asset management business, at the time they were perceived to be fairly strong, well-positioned companies. Similarly, while Mirant's credit rating at the time was lower than the others, the significance of the problems facing it in particular and the industry in general were not widely known. Further, while Enron was only a day away from bankruptcy when the Mirant contract was signed, the issues facing it were thought to be Enron-specific.

12. CG&E's actions in transferring the contract from Mirant to CM&T appear to have been reasonable given the conditions that existed at the time.

Given the dire plight of the industry and the recently acquired knowledge as to how utility assets might be vulnerable in a bankruptcy situation, it was appropriate for CG&E to act quickly and decisively. A legal analysis of the situation and the consequences of a Mirant bankruptcy conducted for CG&E during that time period indicated that in the event of such bankruptcy, CG&E could not use the gas in storage[6] as it would become part of the bankruptcy estate. The company would then be required to purchase other gas at market prices and to pursue claims against Mirant's bankruptcy estate or under the Letter of Credit which was part of the initial agreement. This analysis is consistent with the analysis Liberty has seen in other situations of this type.

Thus, while it is preferable to have a well-constructed RFP, a broad field of bidders and a structured evaluation process, particularly when an affiliate is involved, Liberty recognizes that the urgency of the situation did not permit such a process to take place. And, even as that process was taking place, the situation was very fluid. Other gas management firms were retrenching as well, and the realistic choices were to take the functions back internally or to transfer them to the one firm that was willing to take it on (at a reduced payment level but still making a contribution), with some comfort that at the highest levels of Cinergy there was an awareness that CM&T was financially sound.

13. The RFx System appears to be a useful and efficient tool for conducting a bidding process, and its continued use for asset management services, and extension to commodity purchases, appears to be justified.

Used properly, the RFx System is an unbiased tool that is more efficient with respect to both timeliness and effort. It ensures that the same information is made available to all prospective bidders at the same time and eliminates the dependence upon telephone calls, faxes, and e-mails. It also time and date stamps all contacts with the system, providing a precise audit trail, and it has the potential for generating various reports and documentation quickly and easily.

14. The process and procedures governing selection of an Asset Manager, and the accompanying use of the RFx System need to be better documented and refined. *(Recommendation #4)*

One of the claimed benefits of the RFx System is the level of documentation and ease of regulatory review. However, the documents generated by the system in this particular

[6] Estimated to be some $61 million at the time, based upon the value of the gas remaining in storage.

application were incomplete and not user friendly. Further, the system does not eliminate the need for CG&E evaluation and review.

In the most recent selection of the Asset Manager, no summary evaluation of the bids was prepared, a practice that had been followed earlier, and that was called for by the RFx System documentation. According to CG&E, the bids were identical except for the monthly payments. CG&E stated that a summary document was not prepared since the Vice President of Gas Operations was involved in the day-to-day process.

The use of the system should not be a reason to eliminate management reporting and documentation of analysis and decision-making documents. The company indicated it has not had written procedures for procuring asset management services; this would be the appropriate time to remedy that condition.

15. The process for monitoring FERC proceedings could be better defined.

The company has several different groups following FERC activities, there may be gaps in the process, and the respective roles of in-house counsel, outside counsel, and Gas Commercial Operations staff is not altogether clear. This may be more of an issue with the recent hiring of additional attorneys to address FERC matters.

16. FERC-ordered pipeline refunds are credited to customers in a timely manner.

Refund checks are received in Gas Commercial Operations and forwarded to Accounts Receivable. Checks from pipeline companies credited to Account 253.120 – Liability to Customers. After being booked into that account, refund checks are applied to the GCR Refund and Reconciliation Adjustment.[7] An experienced Rate Specialist reviews the account reconciliations and rolls them into the Reconciliation, tracking the flow through the billing system.

During the Audit Period, CG&E refunded approximately $3.4 million to GCR customers, representing 15 individual refund items from Tennessee Gas Pipeline, Columbia Gas Transmission, Columbia Gulf Transmission, and Texas Gas Transmission. Refund amounts from the pipelines varied from $2.4 million to $177. Major refunds are credited to customers during the next quarterly[8] GCR period; minor refunds are sometimes held and credited with the next major refund.

[7] The GCR has four components, Expected Gas Cost, the Actual Adjustment, the Balance Adjustment, and the Refund and Reconciliation Adjustment.

[8] The GCR has typically been adjusted quarterly, although toward the end of the Audit Period, the company received PUCO approval to adjust it monthly due to the wide swings in gas commodity prices.

17. There is no formal process for tracking the timing and amount of pipeline refunds. (*Recommendation #5*)

While a Rate Specialist follows FERC cases to some extent, CG&E does not have anyone specifically assigned to track proceedings which may result in refunds, to review FERC decisions, and to anticipate the timing and amount of refunds to be received. Thus, while they often know when a check is due, GCO staff acknowledged that sometimes a refund check hits them by surprise. CG&E does not perform its own calculations of refund amounts due to it, but rather, relies on FERC to ensure compliance with its orders.

D. Recommendations

1. CG&E should develop a set of written procedures for the gas commodity procurement function. (*Conclusion #2*)

CG&E should develop a set of formal and written procedures that describe the actual gas procurement process. Such procedures are especially important to support ongoing training programs and to provide for essential continuity of operations when staff changes are made. Included in these procedures should be an identification of the range of options to be considered in gas procurement decision-making, as well as identification of important decision points in the process.

The initial deployment of the RFx System for this application is a logical time to develop and implement such procedures. As part of those procedures, the company should develop a more refined and explicit comparison matrix to assist in the selection of winning bidders.

2. In conjunction with the development of written procedures for its hedging program, CG&E should resolve the issue related to locking in suppliers prior to the RFP process. (*Conclusion #3*)

CG&E's hedging procedures, dated August 2, 2002, were developed for UHL&P in conjunction with the filing of that company's hedging plan with the Kentucky Commission. CG&E indicated that it generally follows the same policy and procedures, noting that the same group is responsible for hedging at both companies. Subsequently, during the course of this Audit, CG&E developed a hedging policy dated April 27, 2004 which is substantively equivalent to the UHL&P policy. Liberty notes that while these documents are entitled "Policies and Procedures," they are in reality broad overview documents which do not give specific guidance as to how to implement a hedging program.

CG&E should modify its policy so that its hedging program does not lock it in to suppliers who might not otherwise be selected through the RFP process. (This recommendation should be reviewed in connection with Recommendation IV.1, which addresses the use of financial hedges.) The process as utilized now may also impose unnecessary constraints on the Asset Manager.

3. CG&E should assign the dispatch of the propane plants to the Asset Manager. (*Conclusion #9*)

Use of CG&E's assets could be better optimized if dispatch of the propane plants were to be assigned to the Asset Manager. Included in the plan to make this assignment to the Asset Manager should be an analysis that reviews the optimization potential for propane pipeline deliveries. Such an analysis should include specification of the minimum levels of propane to be maintained for peaking purposes, and should recognize any operational constraints on the system, such as potential effects on certain industrial loads.

4. CG&E should develop a set of written procedures for the procurement of asset management services, including description of how the RFx System is to be used in support of all procurement activities within Gas Commercial Operations. (*Conclusion #14*)

The procedures for procurement of asset management services should include a timeline, guidelines for selection of prospective bidders, evaluation criteria, and assignment of responsibility for both analysis and approval. In addition, since the RFx System will be used for other purposes within Cinergy, CG&E should also develop a separate set of procedures describing how the RFx System is to be used in support of all procurement activities within Gas Commercial Operations.

5. CG&E should develop procedures for monitoring FERC cases and activities, including the tracking of pipeline refunds. (*Conclusion #17*)

CG&E should develop procedures for monitoring FERC cases and activities that should include specific roles for in-house counsel, outside counsel, and GCO staff, and a flow chart for handling matters in which CG&E decides to participate. There should be a specific assignment to track pipeline case involving potential refunds, including estimating the amount of the refund due and approximate due date, as determined from FERC orders. While compliance with its orders is the responsibility of FERC in the first instance, CG&E should be doing some level of follow-up to protect the interests of its ratepayers.

Appendix 1
Summary of Pipeline and Storage Contracts

ANR Pipeline Company FTS-1 Service Agreement 11/1/01 – 3/31/02, with no rollover provisions.

Columbia Gas Transmission SST Service Agreement 11/1/93 – 10/31/04 and year to year roll-over unless notice provided 6 months prior to anniversary date.

Columbia Gas Transmission FSS Service Agreement 11/1/93 – 10/31/04, with annual roll-over unless notice provided by either party 6 months prior to anniversary date.

Columbia Gas Transmission ITS Service Agreement 5/1/02 continuing month to month unless notice given by either party 30 days in advance of monthly anniversary date.

Columbia Gas Transmission ITS Service Agreement 11/1/93 continuing month to month unless notice given by either party 30 days in advance of monthly anniversary date.

Columbia Gas Transmission ITS1 Service Agreement 11/1/93 continuing month to month unless notice given by either party 30 days in advance of monthly anniversary date.

Columbia Gas Transmission ITS2 Service Agreement 11/1/93 continuing month to month unless notice given by either party 30 days in advance of monthly anniversary date.

Columbia Gulf Transmission FTS-1 Service Agreement 11/1/94 – 10/31/04, with annual roll-over unless notice given by either party 6 months prior to anniversary date.

Columbia Gulf Transmission FTS2 Service Agreement 1/1/96 – 10/31/04, with annual roll-over unless notice given by either party 6 months prior to anniversary date.

KO Transmission Company 001: 6/1/96 – 6/1/06 with no apparent roll-over provisions.

KO Transmission Company 002: 6/1/96 – 6/1/06 with no apparent roll-over provisions.

Texas Gas Transportation Agreement 6/1/94 – 10/31/04; automatic roll-over for 5 years and subsequent 5 year periods unless CGF&E gave one year advance written notice.

Texas Gas Firm No Notice Agreement 11/1/93 – 10/31/00, automatic roll-over for 5 years and subsequent 5 year periods unless CG&E gave one year advance written notice.

Texas Gas Transmission Company Agreement dated November 1, 1993.

Texas Gas Transmission Gas Transportation Agreement 11/1/02 – 10/31/04 with automatic roll-over for one year and subsequent years unless one year notice is given.

Texas Gas Transmission Interruptible Storage Service Agreement 10/11/97 – 3/31/98 with automatic annual roll-over unless 30 days notice is given by either party.

Tennessee Gas Pipeline FT Agreement 11/1/02- 3/31/04 with a one-time reduction right at 11/1/03, requiring notification by 8/1/03, and no apparent roll-over.

IV. Commodity Pricing and Price Risk Management

A. Scope

This chapter of Liberty's report addresses the following topics in CG&E's gas commodity supply area:

- Pricing of Gas Commodity
- Hedging in the Natural Gas Business
- CG&E's Hedging Policy
- CG&E's Hedging Program

B. Background

1. Pricing of Gas Commodity

Development of Index Pricing

After the deregulation of gas prices and FERC's move toward open access on pipelines, index pricing became the standard pricing model for gas contracts. They are perceived to represent market-clearing prices. "Indexed" prices for natural gas are prices that are reported as representative of prices paid in transactions between arms-length buyers and sellers at stated locations. The locations tend to be geographic areas served by a particular gas pipeline. "Texas Gas Transmission, Onshore Louisiana" is an example of a production-area index; "Transco Zone 6" (which represents the area around New York City) is an example of a market-area index. Indexes are developed and published by industry publications, including *Inside FERC, Gas Market Report, Gas Daily* and *Natural Gas Intelligence.* Each publication has its own method for developing its indexes, most of which are done on the basis of proprietary surveys.

Each publication develops an index for each area in which gas sales transactions take place. Thus, each publication develops price indexes for as many as 100 locations. Indexes are developed for daily transactions and for monthly transactions. *Gas Daily* also publishes a weekly weighted average of daily prices for each of its pricing locations.

Gas prices are also determined through transactions on public exchanges. The New York Mercantile Exchange (NYMEX) trades a standard contract for delivery of a fixed quantity of gas (10,000 MMBtu[1] per day for one month) to a specific location in Louisiana, the Henry Hub. Those contracts trade on the NYMEX until two business days prior to the beginning of the delivery month. When the contract closes, i.e., at the close of trading on the second day prior to the beginning of the delivery month, the price of the gas to be delivered under those contracts is fixed for the volume to be delivered under each contract. Typically, these prices are referred to as "exchange-determined prices". Similarly, the Kansas City Board of Trade trades a contract for delivery 10,000 MMBtu to a location in West Texas (Waha).

[1] An MMBtu is equal to one dekatherm, which is approximately equal to one mcf.

Indexed prices and exchange-determined prices are both used in gas-purchase contracting. While there are no formal linkages between the two types of prices, they have rarely gotten out of line with each other (after adjustment for location, or "basis" differentials), as gas markets have been sufficiently liquid to allow purchases and sales in response to unusual price differentials. The financial difficulties currently being experienced by energy marketers have impacted liquidity and basis differentials somewhat by reducing market liquidity, but the relatively short duration of gas-purchase contracts (generally for one year or less) does not allow the prices to diverge very far.

Indexed prices and exchange-determined prices are both considered "market" prices. While the two types of prices are determined in different ways, the depth and liquidity of U. S. and Canadian gas markets result in prices that are determined through competitive offers in almost any location in the U. S. or Canada. Basically, pricing a gas contract at "index" means that the contract price is equal to the index price at a specified time, e.g., first of the month.

Most regulatory agencies contributed to the move toward index pricing by ordering or otherwise encouraging utilities to contract for gas at market-clearing prices. Because of the high level of price volatility (which has continued to increase over time), some utilities and other large customers locked into long term, fixed price contracts when prices were high and supply was believed to be scarce. When prices came down, the contract price did not. Conversely, when supply was abundant and prices were low, there was no pressure to sign long-term contracts, so the effect was one-sided. Thus, contracting for specified quantities of gas at market-clearing prices provided protection of supply and proved to offer significant savings to consumers over the older long-term, fixed-price model.

2. Hedging in the Natural Gas Business

While hedging contracts have been around for some time, energy hedge contracts are of fairly recent origin. Until the energy crises of the 1970's, oil and natural gas prices were regulated and very stable; consequently, there was little interest in developing hedge instruments. After oil producers and refiners experienced huge price swings during the 1970's, the crude oil futures contract was developed and began trading in 1980. In a similar fashion, the NYMEX (New York Mercantile Exchange) gas contract, which began trading in 1990, was a direct outgrowth of the gas price deregulation beginning in the 1980's. Futures contracts in general and natural gas futures are financial instruments, and can be traded for market gain or loss like other commodities, or like shares in the stock market, for that matter.

The need to develop and sustain hedging programs normally arises when the price volatility of key raw material costs which are a significant component of the cost structure, or product sales prices regularly limit the firm's ability to recapture those charges in the marketplace. In addition, that price volatility must be perceived as a continuing state of affairs; it makes little sense to organize a hedging program for a price spike caused by a temporary raw material shortage.

An industrial firm may protect a position in the physical market if they use natural gas as a feedstock for an industrial process. The hedging strategy and particular financial instruments selected can be determined through sophisticated models, with the firm's goal of achieving a relatively stable price for its industrial input. The cost of hedging will, in the long term, be a net cost to their organizations (if only because of broker fees), but their trading economics are but a part of their larger raw material or product sales economics.

While in most jurisdictions, utilities have not been permitted to earn a profit on the gas commodity, they have been permitted to pass through the prices of gas to customers through mechanisms such as the GCR. Such mechanisms allow the price of gas to fluctuate and those costs passed through to consumers on a more timely basis outside the framework of a formal rate case process.

With the increasing volatility in gas prices, regulators and LDCs have been exploring opportunities to mitigate the effects on customers of wide price swings. Three times in the last 10 years, gas prices have spiked sufficiently to send unexpectedly high gas costs through to consumers. Recent experience with high gas prices was in 2000/2001, which led to high numbers of shut-offs of gas service, and increases in LDC uncollectible expense.

Historically, use of storage provided a level of price moderation and dampening of volatility of the portfolio because gas was injected at low summer prices and withdrawn during the winter heating season. The low summer price was then blended with the higher winter prices and provided a moderating effect on customer bills. Reliance upon storage gas as a price hedge still offers some benefits, but the impact of gas-fired generation on summer prices has significantly decreased that benefit and the differences between summer and winter prices.

Futures Contracts ("Futures")

Futures contracts are contracts to buy or sell a specified quantity of a commodity at a specified date in the future. Futures prices are based upon what buyers and sellers would pay today for gas delivery at some point in the future. It is possible to enter into a futures contract, typically with a producer or wholesaler, for physical gas, or a purely financial instrument, where delivery is not contemplated, such as is traded on the NYMEX[2].

