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I. General LDC Issues

A. Introduction

1. Background on this Project

In the Spring and Summer of the year 2000, field prices for natural gas began to increase from levels that had prevailed since the early 1990s. In September 2000, the Kentucky Public Service Commission (Commission) initiated Administrative Case No. 384 to investigate these increases in wholesale natural gas prices and their impact on retail customers served by Kentucky's jurisdictional gas distribution companies.

The primary focus of the Commission's investigation (and of the investigation described by this report) was on the five major gas local distribution companies in Kentucky (collectively referred to as "LDCs"). These LDCs include Columbia Gas of Kentucky, Inc. (*Columbia*), Delta Natural Gas Company, Inc. (*Delta*), Louisville Gas and Electric Company (*LG&E*), The Union Light, Heat, and Power Company (*ULH&P*), and Western Kentucky Gas Company (*Western*).

During Administrative Case No. 384, the Commission gathered information from the five major LDCs, conducted a series of public hearings, and issued an order on January 30, 2001 setting forth its findings on numerous issues. Therein it required the LDCs to file written reports on several topics, including their gas procurement activities. After receipt of the LDCs' reports and intervener comments, the Commission issued its final Order on July 17, 2001. In that Order, the Commission stated that it would conduct an audit focused on the LDCs' natural gas planning and procurement strategies. The Commission further stated that such an audit would assist it in evaluating whether the LDCs' planning and procurement strategies are appropriate in today's more volatile markets.

To provide for the required management and process audit of the natural gas planning and procurement strategies of these five LDCs, the Commission issued a Request for Proposal dated November 16, 2001 (*RFP*). Subsequently, The Liberty Consulting Group was selected to perform the audit. The Liberty Consulting Group *(Liberty)* is a management and technical consulting firm that specializes in the public-utility industries and that has extensive experience in conducting management and operations audits of the type described by the RFP.

Liberty started the work for this project in February 2002. Liberty issued a number of data requests to each company, and made at least three visits to each one to interview members of its staff regarding their gas-procurement planning and procedures. This report is the culmination of Liberty's review.

2. Report Organization

This report is organized into three major sections as described below under items **a, b**, and **c**:

a. Section I – General LDC Issues

(1). Purpose of Section I

The purpose of Section I of this report is to provide a foundation of information for the many different readers of this report. Because the audience of this report represents many diverse backgrounds, and therefore many different points of view, Section I first should be considered a primer written for some readers who might desire overall background information on some of the important elements on natural gas planning and procurement. Section I has also been written to suggest strategies for consideration by the LDCs. For example, each of the five Kentucky LDCs examined in the course of this project has different views on gas forecasting strategies, and on hedging strategies that will work best for their own utility. Thus, Section I chapters do not try to establish a particular forecasting or hedging strategy that will best work for any one utility, but instead these chapters are written to present a broader perspective of options that are possible, and that should be considered. Finally, Section I has been written so that it may be a vehicle for sustaining avenues of discussion between the many stakeholders interested in natural gas planning and procurement in Kentucky.

While the chapters of Section I do contain some general recommendations, they are presented for two purposes:

? Provision of a menu of procedures and strategies that Liberty feels should be considered by each of the LDCs as they optimize their own planning and procurement programs, and

? Provision of a range of possible options in order to enhance ongoing discussion between the LDCs, the Commission, the Commission Staff, the public, and other stakeholders interested in Kentucky natural gas issues.

Liberty's recommendations for LDC action specific to each LDC are contained in Section III of this report.

(2). Contents of Section I

Section I of the report is broken down into the following five chapters:

Section I.B - Kentucky Natural Gas Price Information

This chapter of the report discusses the nature of the problem that led to Administrative Case No. 384 and the subsequent impacts that increased natural gas prices have had on both the Kentucky LDCs and their customers.

Section I.C – Impacts of Hedging on the Kentucky Gas Market

This chapter of the report discusses hedging as it relates to Kentucky LDCs. This is a subject that is relatively new to the Kentucky LDCs, and that attracted some interest in the Commission's January 30, 2001, Order in Administrative Case No. 384. (See, *e.g.*, pp. 12-13.) In this chapter, Liberty presents some general discussion of hedging, and some general analysis of the companies' 2001/02 hedging programs. This chapter also includes an analysis prepared by one of the companies on the efficacies of financial hedges and gas storage in mitigating gas-price volatility. The chapter on hedging ends with some recommendations and suggestions for specific questions that Liberty believes the Commission and the LDCs should address as they review the results of the companies' pilot hedging programs for the winters of 2001/02 and 2002/03.

Section I.D – GCA Mechanism, Budget Billing and the Uncollectibles Issue

This chapter of the report presents expanded discussion of subjects raised in the Commission's January 30 Order. Those subjects are a) the GCA mechanism, b) budget billing, and c) the companies' problem with uncollectible accounts.

Section I.E – Background Discussion on Natural Gas Forecasting

This chapter of the report presents a summary of the important elements of natural gas forecasting. This chapter also presents Liberty's view of "best practices" in this important area of natural gas supply planning. While Section III of the report presents company-by-company evaluations of each LDC's requirements forecasting as part of our review of their gas-supply planning, the planning discussion in this chapter provides context for our comments about each company. As we advised the companies in the course of our work with them, it is not our recommendation that each one adopt every step in the best-practices process that we describe. Rather, we expect that all of the companies would be looking continuously for ways to improve their forecasts, and we offer our suggested process as a "road map" of possible improvements, based on our experience in this area. We believe that every step in our recommended process would result in an improved set of forecasts; the question that applies to each company is whether each succeeding step offers sufficient improvement to warrant the investment of time and money that would be necessary for implementation. We recognize that in some cases, the chosen planning process for an LDC might be the subject of further discussion between the company and the Commission's Management Audit Staff.

S*ection I.F – Impacts of Affiliate Relationships on the Kentucky Gas Market*

This chapter of the report discusses affiliate relations as related to Kentucky LDCs. The area of affiliate relationships has been a consideration in the conduct of the gas-supply function for some of the Kentucky LDCs for a long time. Each of the five LDCs is involved in affiliate activities on some level. Section III of the report provides a detailed description of the affiliated activities of each of the five Kentucky LDCs.

The reason for increased emphasis on affiliate relations in the current audit relates to two factors: a) consolidation in the utility industries means that affiliate-interest issues come up more often than they have in the past; and b) Kentucky has a new (or recently-revised) statutory framework that applies to the conduct of utility businesses in the Commonwealth. Thus, this chapter on affiliate relations provides an overview of the influence of both of these factors on conduct of the gas-supply function in Kentucky. Again, company-by-company reviews of affiliate-relationship issues are presented in Section III of the report.

b. Section II – Summary of Kentucky LDC Distinguishing Characteristics

This section of the report presents, in summary form for quick reference, comparative information about each of the five LDCs that are the subject of this audit.

c. Section III – Company-by-Company Reports

This section of the report presents detailed discussion, findings and recommendations regarding the natural gas planning and procurement strategies for each of the five LDCs.

II. Summary of Kentucky LDC Characteristics

Utility:	Columbia Gas of KY	Delta Natural Gas	LG&E	ULH&P	Western KY Gas
KY HQ Location	Lexington	Winchester	Louisville	Covington	Owensboro
Parent:	NiSource, Inc.	same	E.On AG (Ger.)	CG&E	Atmos Energy Corp.
Gas meters in service				87,716	182,275
Customers	142,161	39,590	305,228	86,279	
Annual Throughput - BCF	56.00	11.97	48.70	12.80	46.50
Sales Volume - BCF	12.30	4.53	35.30	10.00	23.00
Transportation Volume - BCF	43.70	7.44	13.40	2.80	23.50
Gas Procurement Model	Service Company	Utility	Utility	Service Company	Service Division
		Asset Mgt Contract		Asset Mgt Contract	Asset Mgt Contract
Utility-Owned Storage	No	Yes	Yes	No	Yes
Hedging Program					
Approved for '01-02	None filed	None filed	Denied	Yes	Yes
Approved for '02-03	None filed	None filed	Filed	Yes	Yes
Strategic Plan	Yes - 5 years old	Yes	Yes	No	Yes
PBR	No	No	Yes	No	Yes
Customer Choice	Yes	No	No	No	No

B. Kentucky Natural Gas Price Issues

1. Recent Behavior of Wholesale Gas Prices

The chart presented on the following page (Figure I.B.1) shows how field prices for natural gas have behaved over the last ten years. The chart presents daily and first-of-the-month prices for the Henry Hub, a widely-used natural gas pricing reference point located in Louisiana. Henry Hub prices are relevant to Kentucky because the vast majority of natural gas procured by the five Kentucky LDCs comes from the Louisiana gulf region.

The chart shows that, while prices have generally been relatively stable over the period, they have tended to rise during the winter months, in fact showing significant “spikes” during the winters of 1995/96 and 2000/01, and lesser price increases during the winters of 1996/97 and 1997/98, more representative of typical seasonal pricing patterns. Prices during the year 2000 were unusual in that they started to rise earlier than in previous years. Since the winter of 2000/01, however, prices have declined to more normal levels, although the “base” level now appears to be closer to $3.00 per million British thermal units (MMBtu) than to the $2.00 per MMBtu level that characterized much of the 1990s.

Examination of the data in this chart indicates the source of the problem that gave rise to Administrative Case No. 384 and subsequently to the audit of the five Kentucky LDCs that is now the subject of this report. During the 2000/01 heating season, the price of natural gas not only reached new highs not seen in recent times, but also these high prices continued to exist for a longer period of time. In fact the chart shows that the price remained above $4.00 for almost an entire year, from May of 2000 to May of 2001.

Figure I.B.1
Henry Hub Prices

2. Impacts of High Kentucky Gas Prices

a. Customer Impacts - Termination of Natural Gas Service

The behavior of field prices during the winter of 2000/01 caused significant problems for both gas distribution companies and their customers. Many customers could not pay their bills, and thus the companies could not recover the monies they had advanced to secure gas supplies for their customers. The chart presented on the next page (Figure I.B.2) shows, for the five LDCs that are the subject of this study, the proportions of each one's residential customers whose service had to be terminated for non-payment of their gas bills. As is apparent from the chart, the proportions went up over the period shown (1999, 2000 and 2001) for all five companies.

Figure I.B.2
Service Terminations

b. Company Impacts – Increased Uncollectibles Expense

Increased prices for natural gas also impacted the companies when customers had problems in paying their bills. The chart presented on the next page (Figure I.B.3) shows, for each of the five LDCs, the ratio of the company's actual uncollectible expense to the allowance for uncollectibles that was approved as part of each one's last rate case. This indicates that customers were not the only ones who suffered from the gas price increases experienced during 2000 and 2001. A complete discussion of the uncollectibles issues is included in Chapter I.D of this report.

Figure I.B.3
Uncollectibles Expense

C. Impacts of Hedging on Kentucky Gas Market

In December 2000 and January 2001, market prices for natural gas increased to around $10.00 per MCF, and the impact on Kentucky consumers, and the local distribution companies (LDCs), was staggering. Although market prices began declining fairly quickly, by July 2001, the natural gas commodity price was still hovering around $4.50 per MCF, with no apparent decline in sight prior to entering the '01-'02 heating season.

In the Order dated July 17, 2001 under Administrative Case No. 384, the Commission found that LDCs should consider limited hedging programs as one means of attaining the objectives of obtaining low cost gas supplies, minimizing price volatility and maintaining reliability of supply.

There are two key issues for the Commission to consider when encouraging and evaluating natural gas hedging programs. The first issue is "What do the Commission and the LDCs mean by the term 'hedging?'" The second issue is "What should be the objective or desired outcome of an approved hedging program, and how does that objective either support or conflict with PBR objectives, and low cost supply objectives?"

Liberty has found that "hedging" is a term that implies a variety of activities, all of which intend to manage price swings in the natural gas marketplace. The objective, most often, has been defined as "minimizing price volatility," (see, for example, Commission Order dated July 17, 2001, in Administrative Case No. 384 at p.17) although 1) no measure has been made of how much volatility has been or could be mitigated, and 2) hedging plans can often lead to higher gas costs than would have otherwise been achieved.

It is with this introduction to the issue that Liberty discusses the impacts of hedging on the Kentucky gas market.

1. Background

a. Hedging in the Natural Gas Business

Energy hedge contracts are of fairly recent origin. Until the energy crises of the 1970's, both 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 was a direct outgrowth of the gas price deregulation beginning in the 1980's. The gas futures contract began trading in 1990.

Natural gas futures are a financial instrument, and can be traded for market gain (or loss) like any other commodity, or like shares in the stock market, for that matter. The need for a firm to develop and sustain hedging programs normally arises when the price volatility of 1) key raw material costs or 2) 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 the 'normal' state of affairs. It makes little sense to organize a hedging program for a price spike caused by a temporary raw material shortage. Firms may protect a position in the physical market if they use natural gas as a feedstock for an industrial process. The combinations of positions they trade are determined through sophisticated models, and their goal is to achieve a relatively stable price for their industrial input. Trading 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.

Introduction of a futures market led to an industry-wide perception that it was possible to define a market-clearing price. Because it was determined by the "market", index pricing has become a standard for gas contracts. "Indexed" prices for natural gas are prices that are reported as representative of prices paid in transactions between unrelated 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 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 for 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 of the same quantity of gas to a location in West Texas (Waha).

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 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 may impact differentials somewhat by reducing market liquidity, but the relatively short duration of gas-purchase contracts (most contracts are for one year or less) will not allow the different types of prices to diverge very far.

Indexed prices and exchange-determined prices are both referred to as "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 there is a contract between buyer and seller for a gas purchase/sale at a price equal to whatever the "index" price is at the end of the particular day (or other period of time). As a move to protect consumers, regulatory agencies contributed to this move toward index pricing by ordering utilities to contract for gas at market-clearing prices.

Contracting for gas at market-clearing prices proved to offer significant savings to consumers over the older long-term, fixed-price model. At the same time, with the constantly changing market prices, regulatory commissions and utilities recognized the need to reflect those changes in consumer rates, without filing a full rate case. The gas cost adjustment mechanism (GCA) allowed 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.

Three times in the last 10 years, gas prices have spiked sufficiently to send unexpectedly high gas costs through to consumers. The most recent experience with high gas prices was in 2000/2001, which led to high numbers of shut-offs of gas service, and an increase in the utilities' uncollectible expense. With Administrative Case No. 384, the Commission sought to answer the questions of what happened, and more importantly, what strategies can be implemented to prevent the severe customer impacts from happening again. Hedging gas prices was one alternative that was discussed.

Prior to the extreme volatility of the 2000/2001 heating season, most utilities would have defined their hedging strategy as purchasing gas during the summer for injection into storage (either their own or pipeline storage) and withdrawing that gas at a known price during the winter heating season to be blended with the gas purchased at winter index. Hence reliance upon storage as a natural hedge has been and remains a viable and meaningful hedging strategy in addition to any other benefits storage may offer.

The Commission, in its Order in Administrative Case No. 384 dated July 17, 2001, at p.5 "recognizes the importance of storage from an operational standpoint and as a means of mitigating the impact of winter price increases on consumers." Liberty recognizes that storage offers real benefits to customers, including its use as a hedge against potential higher winter prices, because storage is able to provide deliveries at a known price to the customer. Storage should also be recognized as a means of mitigating price risk or price volatility.

"Locking in price" is another hedging strategy. Under the simplest scenario, a summer/early fall price could be locked in by the marketer for the utility's benefit. The utility would expect to take physical delivery of the gas volumes in the future at a predictable, and, it hoped, lower price than the prevailing market price during the winter.

Purchasing several packets of gas for future delivery with a locked-in price would have the effect of smoothing out any market-price volatility, at the risk of having an average cost higher than market at any given time.

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 buy either physical gas or purely financial instruments at those prices. Strips are contracts for gas with composite prices for delivery over several future months. For LDCs, locked-in pricing on gas delivery typically means that someone, presumably the gas marketer, has purchased futures for the physical delivery of gas to the utility's city gate at future dates.

Call options are another hedging mechanism in which a utility obtains the right to purchase gas at a specified price. There is an opportunity to take physical delivery, or the calls may be traded as financial instruments. The options need not be exercised if market price never reaches the strike price, providing upward price protection while enabling the utility to take advantage of price decreases. Even if the calls are never exercised, there is a cost to the program due to the price of the calls and the trading costs (broker's fees).

"Costless" or "no-cost" collars are essentially the simultaneous purchase of a call and sale of a put for some volume of gas for the same amount of option premium - thus the term 'costless.' Typically, these deals would be financial in nature only. A costless collar offers the utility a low-cost means of capping the upside price exposure of a price spike. It also offers a price floor for the utility, which carries the risk of paying above market prices in a declining market. This same risk is also present when the utility puts gas into storage for the winter heating season at a price that turns out to be above market when the gas is withdrawn.

Three of the five Kentucky utilities asked for review and approval by the Commission to pursue various combinations of these strategies, in order to ensure that the costs of the programs - in terms of option prices, brokerage fees and potentially higher average gas cost - would be recoverable through the GCA.

b. Liberty Review of Current Hedging Programs in Kentucky

Three gas distribution companies filed hedging plans with the Commission for the '01-'02 heating season; two of those proposals were approved and implemented. A fourth utility conducted hedging activities that it considered to be within the realm of normal operations, and so did not file a plan with the Commission.

