Price (transportation) [34]		$0.2339	
Total Bundled Invoice Price (commodity and transportation)		$6.3267	
Average of Commodity Only Indexes	$6.1893		
Plus Transportation Cost Adjuster from the Benchmark FERC Approved Max. Demand Rate	$0.2355		
Bundled Index (commodity and transportation)	$6.3545		
97 7% of Bundled Index (Gains)		$6 2083	$0
102% of Bundled Index (Losses)		$6 4815	$0

Note. Above values are hypothetical but are representative of actuals during the audit year.

As demonstrated in the above table, and again, similar to Nora, the bundled cost of commodity with its associated transportation cost is compared to single index, which includes a commodity and transportation component The transportation component of the index relies on the approved FERC rate for the various unique pipeline delivery paths for the commodity.

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33 Invoiced volumes -- MMBTU

34 Since none of UCG's pipelines offer discounts on all their transport contracts, the Pipeline Invoice Price would reflect, therefore, both discounted and undiscounted transportation arrangements for each of the unique transporting delivery paths for the commodity Assume that no commodity transportation charges or fuel charges, for illustrative purposes Demand rate based on MDQ, and divided by 30 4 days/month to yield the rate associated with the delivery of the commodity

Also of note in the above example, although both the commodity portion and the transportation portion of the city-gate cost were below the Bundled Index, the benefits, in this example, would accrue 100% to the consumer due to the deadband calculation

23. The previous section demonstrates, in concept, how the calculation of benefits would be performed. The calculation would rely on determining the specific transportation costs, both discounted and undiscounted, for a unique delivery path and in some instances, multiple delivery paths for a particular commodity. A FERC published rate for each delivery path would be determined and then applied as the transportation component in the bundled market index However, rather than track both discounted and undiscounted transportation costs associated with each gas commodity purchase and map these purchases to a unique, and sometimes multiple delivery paths, a simpler reporting and tracking format is recommended, as follows

a) Calculate the total actual monthly transportation cost paid by UCG under each of its discounted and undiscounted transporting pipeline contracts for the state of Tennessee[35]

b) Allocate the total actual monthly transportation costs to each of UCG's supplier commodity purchases in order to calculate a total bundled price for that purchased commodity The resulting total price for that commodity purchase would then reflect both commodity and transportation costs[36]

c) Determine the Transportation Cost Adjuster utilizing the FERC Approved maximum transportation rates, both fixed and variable[37]. As in Nora, add

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[35] Sum the actual invoiced transportation costs, both fixed and variable, for each of UCG's transporting pipeline contracts, associated with delivery of the commodity from the pipeline receipt point to UCG's delivery point(s) in the state of Tennessee

[36] Divide UCG's total transportation costs for the state of Tennessee be by the total commodity supplier purchases for the month in order to determine a transportation cost per MMBTU allocation factor Each of the supplier's commodity purchases would be multiplied by the transportation allocation factor to determine the actual transportation cost allocated to that specific supplier's commodity purchase and therefore, reflect the allocated transportation cost to move the commodity from the pipeline receipt point to UCG's city gate

[37] As in Nora, for each transporting pipeline contract, use the maximum FERC rate to determine the benchmark cost for the transportation component of the market index Undiscounted contracts would, of course, have the same actual transportation costs as the benchmark for that contract The discounted contracts would show some amount of avoided transportation costs As in Nora, these benchmark transportation costs, based of maximum FERC rates, include both the pipeline demand and volumetric

this Transportation Cost Adjuster to the Commodity Index so as to determine a bundled market index, that includes both commodity and transportation components, against which performance would be determined

d) Calculate the average of the three Commodity only indexes, in the same manner used for all commodity purchases as laid out in the PBR plan

e) Add the Transportation Cost Adjuster calculated in step c) above to the Commodity only index from step d) above in order to determine the bundled index, as in Nora. This Market index serves as the standard of performance against which UCG's commodity purchases, and the transportation costs of delivering that commodity to UCG's city gate would be compared

f) Compare actual bundled costs (both commodity and transportation) against the Market index to determine gains/losses. Apply the deadband to determine the amount of gains /losses that would be shared between the ratepayer and UCG under the 50/50 sharing formula.