The hedging strategy may be engaged in directly by the LDC, or it may require those terms in contracts from its suppliers. Typical strategies include:

- Locked-in or fixed pricing typically means that gas delivered to the LDC will be at a specified price, and either the LDC itself or the supplier has purchased futures contracts to protect those prices.
- Price caps, whereby the price of gas to the LDC will not exceed a specified level ("ceiling" price). This is typically accomplished by the LDC or the supplier buying "call" contracts, the right to buy at specified prices. Those rights would be exercised if the market price exceeded the specified "strike price."
- Collars - because price cap contracts have costs associated with the perception of risk (in addition to transaction costs) an LDC or supplier may also simultaneously enter into contracts at a "floor" price. That is, regardless of how low the price drops, the LDC or

[2] Only a few percent of all gas contracts traded on the NYMEX are actually exchanged for physical gas supply.

supplier agrees to pay the specified price. A "cost-less" collar is when the netting of the purchase costs associated with the ceiling price contract and the revenue from the floor price contract are equal, netting to zero. The LDC or supplier has then guaranteed that prices will fall into the range between the floor and ceiling prices.

3. CG&E's Hedging Policy

The Enterprise Credit Risk Management Policy, adopted in March 2003 and replacing an earlier policy from April 1999, outlines *"...credit risk management policies and procedures for wholesale energy commodity transactions including the purchase, sale or exchange of energy related commodities, structured transactions, commodities swap agreements or option contracts for energy related commodities including, but not limited to, electricity, natural gas, crude oil, emission allowances and coal."* It defines credit risk and market risk.

Credit risk is a function of the value of the positions exposed, the probability of default, and the value that may be recovered in the event of default, and includes the following components:

- default risk – the risk of failure to pay or perform or to provide adequate security or assurances
- collateral risk – the risk associated with credit enhancements (e.g., parent guarantees, letters of credit, deposits or prepayments)
- concentration risk – the risk that the trading portfolio is dominated by less than favorable risk-rated counterparties or by one type of entity
- settlement risk – the risk of non-payment by a counterparty.

Market risk relates to the risk of changes in the market value of a particular commitment. Credit risk and market risk are interrelated, as market movements will impact the value of credit risk positions over time.

CG&E's Credit Department is responsible for overseeing all aspects of credit risk management, including administering and enforcing the policy and programs, and all aspects of counterparties' risk profiles, including credit ratings, credit limits, credit exposure and monitoring all of them on a continuous basis.

The Credit Department assesses the creditworthiness of each counterparty or its credit enhancement provider by looking at its business profile, its financial profile and its external credit rating. This is required to be performed for all new counter parties, at least annually thereafter, and when additional information becomes available which may affect credit conditions. The Department uses its own risk rating system, from 1 (strongest, comparable to "AAA" rating) to 6 (weakest, comparable to "B" rating). The Department also establishes a credit limit for each counterparty, as specified in a table of approval limits set froth in the Policy.

4. CG&E's Hedging Program

2001-2002 Winter

CG&E developed a specific hedging plan for each of the winters during the Audit Period. The plan for the winter of 2001-2002 called for hedging between 50% and 75% of CG&E's winter base gas supply, which represented about 46% of the company's total Winter GCR supply under normal conditions. The schedule for acquiring hedging products specified the following minimum and maximum monthly purchases:

Month	Jul 2001	Aug 2001	Sept 2001	Oct 2001
Minimum	20%	30%	40%	50%
Maximum	75%	75%	75%	75%

For example, during July, CG&E was required to purchase at least 20% and no more than 75% of its normal winter base gas requirements for GCR customers. The specified percentages applied in the aggregate and did not apply to any particular months.

CG&E does not purchase any financial contracts (e.g., NYMEX futures contracts). It enters into contracts for physical delivery during specified winter months at NYMEX futures prices. The plan called for purchasing approximately 30% of the supply using fixed price contracts with cost averaging and the remaining 20-45% of the supply using fixed price contracts without averaging, price caps or collars. The actual prices paid were NYMEX Henry Hub prices less the basis differential between the delivery point and Henry Hub (to account for the fact that the delivery points are typically upstream of the Henry Hub, and therefore the transportation cost to that point is lower).

2001-2002 Results

Excluding storage, CG&E actually hedged approximately 7.8 million dth for the 5 winter months, using fixed price contracts without cost averaging, fixed price contracts with cost averaging, and collars. Contract prices ranged from a low of $2.15 to a high of $5.20. For those collars used, the maximum floor-ceiling price range was from $2.15 to $3.95.

2002-2003 Winter

For the 2002-2003 winter, CG&E's plan called for hedging up to 65% of its total normal winter base gas for GCR customers, which represented about 38% of the total supply during a normal winter. For this winter, CG&E did not set a specific schedule for acquiring hedging products, or a schedule that specified minimum and maximum monthly purchases.
CG&E continued its practice of purchasing only physical contracts with and without cost averaging, and collars, but discontinued using price caps.

During the summer of 2003, CG&E hedged approximately 4.5 million dth, using fixed price contracts with cost averaging, at a price of $2.70 per dth.

2002-2003 Results

Excluding storage, the company actually hedged approximately 4.7 million dth for the 5 winter months, using fixed price contracts with cost averaging and collars. Contract prices ranged from a low of $3.88 to a high of $4.90. For those collars used, the maximum floor-ceiling price range was from $3.92 to $4.90.

Ongoing Plan

Based on its experience the prior two winters, CG&E implemented a hedging plan on a continuous basis, for both winter and summer. The plan provides that for winter supply, the company will hedge between 20% and 70% of its base normal winter GCR supply, and for summer, up to 50% of total normal weather base supply. This represents approximately 38% of the normal winter base GCR supply and 63% of normal summer base supply. The schedules to be used are as follows:

Percent of Base Supply Hedged for Upcoming Winter

Month	April	May	June	July	August	September	October
Minimum	0	0	0	0	10	15	20
Maximum	25	25	50	50	75	75	75

Percent of Base Supply Hedged for Upcoming Summer

Month	November	December	January	February	March
Maximum	0	0	0	0	0
Minimum	25	25	25	50	50

The company continued its practice of purchasing only physical contracts with and without cost averaging and collars.

C. Conclusions

1. CG&E has a reasonable Credit Risk Management Policy which appropriately recognizes the various exposures in the gas purchasing business.

The policy identifies the various elements of counterparty risk, provides criteria for evaluating those risks, and specifies a rating system. It provides a framework for the evaluation of and analysis of counterparty risk.

2. The Credit Risk Management Policy appropriately assigns responsibility to the Risk Management Department to provide risk management expertise and services.

The organizational placement of the above functions separate from the personnel negotiating and executing the contracts provides a level of checks and balances, and provides necessary expertise which applies to other activities beyond gas procurement (e.g., electric procurements). As that function requires a specialized skill set which is for the most part non-specific to the particular energy-related commodities, it represents an efficient and effective structure.

3. CG&E's hedging policy has evolved over recent years, including the Audit Period, as the personnel gained experience and as the marketplace evolved and changed.

For most LDCs, price hedging other than that which occurred as a natural by-product of use of storage is a relatively new endeavor outside of the realm of their historic experience and their expertise. In most jurisdictions, LDCs were required or strongly encouraged to buy gas at market prices. As market prices became more and more volatile, many regulatory jurisdictions, including Ohio, have allowed or encouraged LDCs to take prudent steps to mitigate that price volatility as part of the management of the gas supply function.

This has been a learning experience for most LDCs, including CG&E, as the attributes behavior of commodities markets is very different from that of the physical markets. Thus, CG&E has proceeded in a cautious and orderly fashion by developing general plans pre-season, by limiting hedging to base gas levels, and by requiring the suppliers to perform the implementation of the financial hedging instruments.

4. It is appropriate that CG&E has proceeded cautiously in developing and executing its hedging policy, but it is now time to develop a broader approach to hedging activities. *(Recommendations #1 and #2)*

Financial markets offer instruments with a broad range of risks and rewards. By avoiding the financial markets entirely, CG&E has avoided most of the potential for entering into high risk contracts. However, this approach does have its downside. By dealing only in physical contracts with suppliers and wholesalers, and by requiring them to provide the hedged products, CG&E may incur additional costs. Because it goes out for bid on those contracts, CG&E believes that it is getting the best available price. However, it has not explored the costs of entering into the financial contracts separately from the physical contracts. While CG&E does not, at this time, have the expertise to do so, and states "we're not a trading operation,' neither are most producers and wholesalers. (Most of the ones that were in this business are out of the business one way or another.)

There are several other disadvantages of avoiding financial markets in the hedging program. Such a position limits the range of options CG&E can ask for because it needs to keep the bidding process and the bids fairly simple. Another disadvantage of staying out of these markets is that it severely limits CG&E's ability to make changes, since it is now locked into physical contracts for physical deliveries.

5. CG&E's hedging activities have produced a net savings for customers over the Audit Period, although the effect was not consistent over the two years.

As compared to the market prices, (*Inside FERC* First-of-Month index price, which would have been the effective price if CG&E had bought month-to-month gas), for the 2001-02 winter, the company's strategy yielded a price approximately $5.7 million higher than index prices. For the 2002-03 winter, the same comparison shows that CG&E paid $6.7 million less than market price.

Thus, for the two winters during the Audit Period, CG&E realized a net savings to ratepayers of about $1 million.

This savings number should be read with a note of caution, since the primary purpose of the hedging program, as stated by CG&E, is to dampen commodity price volatility. Further, while it may be possible to "beat the market," which Gas Commercial Operations stated was a secondary goal of the hedging program, in Liberty's view it is highly unlikely that it can be achieved using only physical contracts, and without dedicating knowledgeable staff experienced in these matters.

6. The effectiveness of storage as an offset to higher winter prices appears to have ended.

The experience of this past summer, with average prices in the $6/dth range, may have signaled an end to the historic summer offset to higher winter gas prices. While it is difficult to say whether this will be a long-term effect, it appears to be a fact for the near and intermediate term. Storage gas will continue to be a winter price hedge to the extent that the price of gas in storage will be known at the beginning of the winter season, so that the price stability effects of storage gas will continue to be available.

7. The goals and objectives of the hedging program are very broad, making measurement of success difficult, and may be unachievable in part without significant additional expertise. (*Recommendation #3*)

Gas Commercial Operations employees generally stated that hedging was primarily used to dampen price volatility and secondarily to achieve better prices. While both are reasonable and laudable goals, they are vague and unfocused, and in the latter case, very difficult to achieve.

In essence, CG&E's policy is that it will hedge somewhere between 20% and 75% of base winter gas, at fixed prices or collars to be determined on an ongoing basis, and that coupled with the natural hedge from use of storage, about a third of its supply will be hedged. The policy gives no guidance as to what price swings are acceptable, how much dampening to provide, and how to measure success.

Achievement of the secondary goal requires the company to "beat the market." While there are reputable firms that claim to have achieved this on a fairly consistent basis, it is unlikely that CG&E or most other LDCs have the resources and expertise to do this. The Audit Period is a good example of the inconsistency – CG&E appears to have beaten the market by $1 million, but was $5 million higher the first year and $6 million lower the second year.

D. Recommendations

1. CG&E should continue to use physical contracts at market prices to lock in commodity supply volumes and develop a plan that specifies a phased approach to the use of financial contracts for its hedging activities. (*Conclusion #4*)

Contracts for future physical deliveries indexed to market prices in effect at the time of delivery would provide the same security of supply CG&E now enjoys. Financial contracts could then be used (consistent with the cautions expressed in Recommendation 2 below, and the suggested outline for a plan provided below) to achieve whatever price goals or mitigation objectives the company set, with the added advantage of an ability to change positions over time as market conditions change.

A downside of the existing approach is that it sometimes locks in, prior to the commodity RFP process, suppliers who might not otherwise make the cut, and also locks in the company for the entire hedging period. It may also be a more expensive policy, as it makes the suppliers and wholesalers, who for the most part are not traders, the "middlemen" in the hedging process. And, it can make it difficult or expensive to change course or liquidate a position when changes occur in the market.

Liberty recognizes that any financial hedging program carries a certain level of risk, but that properly managed, will provide benefits that offset these risks. Thus, a carefully developed plan that specifies a phased approach to the use of financial hedging is important. Such a plan must include consideration of levels of expertise required, and the need for appropriate procedures detailing how CG&E would step its way into financial hedging such that lessons learned from early experiences could be fed back into the program for enhancement of future activities. The plan should include the types of exploratory financial hedging activities that are acceptable, and those that are not. And the plan should stress the need for tight controls, and control procedures, on hedging activities such that the inherent risks are appropriately managed, and communicated to senior management levels within the company.

Liberty is not recommending that CG&E establish formal trading operations, with respect to beginning its financial hedging program. In summary, what Liberty is recommending is that CG&E include the following in its plan for financial hedging:

- Define internally the objective of its hedging program;
- Develop the necessary analytical framework for implementing the chosen objective;
- Implement the necessary controls as a foundation for the program;
- Recognize and plan for the administrative and financial support requirements associated with the development of the financial hedging program.

2. **CG&E should re-examine its hedging policy and refine its objectives with respect to mitigating price volatility.** *(Conclusion #4)*

The current policy provides only very broad guidelines for hedging (e.g., between 20% and 65% of winter supply) with minimal guidance as to how and why to select the percentage and the time period within that framework. Taken together, these two weaknesses mean that Gas Commercial Operations staff has to make what is arguably a corporate decision, and then decide how to execute it, for every winter and summer season.

Alternatives that should be considered include whether the company should set an objective for price swings, whether hedging should be an ongoing, perhaps monthly process as opposed to a twice-a-year activity (e.g., hedging winter and summer prices), and whether some level of swing gas should be hedged.

To the extent that CG&E does begin to engage in financial hedges, which Liberty recommends, it is imperative that it put in stronger and far more specific guidelines and approval levels in its hedging policy. Financial hedges offer benefits, and all come with risks which must be well understood in advance of implementation. Certain types of instruments and strategies are highly inappropriate for an LDC, while others may be appropriate within specified bounds and with specified approval levels within the company.

3. **CG&E should explore the use of outside assistance and/or additions to staff as well as commercially available tools in its hedging program.** (*Conclusion #7*)

CG&E should consider enhancing its hedging program through procurement of outside services, augmenting its staff, or both. There are products on the market designed to address market price volatility, and some claim that over time they have beaten market prices fairly consistently, while noting that past performance is no guarantee of future success. CG&E has indicated some level of examination of such products but was deterred by the price of the products. However, relative to the swing difference between hedged and market prices that the company has experienced, the price is not that great. Further, CG&E is paying a price for requiring suppliers to provide price hedging – it is just not explicitly identified because it is buried in the price of the commodity.

In conjunction or alternatively, CG&E could augment its staff with one or more individuals who are experienced in the financial markets, in the use of hedging instruments, and who understand the nature of the LDC business. At this time, Gas Commercial Operations does not have that level of expertise, nor does it have the staff and the time to dedicate to acquiring that expertise.

In Liberty's view, either or both of the alternatives above require, as a prerequisite, implementation of the preceding recommendation, which calls for the development of a more definite hedging policy.

V. Gas Transportation

A. Scope

This chapter of Liberty's report addresses the following topics in CG&E's gas transportation program area:

- Non-Residential Transportation Programs (including interruptible transportation and flex-rate contracts)
- The Choice Program (including The Energy Cooperative Litigation)
- The PIPP Outsourcing Program

B. Background

1. Non-Residential Transportation Programs (including interruptible transportation and flex-rate contracts)

Starting in the mid-1990s, CG&E introduced transportation programs for public authority and small industrial customers, which was subsequently expanded to residential customers under the Choice program. Today, approximately 40% of CG&E's total throughput is third party gas.

As times changed, LDCs also introduced additional options to avoid the loss of customers from their systems. One of the options used by CG&E has been flex rate contracts that are driven by customers who have viable alternatives. Such customers may have dual-fuel capabilities and may switch completely to the alternate fuel, they may have the opportunity to connect directly to the pipeline[1], or they may be considering leaving the company's service territory. Thus, it is in the best interests of the LDCs to negotiate special contracts with those customers, as any revenue the company receives above variable costs contributes a net gain to the company. If CG&E believes a customer has a viable alternative, it will seek to negotiate a flex rate contract with that customer. There are currently 3 customers on this type of contract. The floor price for such contracts is 35 cents/dth.