In general, the utilities that implemented and conducted hedging plans undertook forward purchasing programs during the summer and fall of 2001 to lock-in winter gas prices for a significant portion of their winter needs. WKG utilized NYMEX futures, while Delta and ULH&P purchased physical winter gas priced off the NYMEX. All three LDC's used intermediaries to carry their positions. WKG used Woodward Marketing (its asset manager) as its "broker", Delta's positions were carried through Woodward and Dynegy (its asset managers), while Mirant and Aquila carried ULH&P's positions. The advantage of this arrangement was that the utilities were not exposed to any FASB 133 (mark-to-market) accounting issues, nor was it necessary for them to establish brokerage accounts in their own names. The disadvantage was that the utilities with such arrangements had little flexibility to adjust their positions once it became apparent the gas market was in a downward trend.

The utilities that implemented and conducted hedging plans began putting their positions on during the summer of 2001 and finished in October. For the most part, they bought their volumes ratably using a combination of simple futures, winter strips, and costless collars.

The gas markets experienced a significant decline over the course of summer 2001 that continued into the fall. As a result, the LDCs' hedge prices ranged from $0.30 to $0.76 /Mcf more than the winter market prices. All three utilities experienced increased gas costs through their programs.

(1) Summary of Hedging Activities for 2001-2002 Heating Season

Western Kentucky Gas Proposal (Case No 1997-513)

Western Kentucky Gas Company (WKG) filed the first hedging proposal with the Commission in April 2001. The initial proposal was to purchase call options to cover approximately 25 percent of its gas supply requirements for November 2001 through March 2002, at a projected cost of $4.9 million. The proposal approved by the Commission on June 15 was modified to use futures contracts as the preferred hedging instrument, with estimated transaction costs of approximately $236,000. Futures contracts were purchased in summer and fall, 2001, for the upcoming winter heating season. These were financial instruments only, with no intention of taking physical delivery.

WKG Results

WKG continued to increase its forward positions during the summer and fall of 2001. The driving force seemed to be its pledge to hedge 25% of its winter supply. WKG did not modify the volume targets in its hedge plan, although its costs were growing.

According to WKG's *Hedging Report* (Case # 1997-513) filed March 22, 2002, the average price of the hedged volumes was $3.66/MMBtu. The hedge program added $5.7 MM to gas costs for the winter, or $.30/MMBtu for the entire winter load. The program was deemed a success. "Western's initial hedging program has proven successful in stabilizing gas costs." (Case #1997-513)

Union Light, Heat and Power Company Proposal (Case No. 2001-128)

In May 2001, Union Light, Heat and Power Company (ULH&P) proposed, and the Commission approved July 16, 2001, with slight modification, a hedging plan intended to mitigate price volatility. ULH&P planned to buy a percentage of the November 2001 through March 2002 base gas supply on a forward basis (setting the price ahead of time, rather than allowing the price to fluctuate with the market). The plan consisted of fixed-price contracts, cost-averaging instruments based on NYMEX strip prices (volumes purchased at an average of NYMEX futures prices for the winter period), price caps (call options), and costless collars. In each case, ULH&P expected to take physical delivery of the gas. The Kentucky Attorney General's office opposed having ratepayers bear the cost of the instruments (primarily the call options), and the Commission limited the percentage of gas that could be purchased under call options. All of the other instruments had no associated direct costs.

ULH&P Results

ULH&P noted that the hedging program cost more than if the company had simply bought gas during the winter at first-of-the-month prices. Average cost for the entire hedge package was about $0.76/MMBtu over the winter market prices. ULH&P noted that winter cash prices have been less than the summer forward market in seven of the last ten years. In other words, a hedging program would have cost money in seven of the past ten years, but would have been of significant value during the ’00-’01 season and would have produced more savings in the three years than the costs of the other seven years. The company stated that hedging does not equal lowest or even low prices. It is a means of reducing volatility.

Louisville Gas and Electric Company Proposal (Case No. 2001-253)

In August 2001, Louisville Gas and Electric Company (LG&E) submitted a proposal to purchase call options, rather than futures contracts, to protect consumers from price “fly-ups” while retaining the ability to take advantage of falling prices. The objective, then, was price mitigation rather than decreasing volatility. In addition to establishing a maximum dollar amount that could be used to purchase call options and passed on to ratepayers to cover expenses of the plan, LG&E also proposed to establish a maximum volume to be hedged during the referenced hedge period, which took into account the volumes delivered from storage at a known price. The call options were intended to be financial instruments only, with no physical delivery, and LG&E proposed that all costs and benefits of the hedging plan flow through the GCA mechanism without impacting performance under the PBR because the goals associated with hedging were different from the least-cost purchasing strategies of its gas supply cost PBR mechanism.

The Kentucky Attorney General objected to the proposal as being limited in nature, inherently risky and the benefits speculative, lacking definition as to volumes to be hedged and cost of the call options, and assigning all costs to ratepayers, while creating the opportunity for shareholders to benefit under the PBR. The Commission ultimately denied the plan for not being timely (due to its August submission) and because market conditions for the upcoming heating season had changed substantially, making hedging proposals less urgent.

Delta Natural Gas Company (no filing)

Delta Natural Gas Company (Delta) did not file a plan with the Commission because the company felt 1) its activities did not involve financial instruments, 2) the forward purchases were for physical gas, and 3) the purchases were not outside its normal procedures. Delta locked in supply from its asset managers by buying winter strips – average prices for the three months of December, ‘01, January, ’02, and February, ’02 – for physical delivery of those minimum volumes it anticipated selling during a warmer than normal winter for the northern part of its system, with the balance to be purchased at index prices. (The southern part of the system is supplied primarily from storage gas purchased during the summer.) The marketers held the positions through the fall and made delivery off the contracts during the winter.

Delta Results

Delta said its hedging objective was to reduce volatility in accordance with the directive of the Commission's Order in Administrative Case No. 384. Delta hedged its entire winter base load at prices that ultimately proved to be over market, as did the other utilities, but this was during one of the warmest recorded winters, which affected both prices and demand. Moreover, its arrangement with its two marketers prevented it from modifying those positions once they were put on.

Columbia Gas of Kentucky

Columbia Gas of Kentucky (Columbia) did not engage in hedging activities because of the large number of Customer Choice customers. Managing price and volatility was felt to be an issue between the customer and their chosen marketer.

(2) Liberty Conclusions

Using financial hedging as a means of mitigating price risk or price volatility for consumers is still experimental. Every approved plan required the utilities to monitor results and report back to the Commission, so that modifications could be instituted as needed. All the parties recognize that hedging is a new area, and much needs to be learned before such plans can become routine fixtures in a gas supply plan. It was in this context that Liberty reviewed the completed and proposed hedging plans.

In general, Liberty found that the utilities that implemented and conducted hedging programs followed the direction of the Commission in developing and implementing their respective plans. Our specific conclusions are detailed in this section.

Objective: Reduce Price Volatility

Increased costs aside, the utilities that implemented and conducted hedge programs considered their programs a success due to the claimed reduction in price volatility and/or large price swings. This occurred even though no *specific* volatility reduction objectives were set forth in the either the Commission's Order or the utilities' original plans; nor was any identified during Liberty's interview sessions or in Liberty's formal assessment of the programs.

Price volatility in the futures markets is usually measured as a % range of daily price moves. Assume natural gas price volatility is quoted at 50%. That means a daily price move of 50% (price of gas is $2.50 +/- 50%) is within one standard deviation (66 2/3 of all observations exhibit a price move of 50% or less.). Thus a hedge program objective designed to reduce price volatility could reasonably be expressed as a goal to reduce volatility from 50% to 20%, for example. However, none of the documents submitted by the utilities regarding hedge programs identify specific volatility reduction objectives.

Contrary to the focus of the experimental plans approved by the Commission, Liberty suggests that reducing volatility is not the appropriate objective. Volatility is not an issue unless the peaks are uncomfortably high. If the peaks are too high, then price management - or more precisely, high price avoidance - becomes the objective of the program.

Method: Mechanistic Buying

The utilities' stated objective of minimizing volatility through the hedging programs they implemented led to a mechanistic focus on hedging pre-determined volumes at levels approved by the Commission in the face of a declining market. In every case, the utilities kept adding to their positions despite growing costs. The Commission approved the hedging programs of two of these utilities. Therefore, there may have been a concern that approval by the Commission implied that only by following the plan to the letter could the utility be assured of cost recovery.

Liberty understands the Commission's and Attorney General's concerns about approving a program that is insufficiently defined with regard to costs, volumes and outcomes. However, because these programs will operate in a market that no one can predict, there must be enough flexibility built into any program to take advantage of changing conditions. Further, utility employees responsible for the implementation of the plans must be knowledgeable enough about the futures market to recognize when conditions warrant a change in the plan.

Method: Professional Trading Resources

Futures trading and hedging is not a one-time event. Positions must be managed. Faced with a similar downward market, a trading group not operating in a regulated environment may have taken steps such as shorting the market as it dropped and/or closing out the losing positions to reduce the mounting costs. This must be done by an employee or agent who is working in the utility's interest. A commodity broker is not an account manager, but someone who executes instructions. Liberty suggests that utilities opting for complex hedging programs retain sufficient expertise to make sure the program is properly managed within the confines of what is approved by the Commission.

Method: Costless Collars

The utilities that implemented and conducted hedging programs appear to have been motivated towards costless collars vs. pure call options by the Kentucky Attorney General's concern over the potential cost of call options. As noted above, costless collars offer the utility a low-cost means of capping upside price exposure, but at the risk of paying above market prices in a declining market. Although at first glance a costless collar offers upside price protection seemingly for free, it is not without its own set of risks, in addition to being caught in a declining market.

First, a costless collar must be struck with an individual counter party. There are no listed costless collars. That means that buyer must shop the market for quotes from *reliable and creditworthy* counter parties. (This issue is further discussed under risk, below.)

Second, in the process of shopping for quotes, the buyer must understand how such options are priced in order to strike a reasonable deal. In this process, the buyer is likely to find widely differing offers.

During the early 1970's, a tool was developed to assist buyers understand and work with option pricing. Fisher Black and Myron Scholes developed an option pricing model that has since become the gold standard for pricing derivatives. Generally it is referred to as the Black/Scholes Model.

Although the model is based on complex mathematical equations, software packages are available that can price options quickly using very simple inputs. Indeed, the Black/Scholes Model is *the way* traders analyze option prices. Since many derivative deals are custom designed (the options involved are not listed, e.g. costless collars), knowledge of and the ability to use the Black/Scholes model is fundamental to being an informed buyer. If the options buyer is unaware of the model or does not understand how it works, then the buyer will not be able to assess option deals appropriately. None of the three utilities that implemented and conducted hedging programs used the Black/Scholes model. The need for the use of such complicated models is alleviated if the utility uses a bid program to determine the availability and the cost of the financial derivative, for example, the cost of the option and the associated strike price. Shopping for the lowest price can be an effective tool allowing utilities to search for the best price available in the market.

Finally, the two parties must fashion a mutually satisfactory contract. Although many of the brokerage houses have sample contracts, those only offer a starting point for negotiation. For these reasons, Liberty suggests that the interest in costless collars may be misplaced.

Costs: Average Gas Price

For the utilities that implemented and conducted hedging programs, focusing on volatility rather than price resulted in gas costs from $0.30 to $0.76/MCF higher than buying at market, resulting in higher costs to ratepayers. Of course, if prices had risen to levels of the 2000-2001 heating season, the average cost would have been below market, and the plans would have been a ratepayer benefit, rather than cost. The problem, of course, is that, statistically, higher costs would be the result in about 7 years out of 10. These costs must be factored into any evaluation of a hedging program.

This would seem to indicate that in general, decisions to conduct hedging should be carefully considered. However, the Commission's language suggesting possible disallowance may also have motivated the utilities. Specifically, the Commission's July 17 Order at p. 17 stated that "LDCs that forego developing such [hedging] strategies may place themselves in the position of sharing some of the risk to which customers have been exposed in the past."

Another concern is how this higher-than-index price can be factored into utility PBR programs. The Commission determined these costs to be fully recoverable from customers since customers would be the beneficiaries of such hedging activity. Its July 17, Order in Administrative Case No. 384 states that "[i]nasmuch as customers bear full risk of wholesale price changes, it is appropriate that they bear the full cost, within reason, of any Commission-approved price mitigation strategies." Order at p.17. In addition, the Commission also recognized in its July 17 Order that hedging programs and PBR programs may be at cross-purposes when it stated on pp. 17-18 that "there is some inherent conflict" between the goals of a hedging program and those of a PBR mechanism. It also recognized Western Kentucky Gas as a model showing that "a hedging program can be implemented so as to be separate from a PBR". The Commission concluded by recognizing that "it recognizes fully the need for flexibility and for coordination of such [hedging] proposals with PBR policies."

Liberty suggests that the situation of having the PBRs and the hedging programs simultaneously pulling in opposite directions should be revisited by the Commission. There are a number of alternatives. First the Commission could retain the PBR mechanism and reject hedging based on the presumption that at-index purchasing practices provide reasonable gas costs. Second, the Commission could rule that hedging programs over-ride PBR programs and find that either the use of the approved hedging program constitutes reasonableness or determine reasonableness after the fact. Third, the Commission could set a target consumer gas price, assume the reasonableness is meeting that price, and let the utilities hedge however they choose.

Liberty, at the end of this report, will suggest a fourth option for consideration: define hedging strategies that are consistent with an over-riding objective of doing no worse than the market; *i.e.*, meeting a target index. Those strategies focus on one objective, protecting customers from price "spikes". Focus group studies conducted in Kansas suggest that this structure - protection from price spikes, but retaining the ability to follow market prices down - fits what customers want the companies to do.

With narrowly-focused hedging strategies, it should be possible to have hedging programs and PBRs operating concurrently. The hedging programs would have costs, but should result in savings relative to the target indexes if prices spike upwards.

Costs: Focus on Trading Cost

Liberty's review indicates the utilities that implemented and conducted hedge programs focused on the wrong cost elements. There was much discussion of how much had been saved in transaction costs or option costs while the gas costs incurred under the plans increased measurably. In part, this was a logical response to concerns that transaction and option costs would result in no assured benefit to the ratepayer. The effort to avoid these costs, however, resulted in hedging programs that ultimately cost consumers in increased gas costs.

Liberty suggests that all the parties acknowledge that hedging programs will incur legitimate costs by the utility that are appropriately borne by the ratepayer in return for some amount of price protection. The goal of any hedging program should be to make sure that, over time, the accumulation of costs will be offset by the benefits to ratepayers should price spikes like those during the winter of 2000-2001 again occur.

Risk: Counterparty Reliability

The issue of counterparty risk is evident throughout Liberty's review of the hedging programs. The willingness to let the marketers carry hedge positions may have avoided FASB 133 reporting issues and margin account requirements, but the tactic reduced the utilities' ability to manage their positions and increased their counter party risk.

First, some of the utilities that implemented and conducted hedge programs did not have letters of credit from their marketers to back their hedging positions. There was no way for those utilities to know if the hedging instruments had been purchased. It is not unheard of for marketers to commit to a fixed price but not purchase futures or options, counting on a declining market. (Note the comment by ULH&P that actual market price for winter gas had been less than the summer forward market in 7 years out of 10.) In this case, over the term of the fixed price arrangement, a marketer might count on buying on the cash market, for example, at $3.00, but selling to the utility at the agreed-upon price of, say, $4.00. The utility thinks it has price protection; the marketer is making money, and there is no apparent risk. Given the same circumstances, but a rising market, the utility must depend on the marketer to deliver at $4.00 gas that is being purchased in the market for $5.00. If the marketer can't deliver, the utility has lost whatever fees it paid to the marketer, *and* it has to go out into the market to meet its supply requirements. Liberty notes that ULH&P paid no fees to its marketer for hedging.

Costless collars, the focus of some of both the '01-'02 and '02-'03 hedging proposals, has even greater counterparty risk issues. Costless collars are privately negotiated deals – there is no protection from a recognized exchange, no recourse except to the counterparty. The performance capabilities of the counter party in such a situation are always a concern, but particularly now with credit problems becoming increasingly apparent for so many potential counter parties. It is imperative that the reliability and creditworthiness of counterparties be thoroughly investigated. Moreover, the intended structure of the proposals – the marketers will actually hold the option positions – doubles the utilities' performance risk. They will have counter party exposure with both the marketer and the party who holds the other side of the collars.

Summary

The first-year, "try it out" basis of the hedging programs was intended to lead to a better understanding of how the programs worked for the utility, the consumer and the Commission. Liberty suggests that all the parties understand the conclusions described in this section about the programs as they have operated to date, and work to resolve those concerns in the development of future hedging plans.

2. Developing a Hedging Strategy

Liberty's review of the proposals, implementation, and results of the utilities' hedging strategies suggests that, in addition to the conclusions above, the Commission and each utility consider the following points when crafting policies related to evaluating hedging strategies.

a. Context Surrounding a Hedging Strategy

The Commission and the utilities recognize they are operating in a very different marketplace today than at any time in the past, a fact that led the Commission to consider approving limited hedging activities under Administrative Case No. 384. In addition, each of the utilities operates under different circumstances and has widely different resources to use in developing its own strategies. Therefore, how each utility may choose to implement a hedging strategy may differ from one to the other. In addition to understanding how deregulated natural gas prices, unbundled services from pipelines, unbundled utility services, and the resulting changes in the buyer/seller relationship have all changed the marketplace, Liberty suggests that several other contextual issues need to be considered.