The following table illustrates the above methodology for a single month and for a single

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costs and would be based on the Tariffed Transportation Demand Rate, Tariffed Transportation Commodity Rate and Surcharges and Direct Bills supplier commodity purchase contract:

Category	Cost ($)	Volumes (MMBTU)	Index ($/MMBTU)	Cost ($/MMBTU)	Gains/losses ($/MMBTU)
Supplier Invoice Contract Price (commodity) [38]	$1,696,509	387,393		$4.3793	
Total Purchased Volumes[39]		1,270,798			
Actual Pipeline Invoice Cost (transportation) for entire state of Tenn.[40]	$1,957,357				
Actual Transportation Cost Allocation Factor [41]				$1.5403	
Totaled Bundled Actual Cost[42]				$5.9196	
Benchmark FERC Approved Max Rate (all transportation contracts)	$2,199,570				
Transportation Cost Adjuster			$1 7309		
Average of Commodity Only Indexes			$4 4670		
Bundled Index (commodity and transportation)			$6 1979		
97.7% of Bundled Index (Gains)				$6.0553	$0.1357
102% of Bundled Index (Losses)				$6.3219	

38 Invoiced volumes -- MMBTU

39 Excluding Nora, so as to not double count

40 Invoiced actual costs

41 Actual, total transportation costs for Tenn divided by the purchased volumes for Tenn.

42 Sum of actual commodity cost and allocated actual transportation cost

Note: Above values are representative of actuals for a single month for a single supplier during the audit year A similar calculation, using the above methodology for the remaining supplier contracts would be conducted, as well for the remaining months of the plan year.

24. In summary, the cost to deliver the gas from the pipeline receipt point to the city-gate can be captured by the PBR mechanism:

a) The total bundled cost at the city gate, e g commodity and transportation, is compared to a market index that includes both commodity and transportation costs

b) FERC approved rate is used as the benchmark to adjust the commodity indices and therefore, bundle both the commodity and transportation cost into a single market index

c) The 97 7% - 102% bandwidth is applied to calculate gains and losses. Benefits are shared 50/50 between the ratepayer and UCG

25. To now exclude transportation costs, as a component of the PBR program would be a material defect in the plan A fundamental requirement of any PBR program is to incent proper business decisions and not reward the company at the ratepayer's expense. In order to satisfy this design principle, the PBR program must include transportation costs in order to satisfy the intent of the TRA. For example, if transportation costs were excluded from any PBR performance calculations, a utility could pass on to the ratepayer relative high transportation costs arrangements that were obtained in order to secure relatively lower commodity costs and thereby earn benefits under a PBR formula that relied on pure commodity costs alone This clearly was not the intent of the PBR program as envisioned by the TRA in their final order.

26. In summary, I believe the intent of the PBR plan was to be all-inclusive of any and all associated costs of gas to the ratepayer, and include without limitation transportation expenses. Therefore, the discounted and avoided transportation costs from the pipeline receipt point to UCG's city-gate would:

a) Not require a modification of the formula

b) Be captured in the Gas Commodity Cost component of PBR plan

c) Be bundled with actual commodity purchase costs and compared to the bundled market index, as in the Nora arrangement

d) Rely on the maximum approved FERC rate for the transportation component benchmark in the bundled market index, as in the Nora arrangement

e) Be subject to the 97.7% -102% benefits sharing formula and the $1.25 million earnings cap.

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Dated: 10/19/02

Sworn and subscribed before
me this 19th day of October, 2002

NOTARY PUBLIC

My commission expires: 5/30/04

"OFFICIAL SEAL"
JESSICA A. ROEDL-BAUER
Notary Public, State of Illinois
My Commission Exp. 05/30/2004

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served via facsimile and/or hand delivery on October 21, 2002.

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