Most of CG&E's interruptible transportation customers are dual fuel, and about two-thirds of them have some level of firm supply for plant protection when alternate fuel is not available. Generally, those with propane/air systems are able to use those for heat as well as process uses.

Typically, curtailments, as temporary interruptions of service to interruptible customers are known, are called on the coldest days. On such days, heating loads are highest, and the system does not have the physical capability to maintain pressure to provide deliveries to all customers. Firm customers, who pay higher rates, receive priority while interruptible customers are subject to curtailment. CG&E attempts to give as much advance notice of a curtailment as possible, including advance notice about the possibility that a curtailment will be called, and is required by tariff to give at least 3 hours' notice. When a curtailment is scheduled, a text message is sent out

[1] Bypass was enabled by FERC's undbundling of the pipelines.

by CG&E to designated customer contacts, and these customer contact individuals are required to call in to the company to confirm receipt of the page and the terms of the interruption.

Curtailments as used by CG&E refer to the interruption of service to customers who voluntarily subscribe to Interruptible Transportation ("Rate IT") Service. Such customers are typically dual fuel commercial and industrial customers who are able to alternate between competitive fuels depending upon price and availability. Under this service classification, customers agree to interrupt their consumption taken under this service classification upon request by the company. The company may initiate a curtailment when, in its judgment, service to firm customers is jeopardized. Curtailment procedures are contained in the Cinergy *Gas Operational Curtailment Plan, 2003-2004*, most recently revised December 2, 2003. This plan replaced an earlier, much less detailed plan dated July 30, 1998.

CG&E has 4 levels of interruptible service, with Level 1 being most likely to be interrupted and Level 4 least likely. The categorization is based on the customers' location on the CG&E system and the pressure behavior of the system on peak days. Having four levels of interruptible service allows CG&E the flexibility to interrupt only those customers necessary to preserve the integrity of the system. Approximate temperatures at which the levels are interrupted follow:

Level 1:	5 degrees F
Level 2:	0 degrees F
Level 3:	-5 degrees F
Level 4:	-10 degrees F

Within a level, the company may curtail only to the extent necessary to allow continued service to firm customers. The Plan referenced above lists 213 interruptible customers by level.

All interruptible customers have Metscan or Metretek automated meter reading devices on their meters, so that the company knows whether they have complied with a directive to curtail their service. If the customer does not comply, the company can physically shut them off by sending out a crew to turn off service. Any usage beyond the specified time limit is subject to a penalty price at the highest cost of supply experienced by the company plus a pipeline demand charge.

2. The Choice Program

Beginning in 1997, residential customers have been eligible for residential firm transportation service (retail access) service from suppliers other than CG&E under Rate RFT, the Residential Firm Transportation Service Tariff. All residential customers are eligible except for those whose accounts are past due or who fall into arrears after choosing the service. Billing for the provision of the commodity may be by CG&E or the supplier, depending upon the arrangements they have worked out. Residential customers enrolled in income payment plans pursuant to Ohio Administrative Code Rule 4901:1-18-04 ("PIPP" customers) are eligible only through a PIPP supply pool, discussed later in this chapter.

There is no charge for the initial change in natural gas supplier from CG&E to another supplier, but subsequent switches either to another supplier or back to CG&E are charged a $5.00 switching fee. Regular monthly charges to RFT customers include:

- An administrative charge of $6.00
- A charge for Rider AMRP, the Accelerated Main Replacement Program
- A transportation charge of $0.18591 per hundred cubic feet of gas delivered
- Various "adjustment" riders: Rider PIPP, Rider STR (state taxes), Rider CCCR (Contract Commitment Cost Recovery Rider), Rider GCRT (GCRT Transition Rider), and Rider ETR (Ohio Excise Tax Liability Rider)
- Adjustments for pipeline refunds or costs

The company maintains a list of eligible suppliers and their contact information on its website, along with an overview of the program, a list of frequently asked questions with responses, and other program information. Also on the website is information for suppliers and an application form for those who wish to participate in the program.

The Energy Cooperative Litigation

After Cinergy decided to remove itself from the competitive supplier business, it sold its supply affiliate, Cinergy Resources, Inc. to Licking Rural Electrifications, Inc. d/b/a The Energy Cooperative (the "Cooperative") in February 2000.

On January 1, 2001, CG&E received a fax from the Cooperative stating that they were out of balance in the company's favor (that is, the Cooperative had overdelivered gas and had a positive balance with the company) and were stopping nomination and delivery of gas. Subsequently, within 8 to 10 days, the company declared the Cooperative in default and bought gas to maintain service to those customers. After declaring the Cooperative in default, over the billing cycle January 15 to February 15, CG&E returned those customers to CG&E sales service.

In February 2001, three class action lawsuits were brought against Cinergy, CG&E and Cinergy Resources by customers, relating to the removal of the Cooperative from the Choice program and the failure to deliver gas to the customers. As of the filing of Liberty's report, a tentative settlement has been reached in a class action brought by residential gas customers who participated locally in the Public Utility Commission of Ohio's Natural Gas Choice Program. Also, as of this time, CG&E states that the incremental gas purchase costs associated with the Cooperative situation have not been passed through the GCR. In view of the fact that this situation has not been finally resolved, it would be appropriate for the next management/performance auditor, and the next financial auditor, to examine the final resolution of The Energy Cooperative litigation.

3. The PIPP Program

Under the provisions of a June 18, 1998 Commission Finding and Order, LDCs were required to identify alternative natural gas suppliers for the provision of commodity service to the

Percentage of Income Payment Plan (PIPP) customer class. After a bid process and evaluation of responses, CG&E selected Volunteer Energy Services, Inc., a FirstEnergy Company[2] as supplier to the PIPP customer class. By application of August 14, 2000, CG&E requested Commission approval of a supplier agreement covering the period September 1, 2000 through September 1, 2001. The agreement was approved by the Commission by Entry dated August 31, 2000. Subsequently, CG&E conducted further annual evaluations and received Commission approval for each of two additional years, through September 1, 2002 and September 1, 2003.

For the next year, CG&E issued an RFP in April 2003, and again in July 2003, to 42 potential suppliers. No responding bids were received, and by report dated August 5, 2003, CG&E notified the Commission that it would begin supplying the PIPP customers upon the expiration of the FirstEnergy contract.

C. Conclusions

1. CG&E's use of levels of curtailment recognizes the physical configuration of the operating system and is structured so as to minimize the number of customers unnecessarily interrupted.

On cold days, when system load is peaking, LDCs curtail interruptible customers so as to maintain system pressures. However, most LDCs do not experience uniform pressure drops across the system. Some parts of the system may be more constrained than others, more heavily loaded, or both. In that sense, all interruptible customers are not created equal – some are curtailed more frequently than others.

In the early 1990's, when a curtailment was called, all interruptible customers were curtailed. Recognizing that on occasion some interruptible customers were curtailed needlessly, in 1999 CG&E implemented four different levels of curtailment, based primarily upon customers' locations on the system. Customers are assigned[3] curtailment levels 1 through 4, with Level 1's curtailed first and Level 4's interrupted last.

2. The history of curtailments on the CG&E system indicates a low level of interruptions over a long period of time.

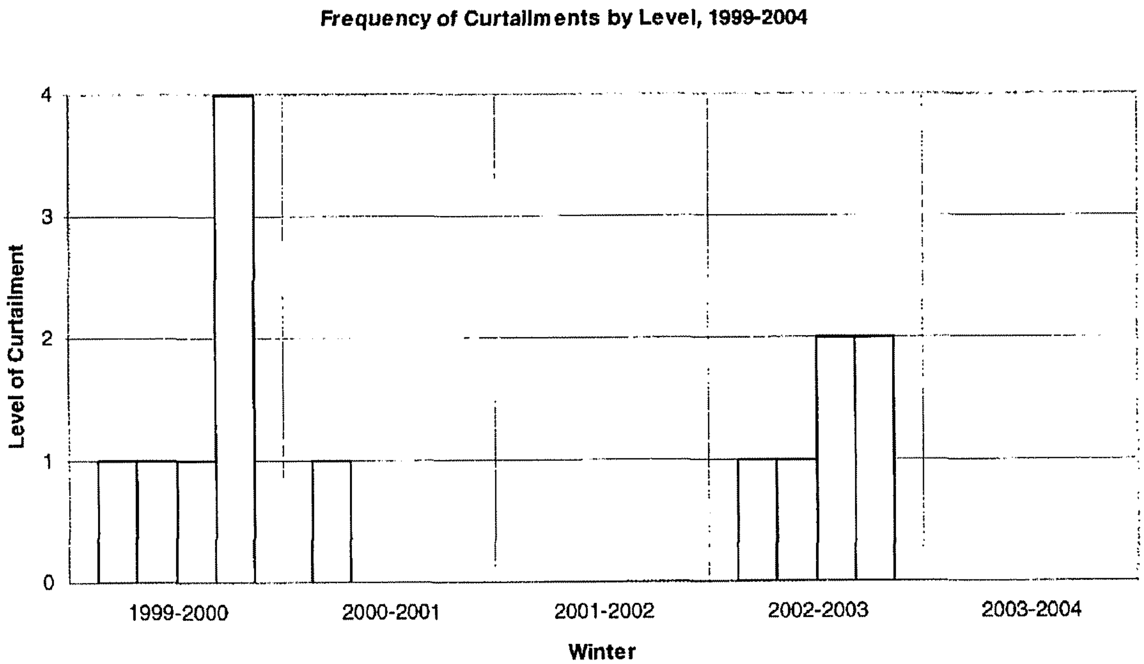
Over the period 1979 – 2002, there have been a total of 43 curtailments, 16 full day and 27 partial day curtailments. The relative infrequency of curtailments over a long period of time suggests that it may be appropriate to reexamine the interruptible rate offering and the interruptible rate structure.

Since 1999, when the system of levels of interruption was introduced, there has been only one Level 4 and no Level 3 interruptions. This means that with one exception, Level 3 and 4

[2] Volunteer Energy Services was later renamed FirstEnergy Resources

[3] Because curtailment level is based upon physical operation of the system and the customers' locations on it, they do not have a choice as to what level they are assigned.

customers have had the equivalent of firm service. Figure V.1 below depicts the number and level of interruptions since the practice began in the1999 – 2000 winter.



Frequency of Curtailments by Level
1999-2004
Figure V.1

The construction of the new C314 line, which was completed in November 2003, will require a reevaluation of the curtailment levels, since the increased system pressure stability will allow some redistribution of customers to higher levels (i.e., lower likelihood of interruption).

3. **It may be appropriate to revisit the interruptible rate structure in the next major rate case.** (*Recommendation #1*)

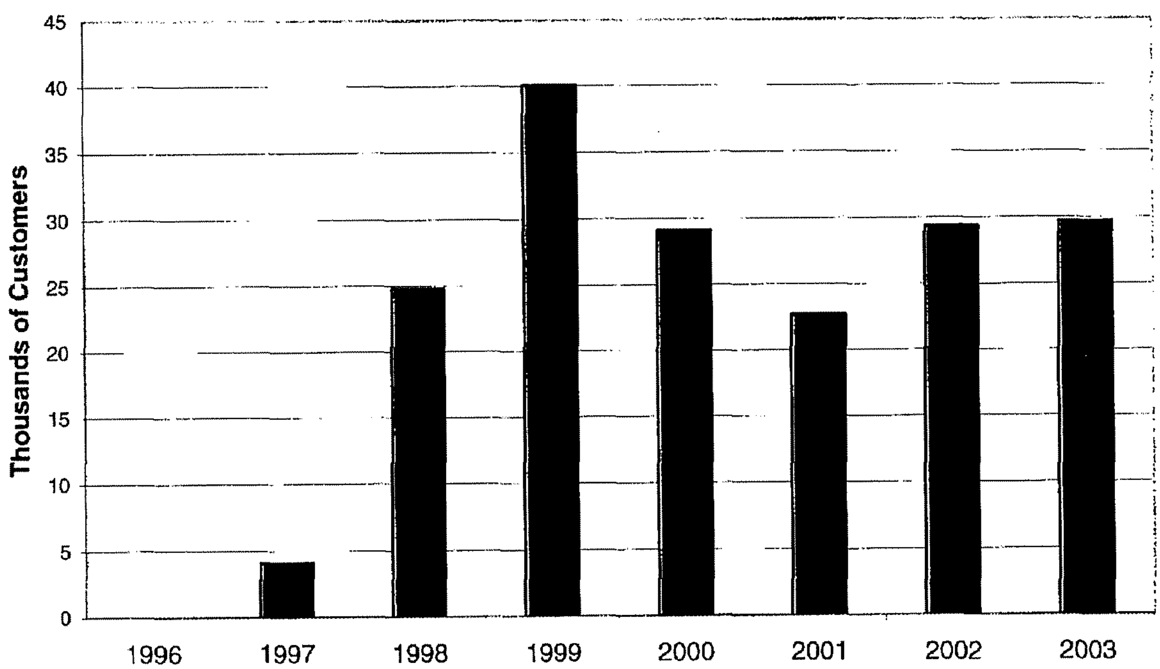
From an equity perspective, it does not appear that customers with significantly different probabilities of curtailment should be paying the same rate. While no customers on the CG&E system are curtailed frequently, during the 5 year experience with levels of interruption, some customers have been curtailed only once, while others have been curtailed 9 times.

4. **The Choice program has suffered significant setbacks coincident with the general problems in the gas industry and the particular problems with The Energy Cooperative.** (*Recommendation #2*)

CG&E has by far the lowest penetration of customer migration to alternate suppliers of any of the major Ohio gas companies – less that 30,000 customers, or approximately 9% overall, compared to 54% penetration for the LDC with the highest migration. Of the 5 suppliers nominally serving Choice customers on CG&E's system in 2003, only one supplier has a significant market share and is currently soliciting customers, while the other LDCs have 9, 8 and 3 suppliers on their respective systems. Earlier, the company had as many as a dozen suppliers, with over 1,000 customers each, including a CG&E affiliate, Cinergy Resources, which was sold as discussed below.

In part, the low penetration rate is due to the January 2002 reassignment of almost 18,000 customers from The Energy Cooperative as a result of the previously described situation. And, migration has been essentially flat for 3 of the 4 Ohio companies in the last year; the exception is Vectren Energy Delivery of Ohio, whose program was starting up in the beginning of 2003. Unfortunately, this is a fairly common scenario around the country, as many suppliers have pulled out of the market or ceased operations.

Figure V.2 below shows the market penetration of the RFT program (excluding PIPP customers) by year since its inception.



Market Penetration of Choice Program
Figure V.2

5. **The PIPP program has suffered a setback similar to that experienced by the Choice program.** (*Recommendation #2*)

On two occasions in 2003, CG&E made a good faith effort to find a PIPP supplier. In particular, on the second effort, CG&E contacted 42 potential suppliers. The lack of supplier interest in participating in the PIPP program offers convincing evidence that the marketplace is not willing to participate as the program is currently configured. It is difficult to say, at this time, whether this is a temporary condition resulting from the recent problems in the energy industry, or a longer term problem which requires a structural solution.

6. The Contract Commitment Cost Recover Rider assesses a surcharge to avoid the potential for stranded costs.

All firm customers served under the Residential (RS), General (GS), Firm Transportation (FT), or Residential Firm Transportation (RFT) Tariffs are assessed a surcharge to recover fully any potentially strandable costs, e.g., upstream pipeline commitments, propane costs, or contracts which may not otherwise be recovered when customers switch from RS to RFT service. The surcharge is recovered through the Contract Commitment Cost Recovery Rider (CCCR), which is updated concurrently with the GCR filings. The most recent level of the charge, to be in effect June – August 2004, is $0.03 per hundred cubic feet.

7. A portion of the output of the propane facilities is dedicated to the firm transportation customer classes.

In CG&E's calculation of design day, 21% of design day demand is met with propane. Accordingly, the company makes sufficient propane available up to 21% of each FT and RFT supplier's design day requirements. Thus, a supplier may, but is not required to deliver in excess of 79% of its design day quantity, and the balance is met by the company. In essence, the suppliers have recall rights to 21% of the propane plants' output.

This practice provides a relatively cheap form of insurance to CG&E that suppliers will have resources available on peak days. In practice, it is rarely invoked. During the Audit Period, there were only 9 occasions when a supplier met the 79% requirement but did not deliver its full Targeted Supply Quantity, and only 4 occasions when a supplier failed to meet the 79% requirement. In all cases, the amount of gas involved was very small.