(1) Natural Gas Price Spikes

The $10.00 prices of the winter of '00-'01 were a statistical anomaly. Over a 10-year period, gas prices have run up 3 times. The mean gas price over the period has been $2.67, and there have been approximately 90 days when market prices went over $5.30 (two standard deviations from the mean) and only around 60 days when prices spiked over $6.00. This implies that any response would be more appropriately viewed like property insurance – some level of protection in case of a statistically rare event. Both the likelihood of price spikes, and the probable duration of any abnormal markets, need to be factored into a hedging plan.

(2) Disconnect Between Price and Fundamentals

The introduction of financial instruments – futures, calls, etc. – have helped create a disconnect between the prices tied to those instruments (including market prices) and what would seem to be a logical response to supply and demand - the fundamentals of the natural gas marketplace. Thus, a hurricane in the Gulf can create at least temporary havoc in the financial marketplace for natural gas, while the fundamental issue that drilling rigs have successfully withstood tropical storms for decades goes unrecognized. This disconnect is evident in two distinct approaches to looking at the natural gas marketplace – technical analysis and fundamental analysis.

"Technical analysis" basically assumes that prices follow certain patterns. In many respects technical analysis is the opposite of "fundamental analysis" which says future commodity prices reflect basic supply/demand trends. Although many non-professional commodity price spectators consider technical analysis just short of voodoo, in fact, most trading professionals use 'technicals' as their prime analytical tool. The technical approach does capture the (mob) psychology of the markets which fundamental analysis ignores. Given the very short-term view of commodity markets, market psychology tends to be the prime mover on prices. Thus, understanding all the aspects of the natural gas industry does not necessarily mean that gas prices can be predicted with any accuracy.

(3) Experimental Nature of Hedging Component

Commissions and utilities have developed many responses to the changing nature of the gas distribution business. Some of the responses that have proven to help smooth prices to consumers include the GCA, storage gas as a "natural hedge," and budget billing programs. Most of these responses have a lengthy history of success and a degree of predictability. Hedging programs, on the other hand, are relatively new to the utilities and the Commission and the outcomes of such programs can be unpredictable. Hedging is only one possible component of a strategy to protect consumers from price risk and price volatility.

Recognizing the experimental nature and potential costs to consumers of financial hedging, Liberty suggests that the utilities continue to focus on traditional hedging strategies available to them. Traditional strategies to reduce volatility or mitigate the impact of higher prices on consumers that are currently available to LDCs include the use of the GCA as filed on a quarterly basis, budget billing, and natural gas storage. Utilities should evaluate the use of financial hedging to augment these traditional strategies.

Administrative Case No. 384 stimulated LDC thinking about the subject of hedging. In reviewing the companies' filings in Administrative Case No. 384, Liberty found that one of the companies (ULH&P) had conducted some computer-simulation-based studies of the effects on gas costs of the following different gas price management strategies:

- increased gas storage
- a certain financial hedge, namely fixing the price of a portion of its winter-period supply through the use of NYMEX futures
- a combination of the two hedging techniques (increased storage and "locking" prices).

ULH&P's results are particular to the assumptions that it made and to the cases that it tested. Those results are useful, however, in illustrating certain realities about hedging, both physical and financial, and in providing particular questions for further discussion.

ULH&P uses an in-house, spreadsheet-based computer program to match its gas-supply portfolio to its forecasted load. The Company's supply portfolio consists of pipeline and storage capacity, a propane/air peaking plant, production-area contracts for "base-load" and "swing" gas supply,[1] and a peaking service delivered to the Company's city gates.

The Company uses its spreadsheet model to calculate the quantities of each resource that it will need in order to supply its load at least cost. As is the case with the other companies, ULH&P forecasts its load by analyzing the relationship between the amount of gas that it dispatches to its customers (its "sendout"), and the weather. These analyses are done by customer class, so that the usage characteristics of each type of customer can be captured individually. These analyses are updated annually, and adjusted for changes in the Company's numbers of customers.

The Company also uses a Monte Carlo simulation add-on to its spreadsheet model as part of its forecasting process. The Monte Carlo simulation allows weather (and other variables) to be specified to the model as randomly selected values subject to set criteria, rather than as specific inputs. The Monte Carlo simulation samples 10,000 possible combinations of input variables in its computations, and presents its output as probability distributions of expected values for forecast parameters of interest.

The Company used these tools to evaluate how hedging techniques might change its expected gas costs. The "figure of merit" for its evaluations was the estimated per MMBtu gas cost for an entire year. Probability distributions of expected per-unit gas costs were calculated for each scenario. Scenarios evaluated were as follows:

- Base Case: business as usual. In a normal winter, ULH&P used storage capacity equivalent to 15 percent of its annual requirements for system supply.
- Hedging Winter Base: In this case, the Company fixed the price of half of its winter-period, base-load quantities by purchasing NYMEX futures the previous summer.
- Additional Storage: For this case, the Company doubled the amount of gas that it expected to withdraw from storage during the heating season. Contract quantities for storage and re-delivery capacity were doubled, and quantities for transportation and peaking were correspondingly reduced.
- Additional Storage Plus Hedging: This case used the hedging measures from both of the other cases: doubling the amount of winter-period supply taken from storage, and fixing the price of winter-period, base-load quantities through the use of NYMEX futures.

For analysis of these scenarios, the Company used the eleven years' price data that have accumulated since the NYMEX natural gas contract began trading. The Company also used 30 years of weather data for the analysis.

The results are shown in the following table:

[1] Contracts for "base-load" gas supply generally provide that the nominated quantity will not change over the course of a month. "Swing" contracts, on the other hand, generally provide that the nominated quantity can change every day, and that the nominated quantity can be zero.

Case	**Average Gas Cost per MMBtu**	**Standard Deviation**	**Chance of Lower Cost**
Base Case	$3.21	$1.25	--
Hedging Winter Base	$3.19	$1.15	34%
Additional CGT Storage	$3.20	$1.17	25%
Additional CGT Storage and Hedging	$3.19	$1.11	25%

Source: "Possible LDC Strategies for Mitigating Higher Natural Gas Prices", filed by ULH&P in Administrative Case No. 384, March, 2001.

The results shown for the various scenarios are remarkably similar. The average total gas cost across the four cases differs by only 2 cents per MMBtu, or less than one percent. One result that differs noticeably across the four scenarios is the standard deviation, which is a measure of the dispersion of the probability distributions. The fact that the standard deviations for the hedging scenarios are smaller than that for the Base Case suggests that the results in the hedging scenarios exhibit less variation than the Base Case; *i.e.*, there is less chance of a relatively low price or a relatively high price in the hedging scenarios than in the Base Case, with the "double-hedge" case (more storage plus financial hedges) having the lowest variation.

Notice also that the hedging scenarios, even though they have a slightly lower average cost per MMBtu, have a less than 50/50 chance of resulting in an average price that is lower than that of the Base Case.

(4) Hedging and Reasonableness

With the advent of natural gas index pricing, which has been deemed to reflect market conditions, reasonable purchasing decisions have been those made at index. Thus, when index went to $10, those purchases were as reasonable as purchases at an index of $2. The Kentucky Attorney General has raised objections to the costs involved with hedging that will be borne by consumers. Commissions and utilities will continue to wrestle with the questions of what defines reasonable gas purchases.

(5) Operational Considerations of a Hedging Program

Regardless of their view of formal hedging, many energy firms have not developed hedge programs due to the expense and complexity of such an endeavor. Even those who are active cash market traders often view trading in the futures market as a full step beyond any price management tactics they are presently employing.

Their caution is well founded. While Liberty is not recommending that the Kentucky LDCs establish formal trading operations, nor does it appear that the Kentucky Commission wishes them to do so, the following is only presented to demonstrate the complexity of such formal trading operations and at the same time provide a frame of reference for the basic operational factors that should be considered by LDCs in structuring financial hedging programs. For example, all LDCs should have a risk management plan, and the associated control systems, as outlined below. Further, Liberty suggests that utilities opting for complex hedging programs use the following outline to ensure that their program is properly managed within the confines of what is approved by the Commission.

An actively managed trading program that incorporates futures or other financial hedge instruments (e.g., options), typically requires investments in the following:

Computer and information technology resources

Futures trading is a real-time activity. The firm's trading group needs access to real-time quotes, that are provided via *direct connection* to the relevant market (e.g. NYMEX or MERC). Most of the internet services (free or low cost) provide prices with a time delay. Not surprisingly, the real-time quote systems are much more expensive and often require special software and communication connections to run on typical office PC's.

The trading group needs price tracking and analysis software. The latter provides the traders with insights into future market direction and/or the capability to conduct 'what-if' analysis of various trading strategies. Again, these packages are not cheap and the staff needs to be well-trained to utilize them.

A futures trading group also requires specialized accounting and financial reporting software – not only to meet the requirements of various FASB's (in particular, FASB 133) but also to monitor the trading group's risk exposure on a daily basis.

Control systems – Delegation of Authority

The creation of a trading group often presents a firm with a number of new control issues that must be adequately addressed if the firm is to avoid unpleasant surprises.

One key concern is *delegation of authority*. Most firms have some sort of layered spending authority delegation, e.g. a manager has a $10,000 limit, a director has a $50,000 limit, etc. Compare those limits to the dollar value of relatively small trades. On the face of it, a junior trader often has more spending latitude and can create far greater risk exposure for the firm than a senior vice president. Moreover, the speed at which that junior trader's deals can turn negative greatly underscores the nature of the delegation risks. At the same time, speed is of the essence. Trading decisions have to be made by the traders. There is no time to 'send decisions up the line.' Delegation limits vs. speed of market pose a substantial control dilemma.

Control systems – Paper Trails

Firms with trading operations must always be alert for 'surprise' losses that result from deals that went unrecorded in the company's books. One way to insure authority limits are not being exceeded and all business is being properly recorded is establish a separate and independent function to monitor the flow of trading business. Firms will often arrange for their brokers to send copies of all transactions, margin account data, open positions valuations, etc. to the firm's accounting group at the same time the deals are executed or those reports are issued. The accounting group is then in a position to verify whatever financial reports the trading group produces.

Control Systems – Financial Reporting

Most firms design their financial reporting systems to provide monthly statistics. Those results are often compared to some spending or profit target and corrections are made accordingly. Again, the speed of the commodities markets renders a monthly financial control system useless. For a trading group, the control cycle is at least daily if not intra-day. A trading manager wants to know where the 'trading book' stands at the close of business every day. The rub is the accounting group either does not appreciate the need for such timely data or does not have the resources to provide daily data. Consequently, the trading group is often left to its own devices in the implementation and maintenance of its financial reporting and control systems.

Dedicated Financial Resources

In order to establish and maintain positions with listed futures contracts (e.g. a NYMEX or MERC contract), the producer/consumer must establish a trading account with a brokerage firm who can execute trades on the trading floor. To open a trading account, the producer/consumer must provide his broker with margin funds – typically *at least 10%* of the dollar value of the producer/consumer's open positions (An 'open' position is one where the customer is long or short on a futures contract that has not yet matured.) For a corporate account, e.g. a utility, the size of the margin account could be in the millions of dollars.

Margin funds are essentially dead resources. They earn little, if any interest income for the customer and are there solely to protect the broker if the market turns against the customer's positions. If the market does turn against the customer such that the current value of his position is less than his initial investment, the broker will require additional margin to maintain the position. Needless to say, margin calls always come at the worst time. When a call comes, the customer must *immediately* wire additional funds to maintain his position. In order to do so, the various authorizations and banking arrangements must be in place in the customer's firm before the call comes. If the funds do not arrive in time (close of the trading day), the customer's position will be liquidated and the paper losses become real.

Talented, Dedicated Staff

Along with the right equipment, systems, and resources, such a group has to be properly staffed with the right people. The kind of people who seem to do well in a trading environment – quantitatively inclined, independent minded, risk takers – may be more or less available internally depending on the firm's line of business. The trading mindset epitomizes investment banking for example. In many respects, it represents the opposite of the business values found in the utility industry.

Costs of Trading Activities:

As discussed above, an actively managed trading program that incorporates futures or other financial hedging instruments would likely require the LDC to incur additional costs. These kinds of costs (computer and information technology resources, control systems, financial resources, and potential additional staff) are costs that will be imposed upon utilities but not recovered as hedging costs through the GCA. These are costs of operating a hedging program that are outside of financial impacts on gas costs, but increase O&M, and have not hitherto been recoverable through the GCA. Liberty suggests that the Commission consider these incremental costs for recovery by the utilities through their respective GCA mechanisms. It should be recognized that these incremental costs should be borne by the customer that is the intended beneficiary of the financial hedging program. Without providing for cost recovery, investments in such activities may be problematic.

A Risk Management Policy

Central to any approach to hedging in natural gas markets is the need for an overall corporate Risk Management Policy. Following is an outline of a typical Risk Management Policy:

Risk Management Policy Outline

Focus:

The policy covers price risk exposure due to forward gas commodity purchases.

Objective:

Provide policies and procedures to ensure the company is not exposed to economic loss beyond intended levels.

The exposures this policy is directed toward would typically be created by buying natural gas futures, fixing commodity prices in advance, or otherwise obtaining commodity supplies outside the ‘normal’ purchasing practices (e.g. buying at index).

Definitions:

The policy should define the various terms associated with Risk Management, including Risk Management itself, Market Risk, Credit Risk and Operational Risk. Other terms such as collars, puts, calls and other swap options must be defined.

Speculation:

The policy must clearly establish whether or not the company will engage in speculative activities related to natural gas procurement.

Responsibilities:

The policy must clearly define the responsibilities of the various positions involved in natural gas risk management activities.

Limits and Authority Levels:

The policy should establish both purchase limits and exposure limits (value-at-risk) as well as authority levels for the organization in a matrix similar to the following:

Procurement Specialist (Traders)	$X
Director of Procurement	$XX
V.P. of Procurement	$XXX
President/Board	$XXXX

Note that limits are specified in dollar terms as opposed to physical volumes.

Exposure should be determined using mark-to-market methodology. Exposure limits should be calculated on an aggregated basis of all deals with similar maturity characteristics, e.g. all deals that mature in January or are driven by January prices. The company may also decide to limit total exposure at the trader or director level to $X regardless of maturities.

Deal Confirmation System:

The policy should establish a separate deal confirmation system. When forward purchase (or hedge purchase) deals are established, separate copies of the confirms should be sent to separate groups in the company, such as accounts payable, at the same time they are sent to the trading group. In this manner, the risk of surprise losses due to unrecorded deals is minimized.

Reporting:

The policy must detail the nature, frequency and distribution of reports. Reports should address topics such as the following, as well as distribution lists from the Board of Directors, through Executive Management and on down through the organization:

- Summary of physical & financial open positions.
- Summary of daily transactions, physical and financial credit exposure, using mark-to-market methodology.
- Report on hedge effectiveness.
- Limit compliance.
- Value At Risk (VaR).

Counter-party Risks:

The policy must establish the methods of addressing and controlling the risks associated with the parties with whom the company may do business.

Risk Management Committee:

Most utilities have recently established a Risk Management Committee to oversee the company's risk related activities in recognition of the new risks to which the utility is exposed in today's utility business. The membership, responsibility, frequency of meeting, and authority of this committee must be clearly defined.

b. Objectives of a Hedging Strategy Program

The articulation of objectives for any hedging strategy needs to be addressed specifically and directly. In the Order dated July 17, 2001 under Administrative Case No. 384, Finding #2, the Commission directs utilities that minimizing price volatility should be one of several objectives. Earlier, however, in the Summary of the same Order, the Commission notes that the issues addressed relate to "mitigating price risk and price volatility." The two issues – managing price risk and managing price volatility - are, in fact, different objectives, with different solutions under a hedging program.

As was evident in the winter of 2000-2001, market prices can rise to painful levels. Prices during that period were also extremely volatile - that is, they exhibited much greater swings from high to low than is normal. At issue is whether it was the high prices or their volatility that was more burdensome to the ratepayers. Some jurisdictions surveyed their consumers to determine which condition was more onerous. The results were mixed. There were some indications commercial and industrial accounts were more concerned about volatility. They could deal with higher price levels if those levels were predictable. Retail consumers, on the other hand, seemed more disturbed by the price levels themselves. (To a large extent, the smoothing mechanisms in the GCA shielded the retail customer from the raw impact of volatility.) The price level issue was more obvious.

In accordance with Commission direction, the hedging strategies implemented by utilities had as their objective the minimizing of price volatility. Locking in prices is an obvious means of limiting price swings – in fact, if all gas is locked in at a purchase price, volatility would be zero. Costless collars limit volatility between upper and lower bounds – the call and the put. Assuming storage has been filled at summer prices, its withdrawal may help bring down average gas cost when combined with volumes at potentially higher winter prices, again limiting volatility. The outcome has been successful in that gas prices to consumers have been less volatile, although no utility has actually measured how much volatility has been avoided, and at what cost. (A significant part of that cost has to be the higher-than-market average price that was the result of all of the utility hedging programs.) Volatility is a statistical measure, and companies can – and need to – assign numbers and values to the volatility they are trying to avoid.

Mitigating price risk is another possible objective. Liberty would define this as avoidance of a gas price that is "too high," or as a "price not to exceed." One possibility would be to look at the gas market price per MCF, in comparison to historical values, and to buy when the price approaches an uncomfortable level.

Liberty recommends an analytical and rigorous method, focused on the cost to the customers in their monthly heating bill.