D. Recommendations

1. CG&E should reevaluate its assignment of curtailment levels recognizing the benefits of the new C314 line, and should consider modifying the interruptible rate structure in next major rate filing. (*Conclusion #3*)

The improved system stability benefits made possible by the new C314 line offer an opportunity to revisit CG&E's curtailment levels and associated rate structure. In conjunction with that review, or as a follow-on, CG&E should look at its interruptible rate structure. It is clear from the data shown above that Level 1 interruptible customers are interrupted more frequently than Level 4 customers. That is to be expected, and is in fact the underlying premise of the categorization. It then seems to follow that customers are receiving a different level of service, which should be recognized in the rate structure. This is a well- accepted concept; different classes of interruptible service are fairly common in the industry.

2. **There are no quick fixes for the Choice and PIPP programs. They should be maintained at the current level and carefully monitored and evaluated.** (*Conclusions #4 and #5*)

The energy industry is recuperating from severe injuries at the national level. As well, the Energy Cooperative problems and litigation dealt a further setback to Choice at CG&E. However, the programs at two of the other Ohio LDCs have remained relatively flat, while the third, in startup mode, has grown, suggesting that some of the problem is localized to CG&E. And, there are at least 9 Choice suppliers operating in the state. Thus, it would be premature to make any significant changes absent compelling evidence to support such changes. It would appear appropriate, however, to examine the programs carefully to determine whether any structural impediments exist in the CG&E programs.

VI. Operational Issues

A. Scope

This chapter of Liberty's report addresses the following topics in CG&E's operations relative to gas supply:

- Gas Dispatch
- Propane Operations
- Lost and Unaccounted for Gas
- Emergency Curtailment Procedures and OFOs

B. Background

1. Gas Dispatch

Prior to December 1, 2001, CG&E's procedures provided that its dispatchers would log in to the pipeline websites and make nominations under the various contracts held by the company. With the initial hiring of Mirant as Asset Manager, which took place close to the beginning of the Audit Period, the actual nominations have all been performed by the Asset Manager. Dispatch is performed jointly for all three Cinergy companies.

CG&E developed a set of procedures for its Virtual Dispatch, referred to earlier in Chapter III, Gas Supply Management. This is a practice by which the company can track the Asset Manager's performance relative to how CG&E would dispatch the system, and to develop and compare the costs accordingly.

Virtual Dispatch involves CG&E determining its sendout requirements for the day and reporting these requirements to its Asset Manager (currently CM&T). The Asset Manager in turn uses its resources as it sees fit to meet those sendout requirements, and may use the resources differently from what the Virtual Dispatch dictates as long as CG&E's total sendout requirements are met. CG&E is billed by the Asset Manager based upon the costs associated with the Virtual Dispatch. CG&E independently tracks all gas supply conditions, including storage inventory, on a virtual basis. The reconciliation of costs and storage balances are done at the end of each month.

Part of the virtual dispatch process considers storage balances that are taken into account with respect to the monthly minimum and maximum inventory targets from storage contracts in order to avoid any penalties for violating contract ratchet provisions. The virtual dispatch sheet also considers pricing of various gas supply contracts to determine the cheapest alternative, but currently does not evaluate available propane resources as part of this price ranking. Propane is only used as a last resort for purposes of meeting close-to-design day weather occurrences and potential peak hour demand. The propane facilities are not included in the virtual dispatch, as they are owned by CG&E.

2. Propane Operations

Propane is purchased from the Texon Terminals Corporation facilities in Mt. Belvieu, Texas, and shipped via pipeline to Todhunter, using Texon's contracts with Texas Eastern.

CG&E owns and maintains three propane peaking plants, Dick's Creek (northern part of the system), Eastern Avenue (downtown), and Erlanger (northern Kentucky, and shared 64%/36% with UHL&P), and the approximately 7 million gallons Todhunter storage cavern, less than a mile from the Dick's Creek plant. Todhunter is filled via the Texas Eastern Products Pipeline Company (TEPPCO) pipeline from the Texon Terminals Corporation in Mt. Belveiu, Texas. A CG&E pipeline then delivers the propane from Todhunter to the Dicks Creek plant.

Propane is trucked from Todhunter to the other two plants, where it is stored in underground caverns on site. Each of the caverns is some 400 feet deep, with two submersible pumps to pump out the propane. Each plant has two electric compressors, two vaporizers, and two natural-gas fueled boilers. The compressors have redundant electric feeds.

The plants were built in the 1940 – 1950 era, but despite their ages the company believes they are in excellent condition. The vaporizers and compressors are the original equipment; the boiler tubes and submersible pumps are fairly recent replacements. The company believes that they can be operated indefinitely as long as propane is available and temperatures are low enough for practical operation. The compressor units are maintained annually and the plants are tested periodically during the year. A review of the testing history indicates that each plant experienced a test run between 1 and 9 times each year, above and beyond its normal operating history. The plants have a spare parts inventory but no backup compressors.

3. Lost and Unaccounted for Gas (LAUF)

LAUF is a "catch-all" gas accounting category for all gas not captured in other accounting categories. While there is no industry standard or guideline for what is included, LAUF is loosely defined as the difference between gas purchased and gas sold, and may include operating losses, theft, customer service losses, measurement error, energy to volume conversion error, and company use. The following definitions are general in nature, and do not necessarily represent the categorization used by all LDCs:

- Operating losses include leaks and maintenance losses (e.g., line purges);
- Theft includes gas used but not metered, via meter bypass, meter tampering, unauthorized tapping of mains or service lines or similar action;
- Customer service losses typically include metered usage for which the company is unable to find the customer to bill (which does not include uncollectibles, where a customer was billed but has not paid);
- Measurement error reflects the difference between actual quantities delivered vs. the measurement on customer meters. This is usually a loss since meters are typically set so that any metering error will be on the "slow' side, i.e., in the customer's favor;

- Conversion error – LDCs typically take gas from pipelines on an energy basis, measured in dekatherms, and bill customers on a volumetric basis, measured in cubic feet. Since the energy content of the gas ("gas quality") may vary over time as well as across pipelines, this conversion typically utilizes some broad averaging algorithm. *Unlike the other LAUF categories, conversion error may be positive or negative;*
- Company use represents gas used in company buildings, compressor stations, and other company facilities. Typically, larger uses such as buildings are metered, but some smaller uses may be unmetered.

4. Emergency Curtailments and Operational Flow Orders (OFOs)

Emergency curtailments occur when there is a shortage of natural gas supply or transportation which would require some firm customers to reduce or cease their usage of gas. As the name suggests, this is a highly unusual situation; company personnel could not recall a situation where this has happened. Emergency curtailment would be consistent with Administrative Order 46 on file with the PUCO.

As required by the PUCO, CG&E has on file a set of emergency curtailment procedures which specify the order of emergency curtailment should it become necessary. The procedures would be used after all IT customers are off the system. The first to be curtailed in an emergency would be large industrial and commercial customers, and the last would be human needs customers. Emergency curtailment would not necessarily be a system-wide situation, but could be implemented on a part of the system, depending on the cause of the emergency, and the particular pipeline(s) causing the situation.

The company may issue OFOs to suppliers to require them to match or exceed the needs of their customers (cold weather OFO) or match or underdeliver to their customers in the case of a warm weather OFO. Violations in the former case can result in charges to the supplier equal to the highest cost of gas on the system while in the latter case the suppliers will be paid the lowest cost of gas on the system.

During the 5 year period 1999 – 2003, the company called 13 cold weather and 18 warm weather OFOs. For the audit Period, those numbers were 8 and 6, respectively.

C. Conclusions

1. The propane plants are a reliable and relatively low cost needle peaking source.

As described previously, the plants are well maintained and have been upgraded and automated to some extent. In the past, they required a maintenance staff of some 40 employees, but that staffing has been cut in half. During the summer season, the plant staff is assigned to other tasks, such as maintenance and corrosion work.

Overall, the company stated that the plants cost approximately $1 million a year to maintain and generate $4 to $5 million in benefits.

2. CG&E has an ad hoc Gas Measurement Committee which addresses a variety of measurement issues, including LAUF.

The ad hoc Gas Measurement Committee consists of 12 members, including the Supervisors of Gas Control, Technical Services, the Gas Measurement Center, and Gas Rates and Transportation Programs, 3 Senior and one Staff Engineers, a Customer Representative, a Senior Engineering Technologist and 2 Billing Analysts.

Over the last 3 years, the Committee became concerned about the accuracy of gas measurement at large metering stations. They have made some changes at gate stations and looked into measurement issues at large customer metering points. Overall, the Committee has looked at some of what they believe to be the major components of LAUF, including receipt point and large customer meters and losses associated with third party damages, but have not identified all of the components.

3. CG&E computes Lost and Unaccounted for Gas amounts on a monthly basis and recovers those amounts through the GCR.

CG&E computes Lost and Unaccounted for Gas as the difference between gas delivered to the company and gas delivered to the customers, amounting to the difference between volumes metered at the citygate less the volumes measured on the customer meters. The company collects the data and computes the percent LAUF monthly on a rolling 12-month basis.
Table VI.1 indicates those results on an annual basis:

12 months ending	Per Cent LAUF
June 1994	1.9
June 1995	2.2
June 1996	1.4
June 1997	1.5
June 1998	0.5
June 1999	0.7
June 2000	0.9
June 2001	0.9
June 2002	1.0
June 2003	1.7

Lost and Unaccounted for Gas
Table VI.1

The LAUF factors based on the 12 months ended June of each year are then applied to monthly sales volumes to develop a "gross-up" factor to be applied to transportation customers to cover the costs of LAUF. (LAUF for sales customers is recovered through the GCR) That particular 12 month period is used because of the wide swings between citygate and customer readings, particularly during the winter months, resulting from the lag introduced by cycle billing.

4. CG&E does not have a good handle on the actual levels of LAUF or the causes of it. *(Recommendation #1)*

CG&E has not performed any LAUF studies that current employees can recall. Gas Control provides a monthly report, which is rolled into a monthly report, accumulated quarterly, and put into the accounting filings. However, that is a gas accounting filing, and does not identify sources of losses or associated volumes.

As described previously, CG&E has looked at some contributing factors, including certain specific citygate and large customer metering and third party damage. One employee tracks third party damages and calculates an amount for lost gas to bill the responsible party.

The company cited an improvement in its leak handling from the year 2000 to the present. Going into 2000, they had some 7,000 leaks on the books, which have now been reduced to about 900. During the last 3 calendar years, they repaired approximately 6,000, 5,000 and 4,000 leaks.

The wide variations from year to year and percentages of 0.5% and 0.7% indicate that the data is unreliable. Given all of the factors described previously and the company's relative inattention to it, Liberty would expect to see figures in the 2% to 4% range.

5. CG&E's curtailment plan for non-emergency curtailments is thorough and comprehensive, and represents a significant improvement over the prior plan.

The plan explains when a curtailment may be called, when and by whom, and lays out the responsibilities of the different individuals for implementing and communicating the plan, both within the company and at each of its IT customers. It also lists procedures to be followed and specific steps to be taken by each of the individuals with designated responsibility. According to the plan, it is to be revised and redistributed annually. The plan also includes the names and home, mobile, and page contact numbers for some 58 key personnel, from Management, Pressure Control, Gas Commercial Operations, Engineering, Business Account Management, the Call Center, and Customer Service. Further, in addition to the identification of the level of curtailment of each of the interruptible customers, it includes addresses and account identification.

The prior plan was far less comprehensive in every aspect, and apparently had not been updated since 1998.

6. CG&E's plan for emergency curtailments has not been updated to reflect the current state of its transportation programs. (*Recommendation #2*)

While emergency curtailments are few and far between, and employees cannot remember the last one on the company's system, they are nonetheless contingencies for which the company must be prepared. The company's procedures are well defined for both ordinary winter curtailments and emergency curtailments. However, the procedures were unilaterally developed by the company and may not reflect the current environment of multiple suppliers and to general service and residential customers. And, the company's schedule of emergency curtailment priorities may not necessarily be consistent with the agreements between suppliers and customers.

Further, with respect to emergency curtailments, the procedures were designed for a short term contingency, that is, how the company can quickly shed large segments of load. Should a curtailment last for an extended period of time, such as days or weeks, the company will have time to make physical adjustments to the system and alternative arrangements may be appropriate.

D. Recommendations

1. CG&E should undertake a focused two-part program, under the auspices of the Gas Measurement Committee, to more aggressively monitor and manage the LAUF program. The program should include the following: (*Conclusion #4*)

a. The collection and maintenance of accurate LAUF data, and;

b. Based on those results, a program to minimize LAUF on the CG&E system.

The low level of knowledge about LAUF indicates a weakness in CG&E operations. Liberty believes that the company's LAUF numbers appear low not because physical, gas accounting and measurement losses are very low, but because certain categories of losses tend to cancel each other. While CG&E is correct in focusing on large meters as one possible source of error, other categories with larger discrepancies are likely to be theft (unmetered consumption), customer service losses (metered consumption for which there is no responsible customer), and heat content to volumetric metering conversion.

For purposes of such a study, the Committee should be supplemented by representatives from the customer service area, who will be able to contribute to the knowledge base and plan of action for several of those categories. Further, since LAUF should be an ongoing concern at any gas utility, the Committee should be changed from its current ad hoc status to a standing committee.

2. CG&E should meet with suppliers, PUCO staff and the largest customers to review the emergency curtailment plan and procedures. *(Conclusion #6)*

The existing plan and procedures should be reviewed and reevaluated to ensure that they recognize any arrangements between suppliers and customers that may differ from CG&E tariffed arrangements with its customers. So long as the former arrangements are consistent with the governing regulations, they should be considered in the development of the plan and procedures. Consideration should also be given to whether and to what extent the plan should be modified to address longer term emergency curtailments, wherein physical changes (such as manual valve closings and regulator resets might be accomplished.

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The Cincinnati Gas & Electric Company

Independent Accountants' Report on the Uniform Purchased Gas Adjustment for the Year Ended August 31, 2003
In Response to Case No. 03-218-GA-GCR

THE CINCINNATI GAS & ELECTRIC COMPANY

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INDEPENDENT ACCOUNTANTS' REPORT

To The Cincinnati Gas & Electric Company:

We have examined the filings of The Cincinnati Gas & Electric Company (the "Company") that support the gas cost recovery ("GCR") rates for three-month period ended November 27, 2002, the three-month period ended February 28, 2003, the one-month period ended March 31, 2003, the two-month period ended May 30, 2003 and the three-month period ended August 28, 2003, and that relate to the reporting period for the year ended August 31, 2003, for conformity in all material respects with the financial procedural aspects of the uniform purchased gas adjustment as set forth in Chapter 4901:1-14 and related appendices of the Ohio Administrative Code. These filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to the fair determination of GCR rates calculated within the filings and whether those rates have been properly applied to customer bills based on our examination.

Our examination for this purpose was made in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining, on a test basis, evidence supporting the Company's computation of the GCR rates in accordance with those requirements and performing such other procedures, as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion. We did not make a detailed examination as would be required to determine that each transaction has been recorded in accordance with the financial procedural aspects of Chapter 4901:1-14 and related appendices of the Ohio Administrative Code. Our examination does not provide a legal determination on the Company's compliance with specified requirements.

In our opinion, the Company has fairly determined, in all material respects, the GCR rates for the three-month period ended November 27, 2002, the three-month period ended February 28, 2003, the one-month period ended March 31, 2003, the two-month period ended May 31, 2003 and the three-month period ended August 28, 2003, in accordance with the financial procedural aspects of the uniform purchased gas adjustment as set forth in Chapter 4901:1-14 of the Ohio Administrative Code and properly applied the GCR rates to customer bills.

Specific findings, which are presented for the attention of the Public Utilities Commission of Ohio ("PUCO"), are attached in a separate memorandum entitled "Summary of Findings."

This report is intended solely for the information and use of the Company and the PUCO and is not intended to be and should not be used by anyone other than these parties.

Deloitte & Touche LLP

May 21, 2004

THE CINCINNATI GAS & ELECTRIC COMPANY

UNIFORM PURCHASED GAS ADJUSTMENT RATES

The following is a summary of the uniform purchased gas adjustment rates subjected to our examination:

Period in Effect	Expected Gas Cost	Supplier Refund and Reconciliation Adjustment	Actual Adjustment	Balance Adjustment	Total Uniform Purchased Gas Adjustment
August 29, 2002 to November 27, 2002	4.222	(0.011)	(0.315)	0.096	3.992
November 28, 2002 to February 28, 2003	5.059	(0.064)	(0.209)	(0.228)	4.558
March 1, 2003 to March 31, 2003	5.955	(0.065)	0.175	(0.077)	5.988
April 1, 2003 to May 30, 2003	6.572	(0.065)	0.175	(0.077)	6.605
May 31, 2003 to August 28, 2003	6.782	(0.066)	0.891	0.527	8.134

THE CINCINNATI GAS & ELECTRIC COMPANY (THE COMPANY)

SUMMARY OF FINDINGS

STATUS OF EXCEPTIONS REPORTED IN PRIOR YEAR REPORT

In our prior year report, we noted two instances in which the actual adjustments (AA) included in the GCR rates effective during the prior year audit period were misstated due to errors relating to transportation customer billing adjustments. The Company included adjustments of ($312,500) and $99,407 in the AA for GCR rates effective May 31, 2003 in order to correct these errors.

In our prior year report we noted that, due to clerical errors in compiling total supply costs used to calculate the AA, the Company understated its supply costs by a cumulative net amount of $670. The Company corrected this error by adjusting the AA for GCR rates effective May 31, 2003.

OTHER MATTERS IDENTIFIED IN CURRENT YEAR EXAMINATION

Due to a clerical error, the Company overstated its total supply cost used to calculate the AA included in its GCR rate effective June 1, 2002. The Company has corrected this error by including a $9,000 credit in the AA calculation for August 2003 which was included in the AA portion of the GCR rates which were effective December 1, 2003.

Due to a clerical error, the Company understated the volume used to calculate the demand component of the expected gas costs ("EGC") rate in the filing effective June 1, 2002. This caused an overstatement of the EGC rate of $0.051 per MCF. This error was self-correcting in the calculation of the AA for GCR rates that were effective November 28, 2002.

Due to a clerical error, the Company overstated the estimated purchases used to calculate the commodity component of the EGC rate in the filing effective August 29, 2002. This caused an overstatement of the EGC rate of $0.001 per MCF. The error was self-correcting in the calculation of the AA for GCR rates that were effective November 27, 2002.

Due to a clerical error, the Company overstated the estimated purchases used to calculate the commodity component of the EGC rate in the filing effective March 1, 2003. This caused an overstatement of the EGC rate of $0.002 per MCF. The error was self-correcting in the calculation of the AA for GCR rates that were effective May 31, 2003.

Due to a clerical error, the Company understated the estimated purchases used to calculate the commodity component of the EGC rate in the filing effective May 31, 2003. This caused an understatement of the EGC rate of $0.002 per MCF. The error was self-correcting in the calculation of the AA for GCR rates that were effective August 29, 2003.

Due to a clerical error, the Company understated the estimated purchases used to calculate the commodity component of the EGC rate in the filing effective August 29, 2003. This caused an understatement of the EGC rate of $0.003 per MCF. The error was self-correcting in the calculation of the AA for GCR rates that were effective December 1, 2003.

* * * * * *

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY
GAS COST RECOVERY RATE CALCULATIONS

PARTICULARS	UNIT	AMOUNT
EXPECTED GAS COST (EGC)	$/MCF	4.222
SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT (RA)	$/MCF	(0.011)
ACTUAL ADJUSTMENT (AA)	$/MCF	(0.315)
BALANCE ADJUSTMENT (BA)	$/MCF	0.096
GAS COST RECOVERY RATE (GCR) = EGC + RA + AA +BA	$/MCF	3.992

RECEIVED
JUL 29 2002
GAS & WATER DIVISION

GAS COST RECOVERY RATE EFFECTIVE DATES: AUGUST 29, 2002 THROUGH NOVEMBER 27, 2002

EXPECTED GAS COST CALCULATION

DESCRIPTION	UNIT	AMOUNT
TOTAL EXPECTED GAS COST COMPONENT (EGC)	$/MCF	4.222

SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
CURRENT QUARTERLY SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	(0.004)
PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	0.000
SECOND PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	0.000
THIRD PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	(0.007)
SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT (RA)	$/MCF	(0.011)

ACTUAL ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
CURRENT QUARTERLY ACTUAL ADJUSTMENT	$/MCF	(0.098)
PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	(0.269)
SECOND PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	0.187
THIRD PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	(0.135)
ACTUAL ADJUSTMENT (AA)	$/MCF	(0.315)

BALANCE ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
BALANCE ADJUSTMENT AMOUNT	$	555,201.36
JURISDICTIONAL SALES FOR THE QUARTER	MCF	5,756,487
BALANCE ADJUSTMENT (BA)	$/MCF	0.096

THIS QUARTERLY REPORT FILED PURSUANT TO ORDER NO. 76-515-GA-ORD
OF THE PUBLIC UTILITIES COMMISSION OF OHIO, DATED OCTOBER 18, 1979.

DATE FILED: July 26, 2002

BY: JOHN P. STEFFEN

TITLE: VICE-PRESIDENT, RATES

SCHEDULE I

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

EXPECTED GAS COST RATE CALCULATION

DETAILS FOR THE EGC RATE IN EFFECT AS OF SEPTEMBER 1, 2002
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

DEMAND COSTS	DEMAND EXPECTED GAS COST AMT ($)	MISC EXPECTED GAS COST AMT ($)	TOTAL DEMAND EXPECTED GAS COST AMT ($)	
INTERSTATE PIPELINE SUPPLIERS (SCH. I-A)				
Columbia Gas Transmission Corp.	16,171,427	(98,323)	16,073,104	
Union Light, Heat, and Power Co.	647,568	0	647,568	
Columbia Gulf Transmission Co.	4,537,957	(25,019)	4,512,938	
Texas Gas Transmission Corp.	10,297,543	0	10,297,543	
Tennessee Gas Pipeline	1,095,750	0	1,095,750	
K O Transmission Company	786,048	(10,680)	775,368	
ANR Pipeline Company	870,210	0	870,210	
PRODUCER/MARKETER (SCH. I - A)	531,019	0	531,019	
SYNTHETIC (SCH. I - A)				
OTHER GAS COMPANIES (SCH. I - B)				
OHIO PRODUCERS (SCH. I - B)				
SELF-HELP ARRANGEMENTS (SCH. I - B)		(1,720,006)	(1,720,006)	
SPECIAL PURCHASES (SCH. I - B)				
TOTAL DEMAND COSTS:	34,937,522	(1,854,028)	$33,083,494	
TOTAL GAS SALES LESS SPECIAL CONTRACT IT PURCHASES:			43,951,542	MCF
DEMAND (FIXED) COMPONENT OF EGC RATE:			$0.753	/MCF
COMMODITY COSTS:				
GAS MARKETERS			$3.343	/MCF
GAS STORAGE				
COLUMBIA GAS TRANSMISSION			$0.098	/MCF
TEXAS GAS TRANSMISSION			$0.028	/MCF
PROPANE			$0.000	/MCF
COMMODITY COMPONENT OF EGC RATE:			$3.469	/MCF
TOTAL EXPECTED GAS COST:			$4.222	/MCF

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Columbia Gas Transmission Corp. - Zone #3
TARIFF SHEET REFERENCE Second Revised Volume No. 1 Sheet No. 29/26
EFFECTIVE DATE OF TARIFF 2/1/2002 / 4/1/2002 RATE SCHEDULE NUMBER FSS/SST

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
CONTRACT DEMAND - FSS MDSQ	1.5110 *	2,646,168	3,998,360
CONTRACT DEMAND - FSS SCQ	0.0291 *	112,992,948	3,288,095
CONTRACT DEMAND - SST (Oct-Mar)	4.4769 *	1,323,084	5,923,315
CONTRACT DEMAND - SST (Apr-Sep)	4.4769 *	661,542	2,961,657
TOTAL DEMAND			16,171,427
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release - SST (System Sup)			(98,323)
TOTAL MISCELLANEOUS			(98,323)
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			16,073,104

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Rates
Applicable to Rate Schedule FSS, ISS, and SIT
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	General R&D Funding Unit 3/	Total Effective Rate	Daily Rate
Rate Schedule FSS										
Reservation Charge	$	1.511	-	-	-	-	-	-	1.511	0.050
Capacity	¢	2.91	-	-	-	-	-	-	2.91	2.91
Injection	¢	1.53	-	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	-	1.53	1.53
Overrun	¢	10.94	-	-	-	-	-	-	10.94	10.94
Rate Schedule ISS										
Commodity										
Maximum	¢	5.97	-	-	-	-	-	-	5.97	5.97
Minimum	¢	0.00	-	-	-	-	-	-	0.00	0.00
Injection	¢	1.53	-	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	-	1.53	1.53
Rate Schedule SIT										
Commodity										
Maximum	¢	4.14	-	-	-	-	-	-	4.14	4.14
Minimum	¢	1.53	-	-	-	-	-	-	1.53	1.53

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ GRI assessed where applicable pursuant to Section 154.401 of the Commission's Regulations.

Currently Effective Rates
Applicable to Rate Schedule SST and GTS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	General R&D Funding Unit 3/	Total Effective Rate	Daily Rate
Rate Schedule SST										
Reservation Charge 4/										
Maximum 1	$	5.754*	0.324	-0.018	0.030	-0.002	-	0.066	6.154	0.202
Maximum 2	$	5.754	0.324	-0.018	0.030	-0.002	-	0.041	6.129	0.201
Commodity										
Maximum	¢	1.02	0.11	-0.03	0.19	-0.01	0.21	0.55	2.04	2.04
Minimum	¢	1.02	0.11	0.00	0.19	0.00	0.21	0.00	1.53	1.53
Overrun	¢	19.94	1.18	-0.09	0.29	-0.02	0.21	0.55	22.06	22.06
Rate Schedule GTS										
Commodity										
Maximum	¢	76.02	2.24	-0.15	0.39	-0.02	0.21	0.88	79.57	79.57
Minimum	¢	3.08	0.11	0.00	0.19	0.00	0.21	0.00	3.59	3.59
MFCC	¢	72.94	2.13	-0.15	0.20	-0.02	-	-	75.10	75.10

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 30A.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ GRI assessed where applicable pursuant to Section 154.401 of the Commission's Regulations. The Maximum 1 rate is applicable to shippers with load factors exceeding 50%; Maximum 2 rate is applicable to shippers with load factors equal to or less than 50%.
4/ Minimum reservation charge is $0.00.

*LESS 28% DISCOUNT ON BASE RATE : 5.754 X .72 = 4.1429
PER RATE CASE #RP95-408 SETTLEMENT.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Union Light, Heat, and Power Company
TARIFF SHEET REFERENCE
EFFECTIVE DATE OF TARIFF 2/12/99 RATE SCHEDULE NUMBER

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
CONTRACT DEMAND	0.2998 *	2,160,000	647,568
TOTAL DEMAND			647,568
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			647,568

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Columbia Gulf Transmission Corp.
TARIFF SHEET REFERENCE Second Revised Volume No. 1 Sheet no. 18/18A
EFFECTIVE DATE OF TARIFF 4/1/2002 RATE SCHEDULE NUMBER FTS-1 / FTS-2

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FTS-1 DEMAND (NOV-MAR)	3.1450 *	566,070	1,780,290
FTS-1 DEMAND (APR-OCT)	3.1450 *	607,495	1,910,572
FTS-2 DEMAND (NOV-MAR)	0.9995 *	408,800	408,596
FTS-2 DEMAND (APR-OCT)	0.9995 *	438,718	438,499
TOTAL DEMAND			4,537,957
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
Capacity Release FTS-1			(24,492)
Capacity Release FTS-2			(527)
TOTAL MISCELLANEOUS			(25,019)
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			4,512,938

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Rates
Applicable to Rate Schedules FTS-1, ITS-1, FTS-2, and ITS-2
Rates per Dth

	Base Rate (1) $	Annual Charge Adjustment (2) $ 1/	Subtotal (3) $	General R&D Funding Unit (4) $ 2/	Total Effective Rate (5) $	Daily Rate (6) $	Company Use and Unaccounted For (7) %
Rate Schedule FTS-1							
Rayne, LA To Points North							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	3.1450	-	3.1450	0.0660	3.2110	0.1056	-
Load Factor Customers at or below 50%	3.1450	-	3.1450	0.0407	3.1857	0.1047	-
Commodity							
Maximum	0.0170	0.0021	0.0191	0.0055	0.0246	0.0246	2.346
Minimum	0.0170	0.0021	0.0191	0.0000	0.0191	0.0191	2.346
Overrun	0.1204	0.0021	0.1225	0.0055	0.1280	0.1280	2.346

Currently Effective Rates
Applicable to Rate Schedules FTS-1, ITS-1, FTS-2, and ITS-2
Rates per Dth

	Base Rate (1) $	Annual Charge Adjustment (2) $ 1/	Subtotal (3) $	General R&D Funding Unit (4) $ 2/	Total Effective Rate (5) $	Daily Rate (6) $	Company Use and Unaccounted For (7) %
Rate Schedule FTS-2							
Offshore Laterals							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	2.6700	-	2.6700	0.0660	2.7360	0.0900	-
Load Factor Customers at or below 50%	2.6700	-	2.6700	0.0407	2.7107	0.0891	-
Commodity							
Maximum	0.0002	0.0021	0.0023	0.0055	0.0078	0.0078	0.296
Minimum	0.0002	0.0021	0.0023	0.0000	0.0023	0.0023	0.296
Overrun	0.0880	0.0021	0.0901	0.0055	0.0956	0.0956	0.296
Onshore Laterals							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	1.0603	-	1.0603	0.0660	1.1263	0.0370	-
Load Factor Customers at or below 50%	1.0603	-	1.0603	0.0407	1.1010	0.0362	-
Commodity							
Maximum	0.0017	0.0021	0.0038	0.0055	0.0093	0.0093	0.388
Minimum	0.0017	0.0021	0.0038	0.0000	0.0038	0.0038	0.388
Overrun	0.0366	0.0021	0.0387	0.0055	0.0442	0.0442	0.388
Offsystem-Onshore							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	2.5255	-	2.5255	0.0660	2.5915	0.0852	-
Load Factor Customers at or below 50%	2.5255	-	2.5255	0.0407	2.5662	0.0844	-
Commodity							
Maximum	0.0070	0.0021	0.0091	0.0055	0.0146	0.0146	-
Minimum	0.0070	0.0021	0.0091	0.0000	0.0091	0.0091	-
Overrun	0.0900	0.0021	0.0921	0.0055	0.0976	0.0976	-

DISCOUNTED TO 0.9995 PER RATE CASE # RP97-52 SETTLEMENT.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Texas Gas Transmission Corp.
TARIFF SHEET REFERENCE First Revised Volume No. 1 Sheet no. 10
EFFECTIVE DATE OF TARIFF 1/1/2002 RATE SCHEDULE NUMBER NNS-4

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
CONTRACT DEMAND Nom&Unnom (Nov-Mar)	0.4700 *	14,571,500	6,848,605
CONTRACT DEMAND Nom&Unnom (April)	0.4700 *	993,960	467,161
CONTRACT DEMAND Nom (May-Sep)	0.4700 *	1,680,246	789,716
CONTRACT DEMAND Nom&Unnom (October)	0.4700 *	1,182,092	555,583
TOTAL DEMAND			8,661,065
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			8,661,065

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Maximum Transportation Rates ($ per MMBtu) For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	Sec. 33.3 Surcharge (2)	GRI [1] (3)	FERC ACA (4)	Currently Effective Rates (5)
Zone SL					
Daily Demand	0.1169		0.0022		0.1191
Commodity	0.0072		0.0055	0.0021	0.0148
Overrun	0.1241	0.0175	0.0055	0.0021	0.1492
Zone 1					
Daily Demand	0.3400		0.0022		0.3422
Commodity	0.0222		0.0055	0.0021	0.0298
Overrun	0.3622	0.0175	0.0055	0.0021	0.3873
Zone 2					
Daily Demand	0.3550		0.0022		0.3572
Commodity	0.0258		0.0055	0.0021	0.0334
Overrun	0.3808	0.0175	0.0055	0.0021	0.4059
Zone 3					
Daily Demand	0.4000		0.0022		0.4022
Commodity	0.0253		0.0055	0.0021	0.0329
Overrun	0.4253	0.0175	0.0055	0.0021	0.4504
Zone 4					
Daily Demand	0.4700		0.0022		0.4722
Commodity	0.0313		0.0055	0.0021	0.0389
Overrun	0.5013	0.0175	0.0055	0.0021	0.5264

Minimum Rate: Demand $-0-; NNS minimum commodity base rates equal applicable NNS maximum commodity base rates.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

[1] GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The NNS daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0013.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME: Texas Gas Transmission Corp.
TARIFF SHEET REFERENCE: First Revised Volume No. 1 Sheet no. 11
EFFECTIVE DATE OF TARIFF: 1/1/2002 RATE SCHEDULE NUMBER: FT