It is clear that high consumer natural gas prices have political, social and financial impacts which consumers, regulators, utilities and legislators would like to avoid. Most often, the higher prices occur in winter, when customer usage is highest. Shut-offs increase, utility working capital decreases as the numbers of slow-pay and no-pay customers rise, and the risk of fuel-switching in all customer segments increases. Each utility must work to define a point at which rising gas bills cease to be an annoyance and, instead, become burdensome to its customers and ultimately to its own operations.

3. Liberty's Recommendations

Liberty offers the following recommendations for a hedging program that would meet the Commission's objectives of low-cost, reliable supply at market-clearing prices, while considering price and volatility mitigation. Liberty's underlying theme for presenting these recommendations is to create a forum for moving forward on the subject of hedging and for stimulating further discussion between the Commission and each of the Kentucky LDCs in order to establish hedging programs that meet the above stated objectives.

a. Collaborative Approach

Liberty believes that the best way to proceed on the Kentucky hedging issue is for the Commission and the LDCs to work together to develop optimum hedging programs specific to each LDC. Liberty believes that the guiding concept for these discussions should be development of an agreed upon objective for each of these hedging programs.

Liberty recommends that the Commission, the LDCs and other interested parties review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. Also, Atmos used different hedging techniques in other States in which it operates. The Columbia Distribution Companies, whose gas-supply operations are also conducted on a centralized basis, had hedging programs in three of the five States in which they operate. (Kentucky is one of the five, but not one of the three.) Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management that can be constructively used in these discussions between the Commission and the LDCs.

Liberty recommends that a specific area for discussion be the establishment of objectives of future hedging programs. This is discussed directly in recommendation "b" below. In this vein, Liberty applauds the Commission's adoption of a suggestion that public input be sought in selecting those objectives. Western has included a related question in a survey of its customer attitudes. Liberty's experience tells us that different customer classes will prefer different objectives. That knowledge should be incorporated into the hedging programs for each of the

LDCs, and will help the Kentucky LDCs tailor their service offerings more closely to their customers' requirements.

b. Establish Objective

Liberty recommends that the platform for any hedging program be a clearly defined objective of that program. Liberty suggests that one possible objective to be considered in discussing hedging programs would be identification of a winter gas price that should not be exceeded. Therefore, subsequent hedging actions could be geared toward upward price protection of winter purchases such that the combination of (lower-priced) storage withdrawal, any fixed price contracts and the normal price-smoothing function of the GCA in conjunction with current purchases could result in the desired price to consumers. Thus, the highest purchase price of gas that might be acceptable for some winter period may be, for example, $8.50, in order to result in a maximum cost to consumers of again only for example, $5.75.

This approach is very different from the mechanistic programs Liberty has reviewed for each of the LDCs during the course of this project. Many hedging proposals have been defined in terms of *volumes* – e.g., purchase fixed price contracts for one-half of the projected non-storage winter demand, or buying ratably over time regardless of mounting costs – rather than in terms of *expected price result*. Liberty acknowledges that the calculations for a "price-not-to-exceed" scenario are complex, requiring inputs ranging from weather probabilities, load duration curves, customer usage, projected GCA calculations, historical and projected gas prices, etc.

The advantages, however, of such a price mitigation plan are numerous. The typical hedging instrument would be call options, but at call prices sufficiently high that the cost of such calls would be quite low. As an example, Liberty has calculated that in a $3 market, an $8.50 call might run 3-8¢ per MCF, or $30-80,000 per BCF covered, plus trading fees. This level of cost would be considered insurance against the unlikely event of price spikes, and would not involve the large amounts of expenditures for options and trading costs that have been a concern in the past. Further, the consumer would be protected against highest prices, but able to take advantage of downward pricing, an opportunity which would be lost under both fixed-price contracts and costless collars. Under such a plan, the utility would purchase recognized financial instruments that do not carry the counter-party risk of costless collars, and the utility would not need to establish the sophisticated trading departments (at significant cost) that other hedging programs might entail.

Utilities, regulators, and interveners should all recognize that financial hedging practices will increase gas costs in the short term, as compared to buying gas at market-clearing prices, but may have distinct advantages to consumers over the long term.

c. Summary of Recommendations

Liberty believes the best way to meet the Commission requirements of low price, market-clearing price, reliability of supply, and price/volatility mitigation is through having the primary objective of a hedging program focus on the customers' winter heating bills. Following are suggested steps to be taken by both the Commission and the LDCs in arriving at hedging programs in Kentucky that best meet the needs of all of the stakeholders in this issue – the Commission, the LDCs and the Kentucky natural gas customers.

(1) Commission

(i) Work with utilities in defining reasonable gas purchasing practices.

Issues which might be considered include whether purchases are always reasonable, what happens if a utility's plan results in not achieving lowest possible price.

(ii) Work with the utilities and the Attorney General's office to set appropriate levels of cost for any hedging activities that can be recovered through GCA.

Any hedging program is going to cost the utility, and the ratepayers, some amount of money. In addition to the trading costs, or broker's fees, there are the costs of the hedging instruments themselves, costs associated with developing and maintaining expertise in the natural gas commodity market, risks of the WACOG under a hedging plan exceeding the WACOG without hedging (offset by the potential benefits of the reverse), etc. All parties need to acknowledge these costs, and reach consensus on what level of cost is reasonable.

(iii) Establish procedures such that the costs of the hedging programs (including, but not limited to, administrative and financial support) be recoverable from customers.

(iv) Analyze possible outcomes of such a program under PBRs, Customer Choice, rising/falling market prices, etc., or require utilities to provide their analyses of the same issues.

No one can predict the future with certainty, but "what-if" analyses are within the capabilities of the utilities. The experience from the previous programs offers indications of the kinds of scenarios that could be analyzed to limit unexpected outcomes.

(v) Establish the mechanism for utilities to have the proper balance of incentives, as well as to suffer adverse consequences if the objectives of the hedging program are not met.

Liberty's concern with hedging programs is that it is possible for a utility to be rewarded (through PBRs) at the same time that hedging programs may not be providing the anticipated results. Generally hedging programs and PBRs tend to operate at cross-purposes. The end result of any Kentucky hedging program should be one that provides long-term benefit to consumers and strikes the proper balance of rewards and penalties for the utility managing the hedging program.

(2) Utilities

(i) Define internally the objective of its hedging program, with consideration given to establishing a price-not-to-exceed level that is acceptable for customers.

Using Commission guidelines, utilities should be allowed to flexibly tailor the hedging programs to meet the individual needs of the utilities and their customers.

Financial hedging programs should be considered to augment traditional and less risky strategies, such as storage, GCA cost recovery, and budget billing, for mitigation of price volatility and price risk, while maintaining reliability of supply.

This step, which would be done by each individual utility, might require public meetings, focus group sessions, and/or statistical analysis of shut-offs or slow-pay practices relative to price levels and duration of certain price levels. Examination of historical pricing trends and behavior would certainly be required. If a price not-to-exceed objective is chosen, a starting point for utility discussion might be a not-to-exceed gas price defined by two standard deviations from the 5 year historical average of gas prices.

(ii) Develop the necessary analytical framework for implementing the chosen objective.

Personnel responsible for any hedging program must have access to such tools as the Black/Scholes model (an option pricing program), weather data and historical gas price data, technical pricing analysis tools, etc.

(iii) Implement the necessary controls as a foundation for the program.

Whenever significant dollars are exposed, necessary controls must be instated. Liberty recommends that hedging decisions be made through collective discussion of department heads and executives. Duplicate confirmations of all executed deals need to be immediately sent to at least one additional department (probably accounting) so there are no financial and accounting surprises. Risk management procedures need to be amended to specifically evaluate the level of exposure held by the company on any given day, including looking at liquidity concerns related to possible margin calls. Changing market conditions must be factored into the hedging plan on a regular basis, and the plan/model needs to be revised as necessary.

(iv) Recognize and plan for the administrative and financial support requirements associated with the development of any hedging program.

Database, software and hardware requirements may change in order to meet the real-time information needs of a hedging program. Employees with specialized skills may be required. Contracts may need to be signed with brokers, and procedures to enable smooth functioning of the hedging program need to be detailed. Accounting systems must be able to record transactions appropriately and to produce financial status reports on a regular basis.

Appropriate accounting guidelines (such as those embodied in FASB 133) should be considered in developing financial hedging programs.

(3) Overall Conclusions

Limited programs for the purpose of guarding against “price spikes” should be considered. The costs of such programs, i.e. insurance against unlikely but potentially significant events, should be recoverable from ratepayers, the beneficiaries of the programs. The costs of such limited programs should be relatively minimal. It is not anticipated that the LDCs would have to establish formal trading operations to accomplish these objectives.

D. GCA Mechanism, Budget Billing and the Uncollectibles Issue

1. Scope

This chapter discusses the Gas Cost Adjustment (GCA) Mechanism that governs how increases in natural gas prices at the wholesale level are passed along to the LDCs' retail customers. Higher gas prices, of course, present a burden for customers. Even if hedging could prevent higher prices, which it cannot, the higher levels of consumption that accompany a colder-than-normal winter (such as the winter of 2000/01) present customers with higher gas bills. Programs that help customers manage these higher gas bills, such as budget billing, are available in Kentucky. Liberty's study briefly addressed Kentucky budget billing programs, and our findings are presented in this chapter.

This chapter also addresses a consequence for the companies of higher gas bills, namely the increase in their uncollectibles expense. The companies reported to Liberty that, even after their best efforts at arranging community assistance for their customers, and doing all they could to facilitate bill payment through budget-billing programs, their uncollectibles expense rose significantly as a consequence of the extraordinarily high levels of gas costs during the winter of 2000/01.

2. The GCA Mechanism

The GCA Mechanism plays a role in smoothing out the variation that characterizes gas prices. Authorized initially to assist the companies in managing the cash-flow consequences of changes in gas costs, the GCA is also recognized as a means to reflect in retail prices a blend of the wholesale prices that occur over the annual cycles of the gas markets.

The chart on the next page (FigureI.D.1) shows how the mechanism functioned through the period leading up to, during and after the price spike that occurred during the winter of 2000/01. The chart shows the retail rates for small-volume customers, including both gas and non-gas costs, for the five LDCs. Some of the companies' base rates include cost components that are counted as gas costs for other companies (storage costs, in particular). Because of the difference in what is included in each company's gas costs, the companies' retail rates offer the best comparison.

Figure I.D.1
Kentucky Retail Gas Rates

Also plotted on the chart for purposes of comparison is the first-of-the-month Henry Hub price, taken from Figure I.B.1 in Chapter I.B of this report. The Henry Hub price is not comparable to the retail rates of the five LDCs. The Henry Hub price is a field-market price and thus includes no transportation charges or storage costs for moving gas to the LDCs' market areas, and does not include the LDCs' distribution charges that are intended to cover their costs of operation. The purpose of showing the Henry Hub price is to demonstrate how the pattern in wholesale prices compares to the pattern in retail prices through this period.

As is apparent from looking at the chart, the companies' retail prices generally postponed the peak in Henry Hub prices by three to five months, and attenuated it significantly. Even though the Commission required monthly (rather than quarterly) GCA filings for the first half of 2001, in an effort to pass along price declines promptly, the decline in the companies' retail rates did not occur until June of that year; more significant declines did not occur until July and August.

In general, whenever there is such an attenuation of a price spike in the natural gas business, it could raise issues for customers that have traditionally had the ability to switch from sales service to transportation service. Liberty notes that the attenuation of the price spike that occurred through the operation of the LDC's GCA mechanisms could have adverse consequences for small-volume customers. The problem is that, at any given time, there are customers who are considering switching from sales service, under which they buy their gas from the LDC, to transportation service, under which they buy their gas from a marketer, and have it delivered by the LDC.

Marketers can offer prospective customers a variety of gas-supply arrangements. These can range from sales service at the customer's location (analogous to the sales service provided by the LDC), to an agency-type arrangement, under which the marketer acts as the customer's agent. If the marketer acts as an agent for a customer, the marketer assumes responsibility for procuring gas in a field-market location, plus pipeline transportation of the gas to the city gate, and delivery of the gas by the LDC from the city gate to the customer's premises. The price to the customer can range from a field-market price, plus transportation and distribution charges, to an all-in price, under which the marketer buys and then re-sells to the customer at a price negotiated between them. A negotiated price could also include the effect of an agreed hedge, or other special features.

While the variety of arrangements available through third-party marketers is attractive, the LDC usually has an advantage if other factors are equal. Working with marketers generally involves at least some risk that the marketer will fail, resulting in the agreed upon gas supply not being available as required. Also, working with a third-party supplier generally involves more work for the customer, such as having to provide estimates of its requirements in advance, and then adjusting those estimates as its requirements change. The LDC, on the other hand, offers reliable, on-demand service, where the customer uses what it needs, and then is billed for what it uses. The extra risk and the extra work associated with marketers generally work to the LDC's benefit as long as the LDC's price is not much greater than the price offered by the marketers.

It is possible that the attenuating effect of the GCA mechanism could have cost some of the LDCs their inherent market advantage in the spring and summer of 2001. Allowing for the transportation and distribution mark-ups suggested by the data for 1999 in Figure I.D.1, there would have been a period of almost a year after January of 2001 when a marketer's price could have been below the LDC's price by up to $2.00 per MMBtu. Such a large differential for such an extended period may have been enough to induce some system-supply customers, who had been considering switching, to make the change.

Without properly constructed transportation services and programs, such switching could hurt small-volume customers, such as residential customers. The type of customer who would be considering switching is generally a commercial or industrial customer, who uses considerably more gas than a residential customer, but who is not large enough to have already been induced to switch. When the difference between the price of system supply and the price offered by marketers gets large enough, for a sufficiently long period of time, then the savings associated with switching gas suppliers becomes too great to ignore.

Switching hurts small-volume customers the most because the customer who switches probably has a higher load factor than the customers who remain. The effect of a high volume, high load factor customer switching and leaving system supply is that the LDCs transmission and distribution costs must now be spread over a smaller number of customers. This then increases the overall prices that the remaining customers must pay. In effect, the customer who switched had been subsidizing small-volume customers by purchasing from a supply portfolio that was more costly than one designed for its specific requirements. When the customer switches, that subsidy ends.

The competition between LDCs and marketers for commercial and industrial customers occurs continuously. Switching that occurs on the basis of genuine price signals is understandable and generally cannot be constrained. Trying to stop such switching can lead to bypass or conversion to alternate fuels, both of which are worse for small-volume customers than letting the larger-volume customers switch to transportation service. Although the LDCs did not report abnormally high numbers of customers switching to transportation service, our concern is that the attenuation of the wholesale price increase that was produced by the GCA mechanism may have induced some switching that would not otherwise have occurred. If even a small number of customers switched due to the attenuating effect of the GCA mechanism, such switching, which was to the detriment of system sales customers, was the result of inaccurate price signals rather than a genuine difference in costs. It would be more understandable if switching was due to some genuine difference in the costs that LDCs and third-party suppliers incur in providing service to customers.

It is tempting to argue that attenuation of the price increase was helpful to small-volume customers in managing their gas bills. It is possible, however, that the increase in units consumed during the cold winter of 2000/01 had a greater influence on that winter's gas bills than the mitigation of the price spike provided by the GCA mechanism. As discussed in the next sections of this chapter, budget billing and community assistance programs are the way to help customers manage their gas bills. These programs do not result in attenuation of a price increase.

Columbia of Kentucky's comments to the Commission in its March 30 Report in Case No. 384 identified an important question related to the price signals provided to customers:

> "Retail suppliers of natural gas, whether they are regulated LDCs, municipalities, marketers supplying industrial and large commercial customers, or marketers in Columbia's Choice program, are all buying gas on the wholesale market and passing these costs along to customers in the retail market. The question of how and when these costs are passed on to retail customers can be answered by first determining one's primary objective. Is sending an accurate and timely price signal the primary objective, or is smoothing out costs in a volatile market more desirable?" (March 30 Report at p. 21.)

Liberty shares the Commission's expressed interest in reducing volatility of gas prices, but Liberty believes that the GCA mechanism should produce a pricing pattern for system supply that reflects patterns in market prices as closely as possible, in order to avoid inducing "uneconomic" switching. Liberty observes that recent directions in energy utility pricing policy in the U. S. go toward charging the customer a price that reflects the cost of providing the service. The Commission's recent direction to the companies to use forecasted gas prices for the period that the GCA will be in effect in making GCA adjustments is a step in the right direction.

Other changes in the companies' GCA mechanisms, and in the Commission's consideration of proposed adjustments, may be possible. It occurs to Liberty, for example, that one possible change would be to have GCA filings made more often. This would only be attractive if the considerable volume of documentation required with the filings were allowed to be filed less often, perhaps once or twice a year, rather than with every GCA filing. Another example of a possible changed would be for all the LDCs to have provisions in their GCA clauses that provide for out-of-time or emergency filings that could be made with minimal documentation since the only changes requiring such filings would be changes in the commodity cost of gas. Although the magnitude and duration of the price spikes of 2000-2001, which give rise to our concern, are unprecedented, we recommend that the Commission and the parties review the various GCA mechanisms, for the purpose of ensuring that they do not produce prices that distort the competition between LDC system supply and alternative sources of gas.

3. Budget Billing

The Commission also addressed the subject of budget billing in its orders in Administrative Case No. 384. In its July 17, 2001, Order, the Commission required the companies to provide education and counseling on their budget billing plans to customers with chronic payment problems. The Order stated that,

> "… for customers that have chronic payment problems resulting in disconnections, the LDCs may consider putting the customer on notice that if the situation is repeated, the customer will be required to switch to budget billing

> unless the customer signs a form prepared by the LDC refusing the option." (July 17 Order, at p. 11.)