TYPE GAS PURCHASED: X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE: ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE: X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FT - DEMAND Direct Assignment (Zn SL)	0.3500 *	4,675,650	1,636,478
FT - DEMAND Direct Assignment (Zn 1)	0.3200 *	0	0
TOTAL DEMAND			1,636,478
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			1,636,478

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Maximum Daily Demand Rates ($ per MMBtu) For Service Under Rate Schedule FT

	Base Tariff Rates (1)	GRI {1} (2)	Currently Effective Rates (3)
SL-SL	0.0850	0.0022	0.0872
SL-1	0.1900	0.0022	0.1922
SL-2	0.2450	0.0022	0.2472
SL-3	0.2900	0.0022	0.2922
SL-4	0.3500	0.0022	0.3522
1-1	0.1600	0.0022	0.1622
1-2	0.2150	0.0022	0.2172
1-3	0.2600	0.0022	0.2622
1-4	0.3200	0.0022	0.3222
2-2	0.1500	0.0022	0.1522
2-3	0.1950	0.0022	0.1972
2-4	0.2550	0.0022	0.2572
3-3	0.1400	0.0022	0.1422
3-4	0.2050	0.0022	0.2072
4-4	0.1500	0.0022	0.1522

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

{1} GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The FT daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0013.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Tennessee Gas Pipeline Co.
TARIFF SHEET REFERENCE Fifth Revised Volume No. 1 Sheet no. 23
EFFECTIVE DATE OF TARIFF 1/1/2001 RATE SCHEDULE NUMBER FT

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FT - DEMAND (1-2)	4.87 *	225,000	1,095,750
TOTAL DEMAND			1,095,750
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			1,095,750

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Tennessee Gas Pipeline
an El Paso company

June 28, 2001

Cincinnati Gas & Electric Company
139 East Fourth Street
P.O. Box 960, Rm. 403A
Cincinnati, OH 45201

Attention: Tom Lawson

RE: Firm Transportation Discount
Tennessee FT-A Service Package No. 37338
Open Season # 274

Dear Tom:

In response to the request of Cincinnati Gas & Electric Company (CG&E), and pursuant to Section 5.1 of Tennessee Gas Pipeline's (Tennessee) FT-A Rate Schedule, Tennessee hereby agrees to adjust its then applicable FT-A Transportation rate for FT-A service provided under the above referenced contract as follows:

1. a) If CG&E, its assignee(s) or its agent(s) (hereinafter collectively referred to as "CG&E") violates the terms of this agreement or the terms of the above-referenced service package, Tennessee shall have the right, in its sole discretion, to immediately terminate this discount agreement and/or assess, from the date of the violation, the maximum Tennessee monthly reservation rate for the entire contract quantity and the maximum applicable commodity rates on all transactions occurring under this agreement.

   b) For the period commencing November 1, 2001, and extending through March 31, 2002, for gas delivered by Tennessee on behalf of CG&E to North Means (meter number 020049), the applicable FT-A rates for volumes received by Tennessee from Zone 1 receipt points not to exceed the MDQ of the zone, will be the lesser of:.

      i) A monthly reservation rate of $4.87 per Dth and a daily commodity rate of $0.0798 per Dth. These rates are inclusive of surcharges.

      or

      ii) Tennessee's applicable maximum FT-A reservation and commodity rates.

      In addition, CG&E will pay applicable fuel.

   c) Such discounted rates will be applicable only for a TQ of 45,000 Dth/day and for aggregate FT-A deliveries up to 45,000 Dth/day at the above specified delivery points for the time period specified above. Secondary receipts and/or secondary deliveries at points other than those listed above, as well as deliveries in excess of the TQ specified above, shall be assessed Tennessee's maximum applicable monthly reservation rate and the maximum applicable commodity rates under Rate Schedule FT-A.

Tennessee Gas Pipeline
1001 Louisiana Street Houston, Texas 77002
PO Box 2511 Houston, Texas 77252.2511
tel 713.420.2131

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME K O Transmission Company
TARIFF SHEET REFERENCE Original Volume No. 1 Sheet No. 10
EFFECTIVE DATE OF TARIFF 4/1/2002 RATE SCHEDULE NUMBER FTS

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FT - DEMAND	0.3560 *	2,208,000	786,048
TOTAL DEMAND			786,048
COMMODITY			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			(10,680)
TOTAL MISCELLANEOUS			(10,680)
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			775,368

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

CURRENTLY EFFECTIVE RATES
APPLICABLE TO RATE SCHEDULES FTS AND ITS

RATE LEVELS - RATE PER DTH

		Base Tariff Rate	Annual Charge Adjustment 1/	R&D Funding Unit 2/	Total Effective Rate
RATE SCHEDULE FTS					
Reservation Charge 3/					
	Maximum 1	$0.3560	--	$0.2180	$0.5740
	Maximum 2	$0.3560	--	$0.1340	$0.4900
Daily Rate - Maximum 1		$0.0117	--	$0.0072	$0.0189
Daily Rate - Maximum 2		$0.0117	--	$0.0044	$0.0161
Commodity					
	Maximum	$0.0000	$0.0021	$0.0085	$0.0106
	Minimum	$0.0000	$0.0021	$0.0000	$0.0021
Overrun		$0.0117	$0.0021	$0.0085	$0.0223
RATE SCHEDULE ITS					
Commodity					
	Maximum	$0.0117	$0.0021	$0.0085	$0.0223
	Minimum	$0.0000	$0.0021	$0.0000	$0.0021

1/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's regulations and will be charged pursuant to Section 23 of the General Terms and Conditions at such time that initial and successive annual ACA assessments applicable to Transporter are made.

2/ GRI assessed where applicable pursuant to Section 154.401 of the Commission's regulations. The Maximum 1 rate is applicable to customers with load factors exceeding 50%; the Maximum 2 is applicable to customers with load factors equal to or less than 50%.

3/ Minimum reservation charge is $0.00.

Transportation Retainage Adjustment 1.02%

NOTE: Utilizing GISB standards 5.3.22 and 5.3.23, Transporter's Rate Schedule FTS Reservation Charge can be converted to an applicable daily rate by dividing the above monthly rate by 30.4 days.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME: ANR Pipeline Company
TARIFF SHEET REFERENCE: Second Revised Volume No. 1 Sheets 7, 18, and 68G
EFFECTIVE DATE OF TARIFF: 2/1/1999 / 3/1/2002 / 11/1/1997 RATE SCHEDULE NUMBER: FTS - 1 /GATHERING

TYPE GAS PURCHASED: X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE: ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE: X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FTS-1 - DEMAND	8.4190 *	90,000	757,710
GATHERING - DEMAND	1.2500 *	90,000	112,500
TOTAL DEMAND			870,210
COMMODITY			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			870,210

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Previous Next Search

ANR Pipeline Company
FERC Gas Tariff
Second Revised Volume No. I

Ninth Revised Sheet No. 7
Superseding
Eighth Revised Sheet No. 7

RATE SCHEDULE FTS-1
MATRIX OF BASE TARIFF TRANSMISSION RATES PER DTH BY ROUTE
EXCLUSIVE OF ADDITIONAL CHARGES OR SURCHARGES

RECEIVED FROM \ DELIVERED TO		SOUTHEAST			SOUTHWEST			
		S.E. Area (SE)	Southern Segment (ML-2)	Central Segment (ML-3)	S.W. Area (SW)	Southern Segment (ML-5)	Central Segment (ML-6)	NORTHERN Segment (ML-7)
SOUTHEAST AREA (SE)	- Res	$1.7500	$6.5000	$8.2500	$14.7500	$12.7500	$11.2500	$9.7500
	- Cmd	0.0020	0.0105	0.0125	0.0225	0.0175	0.0160	0.0140
	- MIN	0.0020	0.0105	0.0125	0.0225	0.0175	0.0160	0.0140
	- Ovrn	0.0595	0.2242	0.2837	0.5074	0.4367	0.3859	0.3345
SE - Southern (ML-2)	- Res	$6.5000	$4.7500	$6.5000	$13.0000	$11.0000	$9.5000	$8.0000
	- Cmd	0.0105	0.0085	0.0105	0.0205	0.0155	0.0140	0.0120
	- MIN	0.0105	0.0085	0.0105	0.0205	0.0155	0.0140	0.0120
	- Ovrn	0.2242	0.1647	0.2242	0.4479	0.3771	0.3263	0.2750
SE - Central (ML-3)	- Res	$8.2500	$6.5000	$4.5000	$11.0000	$9.0000	$7.5000	$6.0000
	- Cmd	0.0125	0.0105	0.0080	0.0180	0.0130	0.0115	0.0095
	- MIN	0.0125	0.0105	0.0080	0.0180	0.0130	0.0115	0.0095
	- Ovrn	0.2837	0.2242	0.1559	0.3796	0.3089	0.2581	0.2068
SOUTHWEST AREA (SW)	- Res	$14.7500	$13.0000	$11.0000	$2.0000	$6.2500	$7.7500	$9.2500
	- Cmd	0.0225	0.0205	0.0180	0.0050	0.0125	0.0145	0.0160
	- MIN	0.0225	0.0205	0.0180	0.0050	0.0125	0.0145	0.0160
	- Ovrn	0.5074	0.4479	0.3796	0.0706	0.2180	0.2693	0.3201
SW - Southern (ML-5)	- Res	$12.7500	$11.0000	$9.0000	$6.2500	$4.2500	$5.7500	$7.2500
	- Cmd	0.0175	0.0155	0.0130	0.0125	0.0075	0.0095	0.0110
	- MIN	0.0175	0.0155	0.0130	0.0125	0.0075	0.0095	0.0110
	- Ovrn	0.4367	0.3771	0.3089	0.2180	0.1472	0.1985	0.2494
SW - Central (ML-6)	- Res	$11.2500	$9.5000	$7.5000	$7.7500	$5.7500	$4.2500	$5.7500
	- Cmd	0.0160	0.0140	0.0115	0.0145	0.0095	0.0080	0.0095
	- MIN	0.0160	0.0140	0.0115	0.0145	0.0095	0.0080	0.0095
	- Ovrn	0.3859	0.3263	0.2581	0.2693	0.1985	0.1477	0.1985
NORTHERN (ML-7)	- Res	$9.7500	$8.0000	$6.0000	$9.2500	$7.2500	$5.7500	$4.2500
	- Cmd	0.0140	0.0120	0.0095	0.0160	0.0110	0.0095	0.0075
	- MIN	0.0140	0.0120	0.0095	0.0160	0.0110	0.0095	0.0075
	- Ovrn	0.3345	0.2750	0.2068	0.3201	0.2494	0.1985	0.1472

General Notes:

All rates shown combine area and segment rates for each route, utilizing the transmission rates set forth on Sheet No. 12 and represent maximum rates unless designated as minimum firm service rates (MIN).

The rates shown are subject to all applicable reservation and volumetric charges or surcharges, under Sections 24 through 29 of the General Terms and Conditions. Sheet Nos. 17, 17A, and 18 reflect the applicable charges and surcharges under these Sections.

Issued by: W. L. Johnson, Senior Vice President
Issued on: December 17, 1998 Effective on: February 1, 1999

Previous Next Search

ANR Pipeline Company
FERC Gas Tariff
Second Revised Volume No. 1

Sixty-Second Revised Sheet No. 18
Superseding
Sixty-First Revised Sheet No. 18

STATEMENT OF SURCHARGES
(Continued)

General Terms and Conditions Section	Particulars	Maximum Rate per Dth Rate 1/	Short Haul Shippers 2/ SE 1/	SW 1/
28	Transition Cost Recovery Mechanisms 3/			
	GSR Reservation Surcharge Applicable to each Dth of MDQ for Rate Schedules ETS, STS, FTS-1, FTS-2 and FSS, if associated firm transportation service is not performed by Transporter.	$ 0.000	$ 0.000	$ 0.000
	PD Reservation Surcharge Applicable to each Dth of MDQ for Rate Schedules ETS, STS, FTS-1, FTS-2 and FSS, if associated transportation service is not performed by Transporter.	$ 0.000	$ 0.000	$ 0.000
	Dakota Reservation Surcharge Applicable to each Dth of MDQ for Rate Schedules ETS, STS, FTS-1, FTS-2 and FSS, if associated transportation service is not performed by Transporter.	$ 0.169	$ 0.030	$ 0.038
Other	Associated Liquids Charge applicable to ETS, FTS-1, FTS-2, STS and ITS service.	As stated as an Exhibit to the Agreement. 4/		

1 Minimum rate per Dth is $0.000.

2 The Short Haul Shipper charges are paid only by any Shipper that has all of its Primary Receipt and Delivery Point(s) located upstream of a Headstation, and delivers all of its Gas upstream of a Headstation. All other Shippers pay only the overall GSR Reservation Surcharge, the overall PD Reservation Surcharge and the overall Dakota Reservation Surcharge.

3 Transporter shall be entitled to submit a filing(s) under Section 4 of the Natural Gas Act and the Commission's Regulations to recover the costs, along with related carrying costs, of any portion of Transporter's facilities and assets no longer required or valued at historic levels as a result of the requirement of Transporter to unbundle gathering facilities from transmission pursuant to an order dated July 30, 1993 in Docket No. RS92-1-000.

4 Charges for Liquids transportation will be based on Article III of Appendix E of the Settlement Agreement in Docket Nos. RP79-39, RP80-100, RP81-61 and RP82-80, or such other charges as may from time to time be applicable.

Issued by: Jake Hiatt, Vice President
Issued on: February 28, 2002
Effective on: March 1, 2002

ANR Pipeline Company
FERC Gas Tariff
Second Revised Volume No. 1

Third Revised Sheet No. 68G
Superseding
Second Revised Sheet No. 68G

SOUTHEAST AREA GATHERING SERVICE

1. AVAILABILITY

This Southeast Area gathering service is available to any person, corporation, partnership or any other party (hereinafter referred to as "Shipper"). Terms and conditions applicable to this service will be individually negotiated between Shipper and Transporter, on a not unduly discriminatory basis, consistent with the terms and conditions applicable to Transporter's Part 284 transportation.

2. FIRM SERVICE CHARGES:

Each Month Shipper shall pay to Transporter a charge not to exceed the following:

2.1 Reservation Charge:

$1.250 for each Dekatherm of MDQ.

2.2 Commodity Charge:

$.0002 for each Dekatherm of Gas Delivered Hereunder.

3. INTERRUPTIBLE SERVICE CHARGES

Each Month Shipper shall pay to Transporter a commodity charge not to exceed $.0413 for each Dekatherm of Gas Delivered Hereunder.

Issued by: D. M. Ives, Vice President
Issued on: October 17, 1997

Effective on: November 1, 1997

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Various Producers / Marketers
TARIFF SHEET REFERENCE
EFFECTIVE DATE OF TARIFF RATE SCHEDULE NUMBER

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
Various Producers/Marketers	-	37,493,789	441,414
Needle Peaking @ City Gate (Various Suppliers)	-	1,077,500	89,605
TOTAL DEMAND			531,019
COMMODITY			
See Commodity Costs sheet, Page 10 of 10.			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
TOTAL MISCELLANEOUS			0
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			531,019

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER OR TRANSPORTER NAME Commodity Costs
TARIFF SHEET REFERENCE ____
EFFECTIVE DATE OF TARIFF ____ RATE SCHEDULE NUMBER ____

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF ___ OTHER
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

GAS COMMODITY RATE FOR SEPTEMBER, 2002 THROUGH NOVEMBER, 2002:

GAS MARKETERS :				
WEIGHTED AVERAGE GAS COST @ CITY GATE ($/Dth) (1):			$3.3351	$/Dth
CG&E FUEL	0.900%	$0.0300	$3.3651	$/Dth
DTH TO MCF CONVERSION	1.0263	$0.0885	$3.4536	$/Mcf
ESTIMATED WEIGHTING FACTOR	0.9680		$3.3431	$/Mcf
GAS MARKETERS COMMODITY RATE			**$3.343**	**$/Mcf**
GAS STORAGE :				
COLUMBIA GAS TRANS. - STORAGE INVENTORY RATE			$3.6605	$/Dth
COLUMBIA GAS TRANS. FSS WITHDRAWAL FEE		$0.0153	$3.6758	$/Dth
COLUMBIA GAS TRANS. SST FUEL	2.398%	$0.0881	$3.7639	$/Dth
COLUMBIA GAS TRANS SST COMMODITY RATE		$0.0128	$3.7767	$/Dth
KO TRANS, COMMODITY RATE		$0.0138	$3.7905	$/Dth
CG&E FUEL	0.900%	$0.0341	$3.8246	$/Dth
DTH TO MCF CONVERSION	1.0263	$0.1006	$3.9252	$/Mcf
ESTIMATED WEIGHTING FACTOR	0.0250		$0.0981	$/Mcf
GAS STORAGE COMMODITY RATE - COLUMBIA GAS			**$0.098**	**$/Mcf**
EXAS GAS TRANSMISSION - STORAGE INVENTORY RATE			$3.7686	$/Dth
TEXAS GAS COMMODITY RATE		$0.0334	$3.8020	$/Dth
CG&E FUEL	0.900%	$0.0342	$3.8362	$/Dth
DTH TO MCF CONVERSION	1.0263	$0.1009	$3.9371	$/Mcf
ESTIMATED WEIGHTING FACTOR	0.0070		$0.0276	$/Mcf
GAS STORAGE COMMODITY RATE - TEXAS GAS			**$0.028**	**$/Mcf**
PROPANE :				
WEIGHTED AVERAGE PROPANE INVENTORY RATE			$0.40416	$/Gal
GALLON TO MCF CONVERSION	14.84	$5.5936	$5.9978	$/Mcf
ESTIMATED WEIGHTING FACTOR	0.0000		$0.0000	$/Mcf
PROPANE COMMODITY RATE			**$0.000**	**$/Mcf**

FOOTNOTE NO. (1) Weighted average cost of gas based on NYMEX prices on 7/24/02 and contracted hedging prices.

PURCHASED GAS ADJUSTMENT

SCHEDULE I - B
PAGE 1 OF 1

OTHER PRIMARY GAS SUPPLIERS

DETAILS FOR THE EGC IN EFFECT AS OF SEPTEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED MAY 31, 2002

SUPPLIER NAME	UNIT RATE	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT
OTHER GAS COMPANIES			
TOTAL OTHER GAS COMPANIES			-
OHIO PRODUCERS			
TOTAL OHIO PRODUCERS			-
SELF-HELP ARRANGEMENT			
TRANSPORTATION			
OTHER MISCELLANEOUS (SPECIFY)			
Firm Balancing Service (FBS) Credit (1)	0.181 *	9,083,111	(1,644,043)
Contract Commitment Cost Recovery (CCCR) Credit (1)	0.001 *	53,034,653	(75,963)
TOTAL SELF-HELP ARRANGEMENT			(1,720,006)
SPECIAL PURCHASES			

FOOTNOTE NO. (1) Unit rate and volumes are in $/Mcf and Mcf respectively.

PURCHASED GAS ADJUSTMENT
CINCINNATI GAS & ELECTRIC CO.
ATTACHMENT TO SCHEDULE I

INCLUDABLE PROPANE (PEAK SHAVING @ EASTERN AVE. AND DICKS CREEK PLANTS) :			
BOOK COST OF INCLUDABLE PROPANE ($/GAL)			0.41544
INCLUDABLE PROPANE FOR 12 MO. ENDED	MAY 31, 2002	(GALS)	63,764
		SUB TOTAL	26,490
INCLUDABLE PROPANE (PEAK SHAVING @ ERLANGER PLANT) :			
BOOK COST OF INCLUDABLE PROPANE ($/GAL)			0.34268
INCLUDABLE PROPANE FOR 12 MO. ENDED	MAY 31, 2002	(GALS)	11,697
		SUB TOTAL	4,008
		TOTAL DOLLARS	$30,498
		TOTAL GALLONS	75,461
See Commodity Costs sheet, Page 10 of 10.		WEIGHTED AVERAGE RATE	$0.40416

PURCHASE GAS ADJUSTMENT
THE CINCINNATI GAS & ELECTRIC COMPANY
SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT
DETAILS FOR THE THREE MONTH PERIOD ENDED MAY 31, 2002

PARTICULARS			UNIT	AMOUNT
JURISDICTIONAL SALES: TWELVE MONTHS ENDED	MAY 31,	2002	MCF	43,951,542
TOTAL SALES: TWELVE MONTHS ENDED	MAY 31,	2002	MCF	43,951,542
RATIO OF JURISDICTIONAL SALES TO TOTAL SALES			RATIO	1.000
SUPPLIER REFUNDS RECEIVED AND RECONCILIATION ADJUSTMENTS ORDERED DURING THE THREE MONTH PERIOD	MAY 31,	2002	$	(167,988.00)
JURISDICTIONAL SHARE OF SUPPLIER REFUNDS AND RECONCILIATION ADJUSTMENTS			$	(167,988.00)
INTEREST FACTOR				1.0550
JURISDICTIONAL SHARE OF SUPPLIER REFUNDS AND RECONCILIATION ADJUSTMENTS, INCLUDING INTEREST			$	(177,227.34)
JURISDICTIONAL SALES: TWELVE MONTHS ENDED	MAY 31,	2002	MCF	43,951,542
CURRENT SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT			$/MCF	(0.004)

DETAILS OF REFUNDS / ADJUSTMENTS
RECEIVED DURING THE THREE MONTH PERIOD ENDED MAY 31, 2002

PARTICULARS (SPECIFY)	UNIT	AMOUNT
SUPPLIER		
COLUMBIA GAS TRANSMISSION COMPANY - REFUND DATED APRIL 19, 2002	$	167,988.00
TOTAL REFUNDS APPLICABLE TO THE CURRENT GCR	$	167,988.00

RA

SCHEDULE III

PURCHASE GAS ADJUSTMENT
THE CINCINNATI GAS & ELECTRIC COMPANY
ACTUAL ADJUSTMENT
DETAILS FOR THE THREE MONTH PERIOD ENDED MAY 31, 2002

PARTICULARS	UNIT	MARCH	APRIL	MAY
SUPPLY VOLUME PER BOOKS				
PRIMARY GAS SUPPLIERS	MCF	6,112,329	2,465,208	1,891,355
UTILITY PRODUCTION	MCF	0	0	0
INCLUDABLE PROPANE	MCF	3,430	0	0
OTHER VOLUMES (SPECIFY) ADJUSTMENT	MCF	(66,111)	(12,928)	(36,646)
TOTAL SUPPLY VOLUMES	MCF	6,049,648	2,452,280	1,854,709
SUPPLY COST PER BOOKS				
PRIMARY GAS SUPPLIERS	$	24,488,234	10,259,943	8,088,482
TRANSITION COSTS	$	0	0	0
UTILITY PRODUCTION	$	0	0	0
INCLUDABLE PROPANE	$	16,462	0	0
OTHER COSTS (SPECIFY):				
MIRANT MANAGEMENT FEE	$	0	(149,134)	(149,134)
CONTRACT COMMITTMENT COSTS RIDER	$	(32,938)	(23,023)	(10,933)
TRANSPORTATION GAS COST CREDIT	$	0	0	0
RATE "IT" CREDIT	$	0	0	0
FIRM TRANSPORTATION SUPPLIER COST	$	5,093	3,332	1,381
CUSTOMER POOL USAGE COST	$	(312,847)	(351,048)	(250,754)
LOSSES - DAMAGED LINES	$	0	(1,195)	(9,698)
SALES TO REMARKETERS	$	0	0	0
WEIGHTED AVERAGE PIPELINE COST REFUNDED/(BILLED) TO SUPPLIERS	$	0	0	0
TOTAL SUPPLY COSTS	$	24,164,004	9,738,875	7,669,344
SALES VOLUMES				
JURISDICTIONAL	MCF	6,583,512.7	4,553,195.0	2,084,603.3
NON-JURISDICTIONAL	MCF	0.0	0.0	0.0
OTHER VOLUMES (SPECIFY):	MCF	0.0	0.0	0.0
TOTAL SALES VOLUMES	MCF	6,583,512.7	4,553,195.0	2,084,603.3
UNIT BOOK COST OF GAS (SUPPLY $ / SALES MCF)	$/MCF	3.670	2.139	3.679
LESS: EGC IN EFFECT FOR THE MONTH	$/MCF	3.460	3.455	3.466
DIFFERENCE	$/MCF	0.210	(1.316)	0.213
TIMES: MONTHLY JURISDICTIONAL SALES	MCF	6,583,512.7	4,553,195.0	2,084,603.3
EQUALS MONTHLY COST DIFFERENCE	$	1,382,537.67	(5,992,004.62)	444,020.50

PARTICULARS	UNIT	AMOUNT
TOTAL GAS COST DIFFERENCE FOR THE THREE MONTH PERIOD	$	(4,165,446.45)
MIRANT MANAGEMENT FEE CREDIT FOR THE QUARTER (SEE NOTE)	$	(149,135.00)
TOTAL COST USED IN THE CURRENT AA CALCULATION	$	(4,314,581.45)
DIVIDED BY: TWELVE MONTH SALES ENDED MAY 31, 2002	MCF	43,951,542
EQUALS CURRENT QUARTERLY ACTUAL ADJUSTMENT	$/MCF	(0.098)

Note: The Mirant Management Fee for March, 2002 was credited directly to the deferral. Then, starting in April a decision was made to credit this amount to the purchase gas expenses and reflect the amount as a credit in the calculation of the current month deferral.

SCHEDULE IV

PURCHASE GAS ADJUSTMENT
THE CINCINNATI GAS & ELECTRIC COMPANY
BALANCE ADJUSTMENT
DETAILS FOR THE THREE MONTH PERIOD ENDED MAY 31, 2002

PARTICULARS	UNIT	AMOUNT
COST DIFFERENCE BETWEEN BOOK AND EFFECTIVE EGC AS USED TO COMPUTE AA OF THE GCR IN EFFECT FOUR QUARTERS PRIOR TO THE CURRENTLY EFFECTIVE GCR (JUNE 1, 2001)	$	9,628,840.26
LESS: DOLLAR AMOUNT RESULTING FROM THE AA OF $ 0.199 /MCF AS USED TO COMPUTE THE GCR IN EFFECT FOUR QUARTERS PRIOR TO THE CURRENTLY EFFECTIVE GCR TIMES THE JURISDICTIONAL SALES OF 45,646,545 MCF FOR THE PERIOD BETWEEN THE EFFECTIVE DATE OF THE CURRENT GCR RATE AND THE EFFECTIVE DATE OF THE GCR IN EFFECT APPROXIMATELY ONE YEAR PRIOR TO THE CURRENT RATE	$	9,083,662.52
BALANCE ADJUSTMENT FOR THE AA	$	545,177.74
DOLLAR AMOUNT OF SUPPLIER REFUNDS AND COMMISSION ORDERED RECONCILIATION ADJUSTMENTS AS USED TO COMPUTE RA OF THE GCR IN EFFECT FOUR QUARTERS PRIOR TO THE CURRENTLY EFFECTIVE GCR (JUNE 1, 2001)	$	(29,793.24)
LESS: DOLLAR AMOUNT RESULTING FROM THE UNIT RATE FOR SUPPLIER REFUNDS AND RECONCILIATION ADJUSTMENTS OF $ (0.001) /MCF AS USED TO COMPUTE RA OF THE GCR IN EFFECT FOUR QUARTERS PRIOR TO THE CURRENTLY EFFECTIVE GCR TIMES THE JURISDICTIONAL SALES OF 45,646,545 MCF FOR THE PERIOD BETWEEN THE EFFECTIVE DATE OF THE CURRENT GCR RATE AND THE EFFECTIVE DATE OF THE GCR RATE IN EFFECT APPROXIMATELY ONE YEAR PRIOR TO THE CURRENT RATE	$	(45,646.55)
BALANCE ADJUSTMENT FOR THE RA	$	15,853.31
LLAR AMOUNT OF THE BALANCE ADJUSTMENT AS USED TO COMPUTE BA OF THE CR IN EFFECT ONE QUARTER PRIOR TO THE CURRENTLY EFFECTIVE GCR (MARCH 1, 2002)	$	221,780.90
LESS: DOLLAR AMOUNT RESULTING FROM THE BA OF $ 0.016 /MCF AS USED TO COMPUTE THE GCR IN EFFECT ONE QUARTER PRIOR TO THE CURRENTLY EFFECTIVE GCR TIMES THE JURISDICTIONAL SALES OF 14,225,663 MCF FOR THE PERIOD BETWEEN THE EFFECTIVE DATE OF THE CURRENT GCR RATE AND THE EFFECTIVE DATE OF THE GCR RATE IN EFFECT IMMEDIATELY PRIOR TO THE CURRENT RATE	$	227,610.60
BALANCE ADJUSTMENT FOR THE BA	$	(5,829.70)
TOTAL BALANCE ADJUSTMENT AMOUNT	$	555,201.35

BA

SCHEDULE V

PURCHASE GAS ADJUSTMENT
THE CINCINNATI GAS & ELECTRIC COMPANY

TRANSPORTATION SERVICE TAKE-OR-PAY
RECOVERY RATE CALCULATION
FOR THE QUARTER BEGINNINGSEPTEMBER 1, 2002

PARTICULARS			UNIT	AMOUNT
ESTIMATED TAKE-OR-PAY COSTS BASED ON TWELVE MONTHS ENDED	MAY 31,	2002		
COLUMBIA GAS TRANSMISSION CORPORATION			$	0.00
TEXAS GAS TRANSMISSION CORPORATION			$	0.00
CNG TRANSMISSION CORPORATION			$	0.00
TOTAL ESTIMATED TAKE-OR-PAY COSTS			$	0.00
TIMES 13% ALLOCATED TO TRANSPORTATION SERVICE			$	0.00
DIVIDED BY TRANSPORTATION VOLUMES FOR TWELVE MONTHS ENDED	MAY 31,	2002	MCF	29,605,048
EQUALS: CURRENT QUARTER TOP FACTOR			$/MCF	0.000
TOP REFUNDS RECEIVED DURING THE QUARTER ENDED MAY 31, 2002 FOR REFUNDING DURING THE TWELVE MONTHS SEPTEMBER 1, 2002 THROUGH AUGUST 31, 2003			$	0.00
TIMES 13% ALLOCATED TO TRANSPORTATION SERVICE			$	0.00
DIVIDED BY TRANSPORTATION VOLUMES FOR TWELVE MONTHS ENDED	MAY 31,	2002	MCF	29,605,048
ꞯUALS: CURRENT QUARTER TOP FACTOR			$/MCF	0.000
PLUS PRIOR QUARTER TRANSPORTATION TOP REFUND RATE EFFECTIVE FOR TWELVE MONTHS JUNE 1, 2002 THROUGH MAY 31, 2003			$/MCF	0.000
PLUS SECOND PRIOR QUARTER TRANSPORTATION TOP REFUND RATE EFFECTIVE FOR TWELVE MONTHS MARCH 1, 2002 THROUGH FEBRUARY 28, 2003			$/MCF	0.000
PLUS THIRD PRIOR QUARTER TRANSPORTATION TOP REFUND RATE EFFECTIVE FOR TWELVE MONTHS DECEMBER 1, 2001 THROUGH NOVEMBER 30, 2002			$/MCF	0.000
TOTAL TRANSPORTATION TOP RECOVERY RATE			$/MCF	0.000

TOP

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

GAS COST RECOVERY RATE CALCULATIONS

PARTICULARS	UNIT	AMOUNT
EXPECTED GAS COST (EGC)	$/MCF	5.059
SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT (RA)	$/MCF	(0.064)
ACTUAL ADJUSTMENT (AA)	$/MCF	(0.209)
BALANCE ADJUSTMENT (BA)	$/MCF	(0.228)
GAS COST RECOVERY RATE (GCR) = EGC + RA + AA +BA	$/MCF	4.558

GAS COST RECOVERY RATE EFFECTIVE DATES: NOVEMBER 28, 2002 THROUGH FEBRUARY 28, 2003

EXPECTED GAS COST CALCULATION

DESCRIPTION	UNIT	AMOUNT
TOTAL EXPECTED GAS COST COMPONENT (EGC)	$/MCF	5.059

SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
CURRENT QUARTERLY SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	(0.060)
PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	(0.004)
SECOND PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	0.000
THIRD PREVIOUS QUARTERLY REPORTED SUPPLIER REFUND & RECONCILIATION ADJUSTMENT	$/MCF	0.000
SUPPLIER REFUND AND RECONCILIATION ADJUSTMENT (RA)	$/MCF	(0.064)

ACTUAL ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
RRENT QUARTERLY ACTUAL ADJUSTMENT	$/MCF	(0.029)
PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	(0.098)
SECOND PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	(0.269)
THIRD PREVIOUS QUARTERLY REPORTED ACTUAL ADJUSTMENT	$/MCF	0.187
ACTUAL ADJUSTMENT (AA)	$/MCF	(0.209)

BALANCE ADJUSTMENT SUMMARY CALCULATION

PARTICULARS	UNIT	AMOUNT
BALANCE ADJUSTMENT AMOUNT	$	(4,809,170.09)
JURISDICTIONAL SALES FOR THE QUARTER	MCF	21,100,522
BALANCE ADJUSTMENT (BA)	$/MCF	(0.228)

THIS QUARTERLY REPORT FILED PURSUANT TO ORDER NO. 76-515-GA-ORD
OF THE PUBLIC UTILITIES COMMISSION OF OHIO, DATED OCTOBER 18, 1979.