Two intervenors in the Commission's proceedings, Metro Human Needs Alliance (MHNA) and People Organized and Working for Energy Reform (POWER) expressed concern that implementation of the Commission's directives would result in delays in reconnection for customers whose service had been terminated for non-payment. In an order dated September 6, 2001, in the same proceeding, the Commission affirmed its earlier direction, in the hope that the required education would help avoid future disconnections.

In the course of this project, Liberty requested statistics from the companies on rates of participation in their respective budget billing programs. The chart on the next page (Figure I.D.2) presents a plot of the data that we received. (ULH&P did not provide statistics for 1999.)

Figure I.D.2
Budget Billing

Liberty has two observations from this information on budget billing program participation:

- All companies' participation rates increased over the period shown (1999-2001), probably due to the price increases of 2000/01 and by increased efforts of LDCs to make customers aware of budget billing options.
- Columbia of Kentucky is attaining participation rates that are over twice the participation rates of the other four Kentucky LDCs.

Liberty's limited questions to Columbia suggested to us that the Company was not aware that its participation rate was so much higher than the rates experienced by the other companies, nor did it have an explanation for the difference. Liberty's experience in this area suggests that the other companies' participation rates are typical of participation rates for most LDCs across the country. Therefore, the lower participation rates of the other four LDCs, when compared to Columbia, does not indicate a lack of emphasis or effort on the part of the other four LDCs.

Liberty did not have time to explore these observations further as part of this project. Liberty observes that Columbia's percentage of residential customers terminated due to non-payment is not lower than the other companies (see Figure I.B.2 in Chapter I.B of this report), and that its uncollectibles experience does not appear to be different from the others (see Figure I.B.3 in Chapter I.B). Liberty suggests that the Commission and the parties pursue the details of Columbia's experience in these areas, in an effort to determine how the companies can best assist their customers in managing their gas bills.

4. The Uncollectibles Issue

In Chapter I.B of this report, Liberty discussed the fact that the uncollectibles issue was becoming increasingly important to all of the Kentucky LDCs. In the course of Liberty's interviews for this audit, several of the LDCs raised an issue that the Commission may need to address. Western Kentucky Gas (WKG) was particularly concerned about this issue. Figure I.B.3 explains why WKG had a higher level of concern. It experienced a significantly higher level of uncollectibles expense during 2000 and 2001 than any of the other four LDCs. While uncollectibles expense probably went back down in the winter just ended (along with the price of gas and the number of degree-days), WKG suggests that, in an era of increased cost volatility, gas costs have become an important factor in the level of uncollectibles expense. Because of that linkage, WKG suggests a fresh look at the rate treatment for uncollectibles expense.

While many of the thoughts expressed in the following discussion relate to those expressed by WKG, Liberty is presenting them here because recovery of uncollectibles expense in rates is an issue for all of the Kentucky LDCs, and any action taken by the Commission on this subject would logically impact all LDCs.

Historically, uncollectibles expense has been a <u>non</u>-gas-cost item in the Kentucky LDCs' rate structures. The typical treatment has been to include an allowance for uncollectibles expense in a company's revenue requirement (*i.e.*, the cost basis for the determination of a company's base rates). The uncollectibles allowance has been based on a company's collections experience. Including the allowance in base rates provided the company with an incentive to maintain or even improve its collections, as any reductions (or improvements) in collections would translate into reduced (or increased) profits.

When gas prices and/or the number of degree-days go up, however, uncollectibles expense is likely to increase in response to factors that a company can do little about. These factors include:

- Increased gas bills require a larger share of the resources of low- and fixed-income customers, resulting in their reaching the limits of their ability to pay sooner than when bills are low.

- The resources available to programs of assistance for low- and fixed-income customers with expenses such as utility bills tend to be fixed (or to decline) over time. When bills go up, the available assistance runs out sooner.

- Many States have winter-period limits on companies' ability to terminate service for non-payment. (These limits are sometimes referred to as "cold-weather rules".) A consequence of these limits is that companies cannot use service terminations to keep uncollectibles expense from growing once the weather gets cold.

While these factors are largely beyond a company's control, their consequences are felt by the company. Any change in uncollectibles expense, up or down, goes straight to "the bottom line". Profits increase if uncollectibles falls, and profits decrease if uncollectibles rises. Since the uncollectibles impact on WKG was the greatest, the following puts the magnitude of this matter into perspective. WKG's Net Income (after taxes and interest expense) in the year 2000 was reported as $7.9 million. The same source lists $4.8 million as the allowance for Uncollectible Accounts in 2000; this was the actual amount uncollected in the year 2000. However, one year earlier in its last rate case (Case No. 99-070), the Company proposed an allowance for uncollectibles of $0.6 million, or $4.2 million less than what the actual uncollectibles turned out to be in the year 2000. Liberty notes that WKG's proposed Net Income in Case No. 99-070 was slightly more than $8.0 million, based on a requested increase of $14.1 million. WKG received a $9.9 million increase in that case under a unanimous settlement agreement. The fact that WKG's 2000 Net Income was $7.9 million, even with the increase in its uncollectibles and without getting all it asked for in its rate case, suggests that the agreed-upon rate increase was adequate and/or other factors (weather-sensitive sales, possibly) effectively offset the increase in its uncollectibles.

The approach suggested by WKG in our interview is to make uncollectibles expense a gas-cost item, rather than a non-gas-cost item. Gas-cost expenses are flowed into companies' GCA charges in the same amounts as they are incurred. Expenses are reconciled with charges ("trued up") to ensure that cost recovery is complete. The problem associated with uncollectibles is that currently the true-up matches gas costs incurred with gas costs billed, not with collections, which recently have been much lower than costs billed due to uncollectibles. Currently, the actual uncollectibles expense is not reconciled with the allowance for uncollectibles that is included in base rates. In other words, there is no provision for the LDC to recover any more, or any less, of the uncollectibles than has been provided for in the non-gas cost portion of rates.

WKG's suggestion, to move uncollectibles from non-gas costs to gas costs, would make uncollectibles part of the true-up process. While Liberty did not go into detail when we discussed this with WKG, it is easy to envision a process whereby an amount for uncollectibles would be determined at a particular point in the GCA cycle (at the end of August, for example) and then that amount would be added to the costs to be recovered through the GCA in the next cycle. With this change, the companies would recover their uncollectibles expense whether the amount is high, as will likely be the case when the weather is cold and costs are high, or low, as was the case in 1999 (which was one of the warmest years on record).

This solution is particularly compelling to WKG, as so much of its charges are gas costs. Western's volumetric rate (residential) was about 80 percent gas cost in July 2000, before prices had run up, and nearly 90 percent gas costs in February 2001, when the big "wave" of gas costs was working its way through the GCA mechanism. Having such a large proportion of total rates (gas costs plus base rate costs) represented by gas costs means that when uncollectibles increase, they represent an increase on a very big number. WKG reports that at least one State (Virginia) has approached another of Atmos's divisions regarding this change. WKG also reports that Massachusetts has a change under consideration in this area.

WKG's suggestion is appealing because of its simplicity. That very simplicity is also a reason for concern, however. Dealing with customers' ability (or inability) to pay their utility bills is a complex subject involving different programs, different interests, and a complex set of influences and incentives. Each of these factors is interwoven with other factors, and one factor cannot be justifiably adjusted in isolation. A list of those programs, interests and incentives could include the following:

- Programs:
    - Low-income heating-assistance programs such as LIHEAP, and perhaps other welfare programs, and
    - Budget billing
    - Special customer aggregation programs for low-income customer groups in the case where the LDC already has a retail unbundling program;

- Interests:
    - System-supply customers, primarily residential and small-volume commercial and industrial customers;
    - Company shareholders;
    - Community support groups, both those involved in welfare programs, and those who might organize a low-income-customer aggregation program in the case where the LDC already has a retail unbundling program;

- Influences and incentives:
    - "Cold-weather" rules; *i.e.*, PSC policies regarding termination of service for non-payment;
    - Price elasticity considerations, including
        - Does adding more cost for recovery through the GCA mechanism cause more customers to abandon natural gas for an alternate fuel?
        - Does adding more cost to the GCA cause customers to switch to an alternate gas supplier, such as a broker?

      Both of these effects would likely tend to compound the problem.
    - Would companies curtail their collection efforts if recovery of uncollectibles expense was assured?

Public utility commissions traditionally use estimates for <u>all</u> categories of revenue and expense in setting (non-gas) rates, and refrain from adjusting rates in response to changes in any one cost or revenue component. The latter type of adjustment is sometimes referred to as "single-issue ratemaking", and is prohibited by statute in some States. The reason is that, just as WKG's uncollectibles expense in 2000 was higher than the allowance in its last rate case, other expenses may have been lower than their respective allowances, or revenues may have been higher. Thus, while individual categories may have been off their estimates, the overall result, manifested in the Company's realized rate of return, may have been near the result intended when the PSC set the Company's rates.

Liberty's assessment is that WKG has a point regarding the consequences of gas-price volatility for cost recovery. Our concern is that application of a "quick fix" could result in possible inequities or unintended outcomes. While comprehensive investigation is the enemy of prompt action, we believe that this subject requires a broader review than can (or should) be accomplished in this audit. Our suggestion is that the discussion we recommended in the previous section of this chapter, regarding a program to better understand the companies' experiences with their budget billing programs, be expanded to encompass the issues raised here. The expanded approach should also address the broader range of influences and incentives affecting the uncollectibles issue.

E. Background on Forecasting

1. Scope

This chapter of Liberty's report addresses the background issues surrounding natural gas forecasting, with the purpose of identifying optimum planning objectives and programs and integration of these plans and programs.

In addition to providing general background on forecasting, this chapter also discusses findings related to the five Kentucky LDCs in a general way. Some comparisons are made, where such comparisons are illustrative of the different ways in which the LDCs might approach a specific forecasting issue. In each case, however, more detailed discussion of these same issues will be found in Section III, Company-by-Company Reports, where specific issues related to each of the LDCs are examined.

This chapter is organized into the following three sections, and their sub-sections, as follows:

- **Forecasting Components (peak day and general):**

  a. Weather Variation Forecasting
  b. Short-Term Weather Forecast Variation
  c. Number of Customers
  d. Usage Per Customer (Base/Heat factors)
  e. Demand

- **Supply Planning – General Comments on Gas Cost Analysis for 2000-01**

- **General Guidelines on Forecasting and Supply Capacity Planning**

2. Forecasting Components (peak day and general):

The prediction of natural gas requirements is a function of how many customers will use the commodity, and how much each one will use. Although some customers may use relatively stable volumes for industrial process applications, others may need gas for space heating, which means trying to predict the weather, a notoriously unrewarding task. The importance of accurate forecasts ties directly to the ratepayer – if a utility over-estimates demand, the ratepayer is charged for gas-supply capacity that is not needed; if a utility under-estimates requirements, it may not be able to serve some of its customers, or may serve them only at extremely high costs.

Throughout this section, reference will be made to Monte Carlo simulation. This technique repeatedly (hundreds or thousands of times) randomly generates values for uncertain variables with a known range to simulate a model. Monte Carlo simulation was named for the casinos in Monte Carlo, Monaco. Games of chance – roulette, dice, slot machines – exhibit random behavior. This is similar to how Monte Carlo simulation selects values at random to simulate a model. A die will produce a 1, 2, 3, 4, 5 or 6 – but which value will be produced for any given roll is unknown. Variables with a known range of values – weather and associated heating degree days, for example – but with an uncertain value for any particular time or event – a day in January, for example – will be repeatedly plugged into the equation until a model is developed. Liberty suggests that the utilities that do not currently use Monte Carlo simulation consider whether these types of analyses may be useful to help refine their forecasting efforts.

a. Weather Variation Forecasting

A sound analysis of historical weather is fundamental to gas-supply planning. The weather for a day in January is influenced by what typical January weather is like, and is influenced even more by the previous day's weather. There is always the possibility of a record-breaking high or low temperature, however. Finally, weather can vary across a service territory; each of the LDCs that are the subjects of this study has identified weather stations that approximate the weather for its customer base.

The five Kentucky LDCs use the following weather stations for demand forecasting:

Columbia: Lexington Bluegrass Airport
Huntington Tri-State Airport

Delta: Lexington Bluegrass Airport
Berea College
Farmers, KY
Barbourville, KY
London, KY
Manchester, KY
Williamsburg, KY

LG&E: Louisville Standiford Airport

ULH&P: Cincinnati Northern Kentucky Airport

Western: Paducah Barkley Regional Airport (Texas Gas Zone 2)
Evansville Regional Airport (Texas Gas Zone 3)
Louisville Standiford Airport (Texas Gas Zone 4)
Lexington Bluegrass Airport (Tennessee Gas Pipeline service area)

Over 50 years of weather data is available from the National Climatic Data Center (NCDC) of the National Oceanic and Atmospheric Administration (NOAA) for each of the above weather stations except for Huntington, for which there is only 40 years of data, and the subsidiary locations (locations other than Lexington Airport) used by Delta. Liberty obtained the NCDC data for the airport weather stations. The data obtained was daily temperature data, indicating maximums and minimums for each of the indicated weather stations. Liberty then constructed the following tables, based on this NCDC temperature data. As a result of Liberty's calculations, monthly heating degree-days (HDD) for each of these weather stations are distributed as follows:

122738	EVANSVILLE REGIONAL AP											
Month:	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***Annual***
Std.Dev	169	142	155	84	47	7	1	3	28	88	124	198	360
Min	704	578	0	0	0	0	0	0	0	0	0	0	3916
-2 std	692	538	301	119	0	0	0	0	0	77	328	494	3935
Avg	**1030**	**823**	**611**	**287**	**82**	**6**	**0**	**1**	**44**	**253**	**577**	**890**	**4655**
+2 std	1369	1107	921	455	175	20	2	7	101	429	826	1287	5375
Max	1556	1234	1082	437	194	31	3	16	127	431	791	1308	5485
Case:	1556	1182	750	230	136	0	0	0	12	319	462	837	**5485**

151855	CINCINNATI NORTHERN KY AP											
Month:	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***Annual***
Std.Dev	175	146	151	93	63	16	1	5	34	101	130	198	389
Min	735	659	0	0	0	0	0	0	0	0	0	0	4235
-2 std	745	601	387	173	1	0	0	0	0	101	359	531	4406
Avg	**1095**	**893**	**689**	**359**	**128**	**17**	**1**	**3**	**66**	**304**	**619**	**928**	**5184**
+2 std	1444	1186	991	545	255	50	3	13	135	507	878	1325	5962
Max	1645	1312	1098	517	258	83	6	22	152	519	903	1346	6087
Case:	1645	1256	850	337	203	10	0	0	21	371	535	861	**6087**

154746	LEXINGTON BLUEGRASS AP											
Month:	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***Annual***
Std.Dev	171	136	152	90	59	12	2	3	31	96	128	188	336
Min	663	612	0	0	0	0	0	0	0	0	0	0	3966
-2 std	675	560	329	137	0	0	0	0	0	78	326	497	4085
Avg	**1017**	**832**	**632**	**318**	**109**	**12**	**0**	**2**	**51**	**270**	**581**	**873**	**4757**
+2 std	1360	1104	935	499	227	36	4	9	113	461	837	1249	5428
Max	1464	1224	1097	499	240	49	10	16	131	482	836	1303	5499
Case:	1464	1189	741	251	182	6	0	0	21	344	483	816	**5499**

154954	LOUISVILLE STANDIFORD FIELD											
Month:	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***Annual***
Std.Dev	167	136	143	86	49	8	0	2	28	85	123	190	364
Min	640	570	0	0	0	0	0	0	0	0	0	0	3439
-2 std	649	513	299	101	0	0	0	0	0	68	293	462	3720
Avg	**982**	**785**	**585**	**273**	**81**	**7**	**0**	**1**	**37**	**239**	**540**	**843**	**4447**
+2 std	1316	1056	871	445	180	23	0	4	92	410	786	1223	5175
Max	1441	1153	1012	485	198	31	1	12	126	418	769	1230	5087
Case:	1441	1111	698	220	141	1	0	0	4	290	434	746	**5087**

156110	PADUCAH BARKLEY REGIONAL AP											
Month:	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***Annual***
Std.Dev	159	134	151	83	39	5	0	2	24	82	124	187	324
Min	659	536	0	0	0	0	0	0	0	0	0	0	3518
-2 std	644	488	254	78	0	0	0	0	0	59	281	459	3625
Avg	**962**	**756**	**556**	**245**	**65**	**3**	**0**	**1**	**37**	**222**	**529**	**834**	**4273**
+2 std	1280	1025	858	412	143	13	1	4	85	386	778	1208	4921

Max	1403	1136	997	416	151	20	2	9	102	391	754	1213	4927
Case:	1403	1097	665	169	94	0	0	0	4	268	415	813	**4927**

464393	HUNTINGTON TRI-STATE ARPT												
Month:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Annual**
Std.Dev	161	135	144	86	59	13	3	5	31	99	130	202	346
Min	711	542	0	0	0	0	0	0	0	0	0	0	3681
-2 std	693	542	299	131	0	0	0	0	0	86	290	437	3976
Avg	**1016**	**813**	**586**	**303**	**111**	**15**	**1**	**3**	**60**	**284**	**549**	**841**	**4668**
+2 std	1338	1084	873	474	228	42	7	13	122	481	809	1244	5360
Max	1404	1129	818	459	219	60	10	20	126	493	774	1231	5223
Case:	1404	1082	674	249	162	12	0	0	15	328	489	789	**5205**

A heating degree day – HDD – is a measure of each day's temperatures and is broadly used to relate temperature to the demand for temperature-sensitive consumption of natural gas. Heating degree days for a particular day (midnight to midnight) are calculated in these tables by adding the day's high and low temperatures and dividing by two. If the number is above 65, there are no heating degree days that day. If the number is less than 65, subtract it from 65 to find the number of heating degree days. For example, if the day's high temperature is 60 and the low is 40, the average temperature is 50 degrees. 65 minus 50 equates to 15 heating degree days.