DATE FILED: October 30, 2002

BY: JOHN P. STEFFEN

TITLE: VICE-PRESIDENT, RATES

PURCHASED GAS ADJUSTMENT

SCHEDULE I

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

EXPECTED GAS COST RATE CALCULATION

DETAILS FOR THE EGC RATE IN EFFECT AS OF DECEMBER 1, 2002
VOLUME FOR THE TWELVE MONTH PERIOD ENDED AUGUST 31, 2002

DEMAND COSTS	DEMAND EXPECTED GAS COST AMT ($)	MISC EXPECTED GAS COST AMT ($)	TOTAL DEMAND EXPECTED GAS COST AMT ($)	
INTERSTATE PIPELINE SUPPLIERS (SCH. I-A)				
Columbia Gas Transmission Corp.	16,171,427	0	16,171,427	
Union Light, Heat, and Power Co.	647,568	0	647,568	
Columbia Gulf Transmission Co.	4,537,957	0	4,537,957	
Texas Gas Transmission Corp.	9,667,707	0	9,667,707	
Tennessee Gas Pipeline	491,250	0	491,250	
K O Transmission Company	786,048	0	786,048	
PRODUCER/MARKETER (SCH. I - A)	534,230	0	534,230	
SYNTHETIC (SCH. I - A)				
OTHER GAS COMPANIES (SCH. I - B)				
OHIO PRODUCERS (SCH. I - B)				
SELF-HELP ARRANGEMENTS (SCH. I - B)		(1,856,977)	(1,856,977)	
SPECIAL PURCHASES (SCH. I - B)				
TOTAL DEMAND COSTS:	32,836,187	(1,856,977)	$30,979,210	
TOTAL GAS SALES LESS SPECIAL CONTRACT IT PURCHASES:			43,270,532	MCF
DEMAND (FIXED) COMPONENT OF EGC RATE:			**$0.716**	**/MCF**
COMMODITY COSTS:				
GAS MARKETERS			$3.062	/MCF
GAS STORAGE				
COLUMBIA GAS TRANSMISSION			$1.046	/MCF
TEXAS GAS TRANSMISSION			$0.223	/MCF
PROPANE			$0.012	/MCF
COMMODITY COMPONENT OF EGC RATE:			**$4.343**	**/MCF**
TOTAL EXPECTED GAS COST:			**$5.059**	**/MCF**

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF DECEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED AUGUST 31, 2002

SUPPLIER OR TRANSPORTER NAME Columbia Gas Transmission Corp. - Zone #3
TARIFF SHEET REFERENCE Second Revised Volume No. 1 Sheet No. 29/26
EFFECTIVE DATE OF TARIFF 2/1/2002 / 4/1/2002 RATE SCHEDULE NUMBER FSS/SST

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)		TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND				
CONTRACT DEMAND - FSS MDSQ	1.5110	*	2,646,168	3,998,360
CONTRACT DEMAND - FSS SCQ	0.0291	*	112,992,948	3,288,095
CONTRACT DEMAND - SST (Oct-Mar)	4.4769	*	1,323,084	5,923,315
CONTRACT DEMAND - SST (Apr-Sep)	4.4769	*	661,542	2,961,657
TOTAL DEMAND				16,171,427
COMMODITY				
COMMODITY				
OTHER COMMODITY (SPECIFY)				
TOTAL COMMODITY				-
MISCELLANEOUS				
TRANSPORTATION	-		-	-
OTHER MISCELLANEOUS (SPECIFY)	-		-	-
Capacity Release - SST (System Sup)				-
TOTAL MISCELLANEOUS				-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER				16,171,427

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Rates
Applicable to Rate Schedule FSS, ISS, and SIT
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	General R&D Funding Unit 3/	Total Effective Rate	Daily Rate
Rate Schedule FSS										
Reservation Charge	$	1.511	-	-	-	-	-	-	1.511	0.050
Capacity	¢	2.91	-	-	-	-	-	-	2.91	2.91
Injection	¢	1.53	-	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	-	1.53	1.53
Overrun	¢	10.94	-	-	-	-	-	-	10.94	10.94
Rate Schedule ISS										
Commodity										
Maximum	¢	5.97	-	-	-	-	-	-	5.97	5.97
Minimum	¢	0.00	-	-	-	-	-	-	0.00	0.00
Injection	¢	1.53	-	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	-	1.53	1.53
Rate Schedule SIT										
Commodity										
Maximum	¢	4.14	-	-	-	-	-	-	4.14	4.14
Minimum	¢	1.53	-	-	-	-	-	-	1.53	1.53

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ GRI assessed where applicable pursuant to Section 154.401 of the Commission's Regulations.

Currently Effective Rates
Applicable to Rate Schedule SST and GTS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment Current	Transportation Cost Rate Adjustment Surcharge	Electric Power Costs Adjustment Current	Electric Power Costs Adjustment Surcharge	Annual Charge Adjustment 2/	General R&D Funding Unit 3/	Total Effective Rate	Daily Rate
Rate Schedule SST										
Reservation Charge 4/		*								
Maximum 1	$	5.754	0.324	-0.018	0.030	-0.002	-	0.066	6.154	0.202
Maximum 2	$	5.754	0.324	-0.018	0.030	-0.002	-	0.041	6.129	0.201
Commodity										
Maximum	¢	1.02	0.11	-0.03	0.19	-0.01	0.21	0.55	2.04	2.04
Minimum	¢	1.02	0.11	0.00	0.19	0.00	0.21	0.00	1.53	1.53
Overrun	¢	19.94	1.18	-0.09	0.29	-0.02	0.21	0.55	22.06	22.06
Rate Schedule GTS										
Commodity										
Maximum	¢	76.02	2.24	-0.15	0.39	-0.02	0.21	0.88	79.57	79.57
Minimum	¢	3.08	0.11	0.00	0.19	0.00	0.21	0.00	3.59	3.59
MFCC	¢	72.94	2.13	-0.15	0.20	-0.02	-	-	75.10	75.10

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 30A.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ GRI assessed where applicable pursuant to Section 154.401 of the Commission's Regulations. The Maximum 1 rate is applicable to shippers with load factors exceeding 50%; Maximum 2 rate is applicable to shippers with load factors equal to or less than 50%.
4/ Minimum reservation charge is $0.00.

* LESS 28% DISCOUNT ON BASE RATE: 5.754 X .72 = 4.1429
PER RATE CASE # RP95-408 SETTLEMENT.

Issued by: Carl W. Levander, Vice President
Issued on: March 1, 2002

Effective: April 1, 2002

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF DECEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED AUGUST 31, 2002

SUPPLIER OR TRANSPORTER NAME Union Light, Heat, and Power Company
TARIFF SHEET REFERENCE
EFFECTIVE DATE OF TARIFF 2/12/99 RATE SCHEDULE NUMBER

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
CONTRACT DEMAND	0.2998 *	2,160,000	647,568
TOTAL DEMAND			647,568
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			647,568

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

PURCHASED GAS ADJUSTMENT

SCHEDULE I - A
PAGE 3 OF 9

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF DECEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED AUGUST 31, 2002

SUPPLIER OR TRANSPORTER NAME Columbia Gulf Transmission Corp.
TARIFF SHEET REFERENCE Second Revised Volume No. 1 Sheet no. 18/18A
EFFECTIVE DATE OF TARIFF 4/1/2002 RATE SCHEDULE NUMBER FTS-1 / FTS-2

TYPE GAS PURCHASED X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
FTS-1 DEMAND (NOV-MAR)	3.1450 *	566,070	1,780,290
FTS-1 DEMAND (APR-OCT)	3.1450 *	607,495	1,910,572
FTS-2 DEMAND (NOV-MAR)	0.9995 *	408,800	408,596
FTS-2 DEMAND (APR-OCT)	0.9995 *	438,718	438,499
TOTAL DEMAND			4,537,957
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			0
MISCELLANEOUS			
TRANSPORTATION	-	-	-
Capacity Release FTS-1			-
Capacity Release FTS-2			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			4,537,957

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Currently Effective Rates
Applicable to Rate Schedules FTS-1, ITS-1, FTS-2, and ITS-2
Rates per Dth

	Base Rate (1) $	Annual Charge Adjustment (2) $ 1/	Subtotal (3) $	General R&D Funding Unit (4) $ 2/	Total Effective Rate (5) $	Daily Rate (6) $	Company Use and Unaccounted For (7) %
Rate Schedule FTS-1							
Rayne, LA To Points North							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	3.1450	-	3.1450	0.0660	3.2110	0.1056	-
Load Factor Customers at or below 50%	3.1450	-	3.1450	0.0407	3.1857	0.1047	-
Commodity							
Maximum	0.0170	0.0021	0.0191	0.0055	0.0246	0.0246	2.346
Minimum	0.0170	0.0021	0.0191	0.0000	0.0191	0.0191	2.346
Overrun	0.1204	0.0021	0.1225	0.0055	0.1280	0.1280	2.346

Issued by: Carl W. Levander, Vice President
Issued on: March 1, 2002

Effective: April 1, 2002

Currently Effective Rates
Applicable to Rate Schedules FTS-1, ITS-1, FTS-2, and ITS-2
Rates per Dth

	Base Rate (1) $	Annual Charge Adjustment (2) $ 1/	Subtotal (3) $	General R&D Funding Unit (4) $ 2/	Total Effective Rate (5) $	Daily Rate (6) $	Company Use and Unaccounted For (7) %
Rate Schedule FTS-2							
Offshore Laterals							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	2.6700	-	2.6700	0.0660	2.7360	0.0900	-
Load Factor Customers at or below 50%	2.6700	-	2.6700	0.0407	2.7107	0.0891	-
Commodity							
Maximum	0.0002	0.0021	0.0023	0.0055	0.0078	0.0078	0.296
Minimum	0.0002	0.0021	0.0023	0.0000	0.0023	0.0023	0.296
Overrun	0.0880	0.0021	0.0901	0.0055	0.0956	0.0956	0.296
Onshore Laterals							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	1.0603	-	1.0603	0.0660	1.1263	0.0370	-
Load Factor Customers at or below 50%	1.0603	-	1.0603	0.0407	1.1010	0.0362	-
Commodity							
Maximum	0.0017	0.0021	0.0038	0.0055	0.0093	0.0093	0.388
Minimum	0.0017	0.0021	0.0038	0.0000	0.0038	0.0038	0.388
Overrun	0.0366	0.0021	0.0387	0.0055	0.0442	0.0442	0.388
Offsystem-Onshore							
Reservation Charge 3/							
Maximum							
Load Factor Customers above 50%	2.5255	-	2.5255	0.0660	2.5915	0.0852	-
Load Factor Customers at or below 50%	2.5255	-	2.5255	0.0407	2.5662	0.0844	-
Commodity							
Maximum	0.0070	0.0021	0.0091	0.0055	0.0146	0.0146	-
Minimum	0.0070	0.0021	0.0091	0.0000	0.0091	0.0091	-
Overrun	0.0900	0.0021	0.0921	0.0055	0.0976	0.0976	-

DISCOUNTED TO 0.9995 PER RATE CASE #RP97-52 SETTLEMENT.

PURCHASED GAS ADJUSTMENT

COMPANY NAME: THE CINCINNATI GAS & ELECTRIC COMPANY

PRIMARY GAS SUPPLIER / TRANSPORTER

DETAILS FOR THE EGC IN EFFECT AS OF DECEMBER 1, 2002 AND THE
VOLUME FOR THE TWELVE MONTH PERIOD ENDED AUGUST 31, 2002

SUPPLIER OR TRANSPORTER NAME: Texas Gas Transmission Corp.
TARIFF SHEET REFERENCE: First Revised Volume No. 1 Sheet no. 10
EFFECTIVE DATE OF TARIFF: 8/1/2002 RATE SCHEDULE NUMBER: NNS-4

TYPE GAS PURCHASED: X NATURAL ___ LIQUIFIED ___ SYNTHETIC
UNIT OR VOLUME TYPE: ___ MCF ___ CCF X OTHER DTH
PURCHASE SOURCE: X INTERSTATE ___ INTRASTATE

INCLUDABLE GAS SUPPLIERS

PARTICULARS	UNIT RATE ($ PER)	TWELVE MONTH VOLUME	EXPECTED GAS COST AMOUNT ($)
DEMAND			
CONTRACT DEMAND Nom&Unnom (Nov-Mar)	0.4125 *	13,590,000	5,605,875
CONTRACT DEMAND Nom&Unnom (April)	0.4125 *	974,460	401,965
CONTRACT DEMAND Nom (May-Sep)	0.4125 *	1,680,246	693,101
CONTRACT DEMAND Nom&Unnom (October)	0.4125 *	1,161,942	479,301
TOTAL DEMAND			7,180,242
COMMODITY			
COMMODITY			
OTHER COMMODITY (SPECIFY)			
TOTAL COMMODITY			-
MISCELLANEOUS			
TRANSPORTATION	-	-	-
OTHER MISCELLANEOUS (SPECIFY)	-	-	-
Capacity Release			-
TOTAL MISCELLANEOUS			-
TOTAL EXPECTED GAS COST OF PRIMARY SUPPLIER/TRANSPORTER			7,180,242

NOTE: IF ANY RATE SHOWN ABOVE IS DIFFERENT THAN THE UNIT RATE REPORTED IN PREVIOUS QUARTERLY REPORT, INDICATE WITH AN ASTERISK (*) AND ATTACH COPY OF SUPPLIER TARIFF SHEET. IF TARIFF SHEET IS NOT AVAILABLE, THEN PROVIDE A DETAILED EXPLANATION.

Williams.

GAS PIPELINE
SouthCentral
P.O. Box 20008
3800 Frederica St.
Owensboro, Kentucky 42304
270/926-8686

August 1, 2002

Mr. Jim Henning
The Cincinnati Gas and Electric Company
139 East Fourth Street
Cincinnati, OH 45202

RE: Revised Discount Agreement

Dear Jeff:

Texas Gas Transmission Corporation (Texas Gas) has reviewed The Cincinnati Gas and Electric Company's (CG&E) request for a discounted transportation rate for the time period listed below. Accordingly, Texas Gas is willing to offer CG&E the following discount:

Contract No.	N000405
Rate Schedule:	NNS
Time Period:	November 1, 2002 through October 31, 2004
Delivery Point:	Cincinnati Gas and Electric Company, Meter No. 1229
Discounted Demand Rate:	For each unit of its daily contract demand, CG&E shall pay $0.4125 (including all surcharges).
Discounted Commodity Rate:	Texas Gas shall discount the GRI surcharge on all volumes delivered to CG&E's city gate meter. In addition to the the GRI discount, Texas Gas shall agree to discount its maximum NNS commodity rate by one cent ($0.01) on all volumes delivered to CG&E's city gate meter.
Delivery Point Qualification:	The Discounted Demand Rate and Discounted Commodity Rate are limited to quantities delivered at the Delivery Point specified above. **TO THE EXTENT THAT CG&E OR ITS REPLACEMENT SHIPPER(S) DELIVER GAS TO AN ALTERNATE DELIVERY POINT ON ANY DAY, THEN THE DISCOUNTED DEMAND RATE AND THE DISCOUNTED COMMODITY RATE PROVIDED ABOVE SHALL NOT APPLY TO AN EQUIVALENT PORTION OF CG&E'S CONTRACT DEMAND. IN SUCH CASE, CG&E SHALL PAY THE MAXIMUM ZONE 4 RESERVATION RATE PLUS THE MAXIMUM ZONE 4 COMMODITY RATE MULTIPLIED BY THE QUANTITY DELIVERED TO THE ALTERNATE DELIVERY POINT(S) (UP TO BUT NOT EXCEEDING THE FIRM CONTRACT DEMAND ESTABLISHED UNDER THIS AGREEMENT FOR GAS QUANTITIES TRANSPORTED WITHIN THE FIRM CONTRACT DEMAND).** CG&E shall continue to receive the Discounted Demand Rate and Discounted Commodity Rate for the remainder of its contract demand, if any, in excess of the quantity delivered to the alternate delivery point(s).