The statistics in these tables were calculated by Liberty on a calendar-month basis, with columns representing January through December. The rows indicate average HDD for each month, plus the standard deviation, minimum and maximum monthly HDD, and plus or minus two standard deviations around the average. The "Annual" column is not the summation of the associated row; rather, it indicates the variation in annual HDD for the years for which data is available. The annual HDD for each year with 12 months of observations were summed and then divided by the number of years to determine the annual average number. The minimum and maximum annual HDD for those years are also indicated, and the standard deviation is calculated based on the annual figures.

The 'Case' line in each table is a combination of the maximum HDD that occurred in January of any year, along with a distribution of the total annual HDD that occurred in 1978, which is the coldest-weather year in the data set. It is this scenario, with the coldest month (January) and the maximum annual degree days (the coldest calendar year), against which Liberty evaluated the LDCs' capacity portfolios.

Liberty's purpose in conducting this weather analysis, rather than those provided by the companies in response to Liberty's data requests, was two-fold:

- To indicate the variation in HDD experienced between weather stations in the region; and
- To avoid any data inconsistencies that could result from using weather data provided by the companies. Such inconsistencies could arise due to differences in the method for computing HDD (such as (daily min+daily max)/2 vs. hourly average), or differences in the weather-station choices or weather-data sources.

Liberty feels that weather analysis is a very important component of LDC gas-requirements forecasting, and is crucial in determining the following two elements of a natural gas forecast:

- The peak day forecast, and
- The total annual sendout.

Therefore, a sound weather analysis is the starting point for the justification of natural gas resources that will be needed to serve demand for natural gas on each LDC's system.

Finding 1: There are significant differences between weather stations that warrant and justify the use of different weather stations in the calculation of demand for companies with wide service territories, such as Western and Columbia.

If weather were normally distributed (which it is not), statistical theory tells us that the values shown in the rows between the minimum and the maximum should be ordered, with the minimum and maximum very close to the plus-or-minus-two standard deviation figures; statistical theory says that this would correspond to a 95-percent confidence level for the distribution. Since there are 40 to 50 years of data, a 2.5 percent temperature extreme on one side of the distribution would correspond to 50 times 2.5 percent, or approximately one annual observation on each side of the distribution outside of the 95-percent band.

Finding 2: The weather distributions for Louisville and Huntington are quite skewed. The difference between the minimum and the average is about 1000 HDD, while the difference between the average and the maximum is about 600 HDD. Therefore, any assumptions and analysis regarding weather sensitivity and demand forecasting should incorporate this feature.

In our experience, a Monte Carlo simulation is the most effective way to model and determine a probability distribution for weather. Assuming weather temperature follows a continuous distribution with an infinite range, there is always a probability that a new observation (i.e. total annual temperature of HDDs) will fall above or below what has been historically observed. It is the objective of a Monte Carlo weather simulation to generate a distribution that is representative of the full distribution including the unobserved "tails" of the distribution that would otherwise be ignored by basing decisions on historical observations alone.

Hence, the Monte Carlo simulation allows modeling of tail (extreme) distribution probabilities in order to quantify probabilities of various levels of annual HDD that are built into any natural gas procurement plan. For example, of particular interest would be the probability of experiencing extremely cold weather, with temperatures occurring that had not been previously observed.

An important question is what weather pattern(s) a utility should plan for. Most utilities, as is the case with most of the utilities in this audit, have relied on extreme weather actually observed.

This method is commonly preferred, both for peak-day-sendout planning purposes and annual-sendout planning. However, this method may not reflect two important points:

- The aforementioned difference between the distribution of observed weather and the distribution of what weather could be (*i.e.,* the "tail" of potential but not yet experienced possibilities on either side of the probability distribution.)
- The economic trade-off between providing firm contracted gas supply and the cost of obtaining incremental gas supplies under extreme weather conditions.

Liberty does not suggest that interruption of high-priority residential and space-heating customers be considered as an alternative for the purpose of estimating an optimal capacity portfolio. Rather, Liberty's point is that, in today's gas market, every company has supply alternatives, even under the most extreme weather conditions. Our recommendation is that, as part of its supply planning, each company should identify those alternatives, assess their potential costs, and develop its supply plans accordingly. We expect that, in virtually every case, there would be an analytically-derived cut-off point for the contract and on-system portfolio, and one or more alternatives for extreme weather conditions (*i.e.*, HDDs in excess of the chosen percentiles) that would be more cost-effective than holding firm contracts for those conditions.

Finding 3: Only ULH&P indicated that it has conducted a study to determine the 'optimal' cutoff point for peak weather purposes. All other companies have picked one or a combination of historical extreme weather cases as a basis for gas-supply planning.

The following table contains the number of days colder than a given number of HDD (the left-hand column) for each of the weather stations examined in this chapter:

	Evansville	Cincinnati	Lexington	Louisville	Paducah	Huntington
Data days	19612	19687	19707	19649	19123	14838
Data yrs	54	54	54	54	52	41
Days>=80	0	0	0	0	0	0
Days>=79	0	0	0	0	0	0
Days>=78	0	0	0	0	0	0
Days>=77	0	3	0	0	0	0
Days>=76	0	4	0	0	0	0
Days>=75	0	5	0	0	0	0
Days>=74	2	6	2	0	0	0
Days>=73	3	8	4	1	0	0
Days>=72	3	10	4	2	1	1
Days>=71	6	10	5	4	1	1
Days>=70	9	12	6	5	1	2
Days>=69	9	15	8	7	1	5
Days>=68	11	17	10	8	3	8
Days>=67	14	23	13	8	3	10

Days>=66	17	25	18	12	5	10
Days>=65	23	27	21	13	9	12

Note that there are no observations with more than 77 HDD for any of the stations. These observations can be translated into percentages by dividing the number of days by the number of years. Although this analysis doesn't take into account coldest days that take place during the same year, it is a good-enough proxy for understanding the probability of a cold day occurring within a given year, where a cold day is defined as having more than a specified number of HDD.

The following table converts the HDD data from the table immediately above to a display of the probability of a cold day occurring within a given year.

	Evansville	**Cincinnati**	**Lexington**	**Louisville**	**Paducah**	**Huntington**
Prob >80:	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Prob >77:	0.00%	5.56%	0.00%	0.00%	0.00%	0.00%
Prob >75:	0.00%	9.27%	0.00%	0.00%	0.00%	0.00%
Prob >70:	16.75%	22.25%	11.11%	9.29%	1.91%	4.92%
Prob >65:	42.81%	50.06%	38.89%	24.15%	17.18%	29.52%

This table shows that at Cincinnati, for example, there have been three days with more than 77 HDD, which corresponds to a probability of 3/54 = 5.6 percent. Given this information and the fact that ULH&P's analysis of the 'optimal' design-day conditions indicated 97 percent as the planning cut-off, it is appropriate for ULH&P to select 77 HDD for its design day. None of the other four LDCs used such an approach in the weather analysis built into their natural gas procurement planning.

Finding 4: If we were to assume the same 97-percent planning criterion (i.e. two days greater than the specified HDD) for all other utilities, Liberty finds the design criteria for the other weather stations to be as shown in the following table. The design criterion actually used by each of the five LDCs as the basis for their gas-supply contracting is also shown.

LDC	**Weather Station For LDC Analysis**	**Liberty Calculated HDD**	**LDC Planning HDD (Design Criteria)**	**Notes**
Columbia	Lexington	74	70	
	Huntington	70	66	
Delta	Lexington	74	80	for North System
			77	for South System
LG&E	Louisville	72	77	

ULH&P	Cincinnati	77	77	
Western	Paducah	68	65	for entire system
	Evansville	74		
	Louisville	72		
	Lexington	74		

Examination of this information suggests that some of the LDCs are somewhat conservative, and others are less conservative, with respect to the peak-day assumption used for their gas-supply planning. Detailed discussion and analysis of the weather-related strategies for each of the LDCs are contained in the company-specific chapters found in Section III of this report.

Liberty is aware that some of the LDCs use methods for calculating HDDs that are different from the one that we used. For example, some companies use the average of 24 hourly observations of temperature, rather than the average of maximum and minimum temperatures within a day, to compare to 65 degrees. Moreover, some companies determine HDDs for the gas day, which is 10 a.m. to 10 a.m., rather than the calendar day (midnight to midnight). These differences may yield HDD data that are different from that in the tables above. Thus, the probability distribution that we constructed could be different from a probability distribution constructed from data collected by the company.

Liberty has not tried to compare HDD data constructed in the different ways to each other. As will be apparent from the previous discussion, however, Liberty's purpose is not to argue about the appropriate method for determining HDD, but to identify a readily-available source of weather data for use in constructing probability distributions. If companies have been collecting their own HDD data in a consistent way for 40 or 50 years, then their own data can serve the purpose. Alternatively, while hourly weather data for each station may not be as readily available as the daily data that we used, it may be available upon special request to the NCDC, or to an individual weather station. Our inquiries to the NCDC suggest that hourly data is available on a compact disk for all of the weather stations of interest for this study back to 1990, and is similarly available for some stations as far back as 1961. Moreover, individual weather stations (the Louisville airport, for example) have probably been collecting hourly data for an even longer period; the issue is finding the data and obtaining access to it. Finally, if careful comparisons are made over the period when both min/max and hourly data are readily available (the period since 1990, at least) between HDD calculated with "max plus min over two" and HDD calculated with the average of 24 hourly observations, it may turn out that the HDD distributions computed in the two different ways are either essentially identical, or that they vary in a systematic way that can be accommodated with an adjustment.

b. Short-Term Weather Forecast Variation

In addition to using historical weather data as part of the planning for gas procurement, utilities usually also purchase weather-forecasting services to help with prediction of the short-term daily sendout for the upcoming days. Each day, the gas control function at the LDC makes use of this short-term data; it is often updated throughout the day as temperature changes occur that are beyond a certain bandwidth around the predicted temperature. Liberty's interviews with gas control personnel indicated that the difference between historical weather used in planning and these short-term forecasts can be as much as 10 degrees. While this forecast variation is handled mostly through hourly gas-balancing flexibility, the short-term weather forecast often contains a bias towards 'normal' weather.

The weather-forecasting variation is important to consider because it can come into play when there is a third-party provider that is going to provide gas to the system on a daily forecasted basis, such as through a customer-choice program. Typically, an early-morning prediction of weather for the day is used to tell third-party providers to deliver specific amounts of gas. It will be the utility's responsibility to "balance" the difference between what is provided and what is actually demanded.

Finding 5: All utilities except for Delta use weather-forecasting services for calculating daily sendout estimates.

Finding 6: Utilities using weather-forecasting services also have a model to estimate daily sendout based on the short-term temperature forecast, and use this model on a daily basis. However, few of the utilities have incorporated weather-forecasting errors into the analytical component of the gas-supply plan, in terms of acquiring resources that allow modification of supply to meet such short-term variations, or the bias involved in weather forecasting.

Detailed discussion and analysis of the weather-related strategies for each of the LDCs is contained in the company-specific chapters found in Section III of this report.

c. Number of Customers

Just as with any other variable, the number of customers for each utility changes over time as new customers are added and some customers are no longer served. Therefore, it may be appropriate to incorporate the number of customers as a probability distribution within the natural gas demand forecast. Liberty observed that the LDCs used a variety of techniques in their gas supply planning to address the issue of number of customers.

Finding 7: Western and Delta incorporate the number of customers into the demand forecast as a fixed percentage increase for each rate class. ULH&P calculates customer saturation figures. Columbia goes further and splits rate classes into groups based on house type for residential customers and new, existing or conversion for commercial customers, which is a comprehensive model for the number of customers including economic variables such as housing starts. LG&E generates sendout forecasts using monthly sendout equations

that reflect a forecast of the number of customers based on forecasted demographic and economic activity.

Finding 8: None of the utilities make the estimation error in the customer forecast a part of the general forecasting error. ULH&P uses a Monte Carlo simulation based on historical sendout that incorporates variation in overall sendout.

Detailed discussion and analysis of the customer-related strategies for each of the LDCs is contained in the company-specific chapters found in Section III of this report.

d. Usage Per Customer (Base/Heat factors per customer)

The main reasons to deal with usage per customer as a separate component of gas supply forecasting is to have a comparison across rate classes; to monitor changes over time due to various factors, such as weather, seasons, conservation etc.; and to have a comparison among utilities when necessary.

Finding 9: While all of the utilities incorporate usage per customer in their forecasting, none of them make the estimation error in weather-normalized usage per customer a part of the overall forecast. While it is most likely the case that usage per customer is constant for large rate classes (with many customers), it may change in customer classes with a low number of customers and/or high usage per customer groups such as commercial rate classes.

Detailed discussion and analysis of the usage per customer-related strategies for each of the LDCs is contained in the company-specific chapters found in Section III of this report.

e. Demand

Finally, demand for natural gas – the ultimate goal of the forecasting process - can be estimated using various methods. Given inputs from the steps discussed above, one can multiply the customer figures with usage per customer (in the form of base/use factors) to obtain total usage, and multiply by HDD from different weather scenarios. Ideally, one can create a Monte Carlo simulation to incorporate all components, incorporating the estimation error of each step and resulting in a statistical estimation of the quantities of gas to be provided over time (sendout) and its potential variation.

Finding 10: None of the utilities, with the exception of ULH&P and LG&E, make the estimation error in the demand forecast a part of the overall gas supply planning methodology.

Finding 11: The HDDs assumed on a peak-day basis and on an annual basis by each utility varies by assumptions. Similarly, the HDDs assumed on an annual basis vary from company to company, with only LG&E and Columbia analyzing specific annual HDD weather scenarios.

Detailed discussion and analysis of the demand-related strategies for each of the LDCs is contained in the company-specific chapters found in Section III of this report.

3. Supply Planning – General Comments on Gas Cost Analysis for 2000-01

Historically, gas prices have shown stability for the most part. Over about the last ten years (more precisely, November 1993 to the present), there have been three periods when gas prices have gone above $4.00 per MMBtu. These periods occurred in the heating seasons of 1995-96, 1996-97, and 2000-01.

Liberty has calculated that the average price of gas over the last ten years has been $2.67 per MMBtu, with a standard deviation of $1.31. During this entire ten-year period, there were only 91 days (85 days for 2000/2001 alone) when the price of gas exceeded the average price plus two standard deviations, $5.30 per MMBtu. Statistically, this means that 95 percent of the time the price of gas was $5.30 or less, assuming that the occurrence of any given gas price is normally distributed. The number of days when the price of gas exceeded $6.00 per MMBtu was 53 (49 days for 2000/2001 alone).

It is interesting to note the differences in the price "spikes" for each of these three price-spike periods. The price increase of 2000/01 extended over a number of months, beginning in April 2000 and continuing through the summer of 2001. The character of the other two price spikes was very different: the spikes were confined to the heating season, with prices returning to below-average levels at the end of the heating season.

This discussion suggests the need to optimize the development and use of storage inventories in order to have moderately-priced gas available to meet annual and peak design-day sendout.

Finding 12: Part of the differences among the retail prices charged by the five LDCs during the winter of 2000/01 was the proportion of storage in their gas-supply mix, and the timing of the use of gas available from storage. One strategy to mitigate price spikes is to acquire additional storage capacity, and to maintain inventories of stored gas until the point in the heating season when the risk of gas-price spikes has declined.

Finding 13: None of the companies has conducted a cost/benefit analysis to compare the option of buying additional gas during peak periods to options that would enable keeping more storage inventory during the heating season (including both increasing the storage capacity available – through additional contracts

or additional on-system storage development – and, as possible, maintaining higher inventory levels within existing capacity further into the heating season). The benefit of such a strategy would be measured in terms of minimizing gas purchases during price spikes, versus extra costs associated with holding additional storage capacity and/or storage inventory.

4. General Guidelines on Forecasting and Supply Capacity Planning

Forecasting, which is an integral part of gas-supply planning, is not an exact science. By its nature, actual quantities of natural gas provided to meet demand have only a very small chance of matching a particular forecast. Therefore, assessing forecasting error may be important.

If natural gas demand had a known statistical distribution, such as a standard normal distribution, then only two variables would be necessary to model it: the average and its standard deviation. In the case of more complex distributions, the number of variables required to model them is larger. To avoid error caused by assuming an incorrect distribution for weather, one alternative is to run a Monte Carlo simulation. Such a simulation incorporates variation components from each of the forecast elements including weather, the number of customers, and the usage per customer. Such a simulation also incorporates any known bias, such as weather-forecasting bias, that may be present in a same-day weather forecast.

Liberty suggests, therefore, the following guidelines for each of the separate components of gas-supply forecasting. Liberty understands that all Kentucky LDCs will not find it necessary to implement all of the following guidelines. The guidelines are presented more as a listing of desirable forecasting techniques for consideration by each of the LDCs as ways in which forecasting improvements might be made. After such consideration, Liberty would anticipate implementation of some of these guidelines as appropriate, given the different circumstances of each of the LDCs.

a. Weather Variation Forecasting

- In most cases, it is natural to assume a symmetric weather distribution, which would justify a simplified weather analysis consisting only of a mean and a standard deviation. However, as the weather data from the stations at Louisville and Huntington indicate, the distribution can be significantly skewed. In these cases, representing variation with a simple standard deviation is not appropriate; a Monte Carlo weather analysis may be used to determine the extent of upside and downside swing that gas demand can experience for a given day, month or year.

  Therefore, all Kentucky LDCs should consider making such analyses part of their normal gas-supply planning.

- Most weather stations provide up to 100 years of historical weather data. However, it is known that year after year many new high and low average temperatures are observed on a daily, monthly or annual basis. Therefore, any given existing set of data is only a sample of the actual weather distribution. If planning is based solely on a selection of historical weather occurrences, it will inherently ignore the probability of record high or record low temperatures occurring. To properly evaluate the probability of occurrence of record weather, a Monte Carlo analysis may be used.

Therefore, all Kentucky LDCs should consider including an evaluation of possible extreme weather as part of their gas-supply planning.

- The limited analysis presented above regarding weather ignores any tradeoff between the expected costs of unmet demand (as indicated by extreme weather probabilities) versus the cost of contracting for additional resources within gas supply planning. Most gas supply plans are designed to meet design-day conditions and cold-weather scenarios that are derived from historical weather. Therefore, any justification of assumed design-day conditions and cold-weather scenarios should include a cost-tradeoff analysis that compares the costs of unmet demand (*e.g.*, the opportunity costs associated with curtailing service to high-margin interruptible customers) versus the cost of contracting for additional gas resources.

  Therefore all Kentucky LDCs should consider including cost/benefit analyses in the various weather scenarios used as part of their gas-supply planning.

- The degree of variation in each of the forecasting components, namely weather, number of customers and usage per customer, determines the order of importance of analyzing each component in more detail. Generally speaking, the highest degree of variation will be due to weather, the second-highest due to variation in the number of customers, and the third-highest will be due to variation in usage per customer. (Obviously, there are many factors that can change this ordering for a particular utility.)

  Therefore all Kentucky LDCs should evaluate this ranking and consider expending the necessary effort on in-depth evaluation studies of weather impacts, weather being the primary source of demand variation for all Kentucky utilities.

- On the subject of short-term weather forecasting, any bias (not variation) present in weather forecasting services is usually a small component compared to the variation in the weather forecast. Weather forecasts tend to have a bias towards normal weather when forecasts are compared to weather actually experienced. Evaluation of such bias is a lower priority than the evaluation of the three main components, namely weather, number of customers and usage per customer.

  Therefore all Kentucky LDCs should consider these priorities when making forecasting decisions related to procurement of natural gas supplies.

- Variations in short-term weather forecasting can influence gas deliverability and should be considered in the gas-supply planning process. This should be in the form of additional flexibility provided by gas-supply resources (suppliers, pipelines, storage at hand). The degree of change attributed to short-term weather forecasting would require a utility to increase deliverability on existing resources and/or to make spot purchases for additional gas.

Therefore, all Kentucky LDCs should consider incorporating the variation in short-term weather forecasting in the gas-supply planning process.

- All Kentucky LDCs should be able to outline and justify any weather assumptions they make regarding gas supply planning using historical weather data. Liberty feels that it may be preferable to augment planning with a Monte Carlo analysis to capture the proper distribution and cost tradeoffs associated with reserve margins.

  Therefore, all Kentucky LDCs should have clear statements of the weather assumptions used as the basis for gas-supply planning.

- Errors in the short-term weather forecast can impact customer-choice programs and subject LDCs to additional risk due to underdeliveries from third-party suppliers. The most likely resolution would probably be in the form of additional resources in the gas supply portfolio. Such associated costs should then be attributed to choice customers and not firm customers of the utility.

  Therefore, the LDCs should consider conducting analyses to quantify the risk of under-deliveries from third-party suppliers, both in terms of probabilities and costs of historical occurrences, and outline any measures taken to mitigate these risks.

b. Number of Customers

- It is especially important to calculate a demand forecast using separate components, i.e., weather, number of customers and usage per customer, rather than trending historical demand. Such historical trending analysis ignores any changes that may occur in a component that deserves more attention, such as significant changes in the number of firm customers due to a customer-choice program.

  Therefore all Kentucky LDCs should consider incorporating an analysis of the variation in the number of customers as a part of their gas-supply planning.

- Many factors can impact the number of customers and the usage per customer. These factors may impact these two categories of demand forecasting in different ways.

  Therefore all Kentucky LDCs should consider analyzing the number of customers separately from usage per customer, as two separate components in constructing their demand forecast.

c. Usage Per Customer

- Variation in usage per customer is generally the component of forecasting that has the lowest impact on the forecast when compared to other components of the demand forecast. However, it can be significant for certain rate classes with a low number of customers or high usage per customer, or when usage is not weather-sensitive (such as for industrial and some commercial rate classes). Usage per customer also serves as a comparison between utilities and an effective way to evaluate changes due to demographics, conservation measures, or attrition of selective customers for utilities with customer-choice programs (to measure the "cherry picking" effect.)

  Therefore all Kentucky LDCs should consider making a thorough analysis of usage per customer data for each rate class a part of all forecasting related to gas-supply planning.

d. Forecasting Error

- Any demand forecast should incorporate some measure of forecasting error.

  Therefore all Kentucky LDCs should consider making quantification of their forecasting error a part of all forecasting related to gas-supply planning, and for inclusion in rate cases and asset management RFPs.

- Forecasting error due to weather can be treated separately from forecasting error unrelated to weather, such as variations in the number of customers and changes in weather-normalized usage per customer. This approach is an alternative to using a 5 percent or 10 percent reserve margin on top of a forecast that assumes design-day weather. Use of a reserve margin reflects the inability to predict demand, and consequently the potential upside in demand variation that could result from variation in each of the demand components. The goal should be to identify all sources of variation separately. Any variation due to forecast error in the usage per customer of large customers should be attributed to customers in those classes. This practice facilitates attributing the costs of additional resources required to meet that variation to the appropriate rate classes.

  Therefore all Kentucky LDCs should consider analyzing these components separately as part of all forecasting for gas-supply planning.

e. Supply Capacity Planning

Given a demand forecast, potential variation due to weather and the list of resources (i.e. suppliers, pipelines, storage and peaking), it is possible to run an optimization model to evaluate resource usage with respect to various forecast scenarios. Since the main variation component is weather, such forecast scenarios are usually done for a limited number of weather scenarios.

The use of an optimization model allows evaluation of the match between a given resource portfolio and demand scenarios, and identification of excess resource availability. While most utilities choose to evaluate only distinct combinations of scenarios (e.g., demand implied by a cold weather scenario combined with a high customer-increase scenario), it is possible to extend the Monte Carlo analysis into the optimization domain. This analysis can be accomplished by evaluating a multitude of demand scenarios and have the optimization model consider the economic trade-off between meeting incremental demand and the cost of unmet demand, given the probability of each scenario.

- It is possible to evaluate the match between a company's resource portfolio and its demand forecast using a gas-supply optimization model. Since capacity has a cost, utilities should work to minimize costs for customers by evaluating their respective resource portfolios to match potential demand.

  Therefore all Kentucky LDCs should consider utilizing gas-supply optimization models to evaluate their portfolios vis-à-vis demand forecast scenarios.

- Resources that are in excess of high demand forecast scenarios should be considered for revision, retirement or sale. For a proper evaluation, an optimization model should be used incorporating possible demand scenarios. While most utilities have long-term firm contracts that can't be changed in the short run, long-term portfolio planning is essential.

  Therefore, all Kentucky LDCs should be proactive in evaluating necessary or desirable changes in their respective portfolios in advance of expected expirations of contracts.

- The acquisition of additional gas-supply resources, including developing company-owned storage resources, can be evaluated using an optimization model to calculate the value of these additions as a function of the resources that they displace in meeting demand.

  Therefore all Kentucky LDCs should consider utilization of optimization models to evaluate any acquisitions where the increased use of the new resource is shown to cause a decrease in the usage of an existing resource, given proper cost and availability figures for both the new and existing resources.

F. Impacts of Affiliate Relationships on Kentucky Gas Market

The purpose of this area of the audit – Affiliate Relations – was to study whether the dealings of the utility with its affiliated entities in any way limited the distribution company's efforts to lower its costs and the impact those relationships might have on the ratepayer.

Since the mid-1980's, utilities have been acquired into holding companies in order to produce cost savings and economies of scale, and other structural changes have been introduced in order to separate nonregulated activities – and their potential for rates of return in excess of those authorized by regulatory commissions – from the regulated entities. The result has been complex organizations with multiple affiliated companies. The Commission's role has included ensuring fair competition between affiliates and third-party competitors for utility business, and preventing cross-subsidization of costs by ratepayers of nonregulated entities.

The Commission has evidenced interest in the area of affiliated relationships for several years. In September 1998, under Administrative Case 369, the Commission began considering adopting guidelines addressing accounting requirements for cost allocations and affiliate transactions. The Order also investigated issuing a code of conduct for utilities that engage in any nonregulated activities or conduct any business with a nonregulated division, subsidiary or affiliate. Many of the concepts and requirements from the Commission's work were codified into law in House Bill 2000-897 as part of KRS 278, and signed by the Governor in April 2000.

In addition to an evaluation of corporate structures, Liberty's review of the five gas utilities affiliate relationships and transactions centered on several specific questions:

- Do affiliate transactions and dealings meet the requirements of KRS 278?
- Are all dealings with affiliates at arms' length?
- How are costs for joint or shared functions allocated?
- Are affiliate transactions recorded in the accounting system?
- In conjunction with other task areas, are utility gas supply assets knowingly or unknowingly being used to the benefit of affiliates?
- Are there other affiliate issues evident that fall outside the scope of this gas supply audit?

The purpose of listing the above questions that were the focus of Liberty's audit of the five LDCs is to provide background for Liberty's review. It is not the purpose of this chapter to discuss specific findings for each LDC with respect to these questions. Such specific discussion will be found in Section III of this report. Liberty can say, however, that in reviewing LDC activities with respect to each of these questions, no significant issues were found to cause concern that affiliate activities within any of the five LDCs are being conducted improperly.

Given the current corporate structure of most utility companies, possible impacts related to affiliate transactions go well beyond the gas supply function, and therefore beyond the scope of this audit. Affiliate relationships affect such issues as allocation of shared administrative charges and capital costs, lease arrangements, tax sharing allocations and intercompany settlements.

While these areas were not examined by Liberty, Liberty found no indications of need for concern in any of these areas.

1. Affiliate Transactions Addressed in KRS 278

HB 2000-897 amended KRS 278 to address utilities and affiliates of utilities. The summary introduction of the bill indicated its purpose "to prohibit regulated utilities from using revenues to fund unregulated affiliates or from including expenses of unregulated affiliates in the rate base; to require separate recordkeeping; to require the Public Service Commission to establish uniform procedures for cost allocation between the regulated utility and unregulated affiliates by December 31, 2000, and to require utilities to prepare cost allocation manuals in conformance with these procedures; and to create a code of conduct for utilities with nonregulated activities or affiliates." Relevant sections of the bill and KRS 278 are summarized below.

Section 1 of the bill amended KRS 278.010 to add several definitions, including affiliate, control, CAM (cost allocation manual), arm's length, subsidize, and solicit. These terms are all used in subsequent sections of the bill, and ultimately in the statute. In reviewing relationships with affiliates, Liberty has been especially mindful of the definition of arm's length: "the standard of conduct under which unrelated parties, each party acting in its own best interest, would negotiate and carry out a particular transaction."

KRS 278.220 addresses the uniform system of accounts (USoA) for utilities, specifying that the system established for gas companies shall conform as nearly as practicable to the system adopted or approved by the Federal Energy Regulatory Commission (FERC). Liberty's comments on the USoA relative to affiliate transactions are noted elsewhere in this chapter.

Section 2 of the bill added a new section to the statute (as KRS 278.2201) prohibiting a utility from subsidizing a nonregulated activity provided by an affiliate or the utility itself. The Commission is directed to require all utilities providing nonregulated activities, either directly or through an affiliate, to keep separate accounts and allocate costs in accordance with procedures (and related administrative regulations) established by the Commission.

Section 3 of the bill (KRS 278.2203) requires that costs of nonregulated activities within a utility be identified and reported in accordance with the UsoA and either a fully distributed cost method or a method approved by the United States Securities and Exchange Commission (SEC) or the FERC. Valid service agreements (defining the allocation of costs between a utility and an affiliate) need not be changed during the term of those agreements.

Section 4 of the bill (KRS 278.2205) establishes a cost allocation manual (CAM) for utilities, which must contain a) a list of regulated and nonregulated divisions within the utility, b) a list of all regulated and nonregulated affiliates of the utility to which the utility provides services or products and where the affiliates provide nonregulated activities, c) a list of services and products provided by the utility, their definition as regulated or nonregulated, and the cost allocation method applicable, d) incidental nonregulated activities that are identified in the prior section, e) a description of the nature of transactions between the utility and the affiliate, and f) definitions of each USoA account and subaccount as to whether the costs are regulated, nonregulated, or joint, and the allocation methodology used. The CAM is intended to be a public document, and it is to be submitted in any application for an adjustment of rates. The issues surrounding the CAM are addressed elsewhere in this chapter.

Section 5 of the bill (KRS 278.2207) requires that transactions between a utility and an affiliate follow what is known as asymmetric pricing – the price from the utility to the affiliate is either at a tariff rate or at the *higher* of fully distributed cost or market, and the price from the affiliate to the utility is to be at the *lower* of fully distributed cost or market. Allocations in compliance with the utility's existing SEC or FERC approved methodologies are considered in compliance. Allocated costs from shared services units of a holding company, for example, would be exempt from the provisions if service agreements defining those allocations and approved by the SEC are in effect. A utility may file for a waiver from this provision if it can prove that the requested pricing is reasonable, and the Commission may grant the waiver if it is in the public interest. It should be noted that tariff rates are not listed in the pricing structure from an affiliate to the utility. Liberty has found that gas transportation from an affiliate pipeline to a utility is, in all cases, done at FERC tariff rates. Although tariff pricing is not defined in the statute for transactions from an affiliate to the utility, it is not unreasonable to assume that the Commission would find such pricing in the public interest.

Asymmetric pricing provisions are intended to protect the ratepayer from subsidizing affiliate or nonregulated activities, but pricing justification under asymmetric pricing provisions can be lengthy and complex, and difficult to enforce. The fact that the requirement is in statute, however, provides the ratepayer with a significant degree of protection from unfair pricing practices between the utility and its affiliates.

Sections 6 & 7 of the bill (KRS 278.2209 and 278.2211) requires documentation from the utility in a formal Commission proceeding for its cost allocation procedures and affiliate transaction pricing, and provides the Commission access to the books and records – even a full financial audit - of a nonregulated affiliate.

Section 8 of the bill (KRS 278.2213) parallels the language of the code of conduct developed by the Commission under Administrative Case 369. The provisions of the section relate to the sharing of information, databases and resources between utility employees and affiliates in order to prevent unfair competitive practices.

Finally, Section 9 of the bill exempts telecommunications and water and sewer services, and Section 10 provides an opportunity for a utility to apply for a waiver from all provision of the act if the Commission finds that the utility has shown compliance with the act is impracticable or unreasonable.

Liberty has taken the provisions of the statute into account in its review of the 5 utilities under this audit. Specific company by company findings with respect LDC compliance with the statute are contained in Section III of this report.

2. Structure of Affiliated Companies

KRS 278.010(18) defines an affiliate as “a person [includes partnerships and corporations] that controls or that is controlled by, or is under common control with, a utility,” while control (subparagraph 19) “means the power to direct the management or policies of a person through ownership, by contract, or otherwise.” The FERC Uniform System of Accounts (USoA) defines associated (affiliated) companies as “companies or persons that directly or indirectly, through one or more intermediaries, control, or are controlled by, or are under common control with the accounting company.” The USoA continues: “"Control" (including the terms "controlling," "controlled by," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, associated companies, contract or any other direct or indirect means.”

Each of the five utilities examined under this audit is an affiliate of entities not regulated by the Commission. Three of the five have significant administrative functions provided by affiliated service companies; a fourth has a shared services division; the fifth provides all services to subsidiaries. Three utilities are subsidiaries of a company registered under the Public Utility Holding Company Act of 1935. Several have gas marketing affiliates; two have gas producing/gathering affiliates active in Kentucky.

Columbia Gas of Kentucky (Columbia), Louisville Gas and Electric Company (LG&E), and Union Light, Heat and Power Company (ULH&P) are each wholly-owned subsidiaries of companies registered under the Public Utility Holding Company Act of 1935 (PUHCA). This corporate structure has several implications.

a. Shared Services

The economic rationale behind a holding company is that common services can be provided to all subsidiaries at a lower total cost than each subsidiary could provide it for itself. Under PUHCA, this leads to the creation of service companies, whose full costs of operation are then allocated to the other affiliated companies. (Columbia, LG&E and ULH&P each have affiliated service companies that provide administrative services – legal, human resources, accounting, etc.) In other words, the service company should have zero net income – neither profit nor loss for its operations. The need to allocate costs among regulated and nonregulated affiliates begs the question of the appropriateness of the allocations, because ultimately the ratepayers are charged those costs that go to the utilities.

Also required under PUHCA, all intercompany transactions must be approved by the SEC, and holding companies must file service agreements formalizing the activities between affiliate companies.

Western Kentucky Gas Company (WKG) is a division of Atmos Energy doing business as WKG in Kentucky. All of its other utility operating companies (Greeley Gas, Energas, etc.) are also divisions of Atmos, rather than separate affiliated companies. Atmos has a services division that provides similar administrative functions as a separate services company. Again, it is important for the Commission to be able to study how costs are allocated to the Kentucky utility.

Delta Natural Gas Company (Delta) is the parent of three unregulated affiliates that have no employees, and the utility provides all services to the subsidiaries, allocating the employee time spent on affiliate activities. Delta is the only company in the audit that is not associated with one or more utility companies within its corporate structure.

b. Gas Procurement within the Corporate Structure

In the chapter on affiliate relations for each individual utility, Liberty has noted the gas procurement model used by the LDC. There are two broad categories, one where a service company provides gas procurement, and the other where gas procurement is done within the utility itself.

In-house gas procurement is straightforward with regard to affiliate transactions. Costs of the department(s) do not have to be allocated among utilities, and all supply contracts – commodity and pipeline – are dedicated and expensed to the specific LDC. The Commission may evaluate whether the level of costs is appropriate, but it does not need to look at how those costs are split among multiple regulated and nonregulated affiliates.

LG&E uses an in-house procurement group for gas supply, even though there is a service company that provides other administrative and joint services. Delta also procures its own gas supply through an in-house model; the same employees, however, also procure gas for affiliated companies and for transport customers, leading to issues of time and cost allocation among the companies.

Gas procurement for two or more utilities by a services organization brings several benefits. The ability to aggregate requirements can provide the group with a potentially stronger negotiating position, leading to possible price advantages to the utility customer. Typically, these groups also have fewer employees than would be needed were each utility to have its own supply department. From an affiliate transactions standpoint, however, the model raises issues of how costs of employees, overhead, capital expenditures for computer hardware and software, etc., are allocated among the utilities.

Columbia, ULH&P and WKG use the service group procurement model.

Within those two broad alternatives, in-house procurement and services group procurement, there is a third significant procurement model – the asset management contract.

An asset management contract means that a third party is responsible for the provision of gas to the city gate to meet the daily requirements determined by the utility. Under these agreements, either the utility's commodity and capacity contracts are assigned to the asset manager, or the asset manager simply provides the requirements under its own existing contracts. Typically, the agreements are for full requirements – the utility agrees to allow the asset manager to provide 100% of the demand – and the utility does not procure any additional supply. The asset manager is then able to use any excess capacity, storage and supply to its own benefit as long as the utility's load is met.

In general, Liberty has found that asset management agreements provide benefit to the utility customer - in the form of either a discount off of index for the commodity costs or through payments back to the utility – in exchange for the right to use the supply assets. Further, some utilities have been able to scale back their gas supply staff significantly, because the nominating, balancing, off-system sales and capacity release functions take place with the asset manager, not within the utility.

With regard to affiliate relationships, however, the asset management model effectively raises a barrier between the underlying transactions and the Commission. Because the asset manager typically invoices the utility under its name for all commodity, transportation and storage transactions on a single invoice, there is no way to analyze individual transactions that might be made with a utility's affiliate. Liberty emphasizes that there was no evidence that utilities were in any way attempting to conceal inappropriate transactions with affiliates under an asset management agreement. Liberty simply points out that the nature of the agreements is such that activities where affiliates are unfairly favored could occur, and auditing such transactions could be very difficult.

Delta (for the northern part of its system), ULH&P and WKG use asset management agreements.

In summary, the following gas procurement models are used by the five LDCs:

- Columbia – Service group procurement
- Delta – In-house procurement, asset management contracts
- LG&E – In-house procurement
- ULH&P – Service group procurement, asset management contract
- WKG – Service group procurement, asset management contract

Any affiliate relations issues related to the procurement model are addressed in Section III of the report in the chapter specific to each utility. Liberty does note, however, that no one procurement model is inherently superior to another. The above discussion is intended to provide background on the range of procurement models used within the five LDCs in order to provide better understanding of how each LDC uses its own model. This will be helpful when the detailed discussion in Section III for each LDC is considered.

c. Other Affiliates

All of the utilities are affiliated with entities not regulated by the Commission. In addition to the service organizations already noted, the affiliated companies include utilities regulated by other states, interstate pipelines regulated by FERC, and other nonregulated affiliates.

3. Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

Overall, Liberty has found that gas supply transactions between the utilities and their affiliated companies are generally at either tariff or market rates. This is what Liberty would have expected to find.

Most of the utilities do little or no business with their gas marketing affiliates. Delta eliminated all gas purchase transactions with its affiliate because of the difficulties they foresaw in meeting the asymmetric pricing directive of the Kentucky statute. LG&E discontinued the operations of its unregulated natural gas marketing affiliate company, and ULH&P and Columbia affiliates provide a very small percentage, if any, of their supply commodity.

Western Kentucky Gas, the only utility with a substantial relationship with an affiliated gas marketing entity, awarded the affiliate the contract following a competitive bidding process, and after the initial award to another company was found to be unworkable. Western went to the Commission for review and approval (Case 1999-447) of the award process.

Western also has unregulated storage affiliates, but the company does no business with them directly. Woodward Marketing, Western's gas marketing affiliate, does use the storage affiliates in the provision of asset management services to Western and other customers.

The fact that affiliate transactions are at rates identical to those third-parties would be charged does not necessarily mean there are no affiliate issues to be considered, as will be indicated below.

Both ULH&P and Columbia have pipeline affiliates, and each company transports gas over its affiliated pipeline at FERC tariff rates. ULH&P's pipeline affiliate is KO Transmission Company, which has no employees; all services are provided by Cinergy Services, Inc. Columbia has two major pipelines as affiliates – Columbia Gas Transmission Corp. and Columbia Gulf Transmission Co.

Prior to Order 636, ULH&P/CG&E had been a full requirements customer of Columbia Gas Transmission. Recognizing the need for access to additional supply and transportation sources, CG&E acquired the KO Pipeline, which gave them access to additional pipes. Since the acquisition, the company has used KO to connect to Tennessee Gas Pipeline and Columbia Gulf. Access to additional supply pipelines has enabled ULH&P (through the Gas Operations group) to negotiate for better pricing for its gas transportation and to expand the number of potential commodity suppliers. The positive aspects of this situation are discussed in detail in Section III.D of this report.

Columbia delivers virtually all of its supply over its affiliate, Columbia Gas Transmission. Columbia maintains it has very limited options with regard to pipeline and storage capacity, but there seem to have been few analytical studies made to evaluate alternative sources. Regardless of the affiliate status of the sole supplier pipeline, limited delivery options can hinder a buyer's competitive position in the marketplace, both for commodity and transportation/storage. The affiliate relations issue is whether the inability to secure alternative supply sources is due to the economics of the situation, or whether it indicates a bias toward maintaining the status quo relationship with the affiliate pipeline(s), even though the actual transactions occur at tariff rates. This is discussed in detail in Section III.A of this report, including recommendations designed to improve this situation.

(Note: Delta also acquired the Tran-Ex Pipeline in order to enable flows across their system, provide access to alternative supply sources, and to provide adequate transportation capacity to fill the Canada Mountain storage field. Tran-Ex was originally a subsidiary, but was absorbed into the utility. This is discussed in detail in Section III.B of this report.)

Liberty notes for the Commission that the apparently similar relationships between ULH&P and Columbia and each of their respective affiliate pipelines – transporting gas at tariff rates – might in fact have very different results for the ratepayer. Section III of this report provides detailed discussion of the results of each of these actions by these LDCs.

Only LG&E provides gas for the electric side of its company, and only on a very limited basis. Details of the transactions are provided in the affiliate relations chapter for LG&E.

a. Non-Gas Transactions with Affiliated Companies.

Most of the transactions between affiliates that are not related to gas supply are charges by service companies. The companies that provided a Cost Allocation Manual (Delta, LG&E and Western) detail how those administrative costs are allocated.

Other transactions between the utility and affiliates are beyond the scope of this gas supply audit. The Commission is aware of the number of companies with which most of the utilities are in some way affiliated, and has the authority to pursue the details of all affiliate transactions.

4. Accounting and Reporting Issues for Affiliate Transactions

The primary way for the Commission to identify and audit affiliate transactions is through the utilities' accounting systems. The sources of many of the transactions are the allocations from shared services organizations. Auditing affiliate transactions requires, first, an understanding of the allocation methodologies used by the companies for joint costs; second, a review of how employee time and related costs are tracked; and third, how affiliate transactions are entered into the chart of accounts. Each of these is addressed below. Audit of LDC accounting systems was beyond the scope of this project. The areas discussed in this section do relate to gas procurement and therefore the following discussion is presented both to explain this relationship, as well as to provide background information that will be helpful in understanding the complexities related to accounting for affiliate transactions.

a. Cost Allocation Manual (CAM)

Combined gas and electric utilities have always had to allocate joint administrative costs, especially when utilities offered services that had been removed from rate base, such as appliance sales and/or repair. In today's corporate climate, all but the most incidental nonregulated activities have been spun off into separate entities – entities that still must be allocated joint costs.

Registered holding companies' shared administrative organizations allocate 100% of their costs. Atmos' shared services division has the same obligation. Delta, where utility employees provide all services to its subsidiaries, also must identify a way to fairly and accurately spread costs among the affiliated companies. These costs can include departmental expenses for areas such as legal, accounting, human resources, and computer technology. Often, these costs can be directly attributable to a specific entity, and remaining costs are allocated based upon factors that are straightforward - employee counts or number of customers. There are also costs for debt and capital expenditures, among others, that are more difficult to allocate based on easily determined factors such as number of employees or number of customers.

Every regulatory jurisdiction recognizes that there are appropriate costs that should be included in rates. The task for the Commission is to ensure that Kentucky customers pay their full share, without paying for any costs that should be rightly assigned to another regulated or nonregulated entity. The Commission requires information about the cost allocation process with every rate case.

The Commission also developed the outline of a cost allocation manual under Administrative Case 369. As noted earlier, the CAM was to include a list regulated and nonregulated divisions within the utility, and a list of all regulated and nonregulated affiliates of the utility, as well as a listing of each ledger account and subaccount detailing whether the costs are regulated, nonregulated, or joint, and the allocation methodology used.

Creation and distribution of a CAM serves many purposes. First, a CAM allows the Commission to evaluate how costs are allocated not only among regulated and non-regulated activities within a utility, but also between and among affiliated entities and the utility itself. The allocation of costs from shared service organizations deserves thoughtful consideration and a detailed explanation from the utility holding company, as each ratemaking body works to ensure that its customers pay the full costs of their service, without bearing costs that do not belong to those customers. Regulatory agencies across the country recognize the need to understand the cost allocation process as the nature of the utilities they regulate have changed over time from stand-alone utilities to utility holding companies with multiple regulated and unregulated affiliates. If each utility submitted a CAM, they could be evaluated with respect to each other, allowing the Commission to identify best practices, if desired, and to study the alternative approaches to allocating similar types of costs.

Secondly, a CAM serves as an internal employee training tool, as well as providing information to the public and ratepayers:

- Corporate structure is often defined in a CAM, because the structure forms the basis for the need to allocate costs. New employees, and many current employees, can be confused by the number of entities within a holding company, and they are often unsure of their relationship with affiliated companies.
- Defining and explaining in a CAM the types of services provided by various departments helps employees understand the function not only of the company entities, but of the functional departments with those companies.
- Management employees in particular benefit from the allocation methodologies defined in a CAM, which detail how costs are apportioned from or to their departments. Most utilities have found they need to define a variety of allocation factors depending upon the types of costs being allocated, when such costs cannot be charged directly to an affiliate or department. These factors can include, for example, number of employees, number of customer meters, utility plant in service, etc.
- A CAM usually defines when allocation factors are reviewed and/or recalculated, to ensure their ongoing accuracy.
- How employees are to record their time is a typical CAM topic. (Time reporting is discussed in more detail in the following section of this chapter.) An accurate method of recording time serves as a foundation for cost allocation, and employees need to understand distinctions between positive time recording and exception time reporting. Exception time reporting requires an understanding of how time is typically allocated, so an exception can be identified.
- A CAM, as it defines corporate structure and function, can also be a logical place for detailing code of conduct issues between affiliates, such as those listed in KRS 278.2213, which addresses activities related to the sharing of information, databases, and resources between utility employees and employees of marketing and/or non-regulated affiliates.

Service Agreements under PUHCA will detail how costs for shared services are to be allocated among affiliates, so that much of the information to be consolidated into a CAM will already be defined for registered holding companies.

Delta, LG&E and Atmos / WKG submitted CAMs that identified the methodology used to allocate costs between the utility and the affiliated companies. Delta's allocation method is fairly basic, and is an identical calculation across all categories of joint costs. LG&E and WKG have very detailed calculations for each of the cost areas that are allocated from the service organization to the utility.

Columbia and ULH&P stated that their companies were exempt from the requirement to submit a CAM because the unregulated activities within the utility did not exceed the threshold limits defined in the statute. While Section III of this report provides additional discussion related to this situation for these two LDCs, it was clear to Liberty that the absence of a CAM for these two LDCs did not imply any inappropriate allocations of costs for them.

The statute (KRS 278.2205) requiring a CAM reads: "Any utility that engages in a nonregulated activity whose revenue exceeds the amount provided for incidental nonregulated activities…shall develop and maintain a CAM…". In a time where affiliate entities are created outside the utility specifically to house nonregulated activities, it is not surprising Columbia and ULH&P have claimed an exemption from the CAM based upon the "incidental nonregulated activity" exclusion.

Liberty agrees that, given the specific wording of the statute, the filing of a CAM is not required for Columbia and ULH&P. However, it appears that the language of the statute does not fully incorporate the intent found in the opening paragraph of the Commission's Second Revised Cost Allocation and Affiliate Transaction Guidelines, which states:

> These guidelines shall apply to any utility that engages in any nonregulated activity *or conducts any business with an affiliate*. The purpose is to ensure that all appropriate costs, including common costs, of providing nonregulated services or products are allocated to the nonregulated activity and are not subsidized by the utility's ratepayers. The guidelines are also *intended to preclude ratepayer subsidization of affiliated entities by ensuring that transactions between a regulated utility and its affiliates are conducted in a fair and consistent manner.* (Emphasis added.)

The summary paragraph to HB 2000-897 includes the following:

> …to require the Public Service Commission to establish uniform procedures for cost allocation between the regulated utility and unregulated affiliates…, and to require utilities to prepare cost allocation manuals in conformance with these procedures…

Both of these references seem to indicate that one objective of the cost allocation manual was to look at transactions between the utility and any unregulated affiliates.

It is clear that the Commission recognized the need to look at the allocation of costs between the utility and the unregulated affiliates in order to prevent any ratepayer subsidization. Liberty suggests that the Commission consider ways to return the original intent of its requirements either to the statute or to any procedures and administrative regulations it might develop, so that the Commission can review all of the companies' allocation methodologies.

b. Allocation of Employee Time and Overheads

When an employee provides services for more than one cost center, whether the cost center is another company department or an affiliate, there are issues surrounding how time is charged to the appropriate entity. Because the standard is fully distributed cost (also known as fully burdened cost), employee overheads, including company contributions toward benefit costs (health, worker's compensation, etc.), vacation and others need to be included in the calculation. Generally, however, the determining basis for any cost allocation is recorded time spent on work for another cost center.

Recording time is one of the foundations of cost allocation. All employees should understand the importance of accurately recording time and how their time is charged and allocated to other companies and departments. Management and supervisory employees should understand their own and their department's allocation basis for employee time, capital costs and all other shared costs, providing training to their employees as needed. Management and supervisory personnel should make a concerted effort to ensure their own and their employees' time records are maintained daily, rather than completed at the end of the payroll period.

There are three basic methods of recording time, and each one may be appropriate for allocating employee time and overheads among affiliates – positive time recording, exception time reporting, and pre-determined allocation of time.

Positive time recording is best used when employees have discrete tasks that can be charged to a specific cost center. When this format is used, all chargeable time is tracked in agreed upon increments – 1/10 hour, ¼ hour or ½ hour increments, for example. Employees have charge codes to ensure that time goes to the appropriate cost center. Accounting tasks performed by a services unit, which are usually performed for the benefit of a specific entity, can be an example of functions where positive time recording is the best selection.

Exception time reporting means the employee performs tasks primarily for his/her home department. Thus, all time is charged to the employee's cost center unless tasks are undertaken which should be charged to another entity. A manager of an in-house gas supply department who works on a special project for another cost center might use exception time reporting – only those hours spent on the project are recorded and submitted.

Allocation time reporting is most appropriate for functions which apply equally and without differentiation to all cost centers – benefits administration, for example – so that total employee time-related costs are allocated based upon an allocation equation. For benefits administration, that equation might include total numbers of employees, total payroll, or total benefit costs for each cost center. Gas load control employee costs, when it is done for more than one utility, might be allocated based upon volumes delivered to city gates, or total meters.

Liberty has found that most of the utilities use some combination of time reporting methods. When the gas supply unit is part of a shared services organization, most utility gas supply groups direct charge time (and other expenses) to a specific LDC whenever possible and remaining time is generally allocated. Positive time recording is most often used by shared services groups such as accounting. When the function is entirely within the LDC, exception time reporting is the rule.

As corporate organizations become more complex, combining regulated and nonregulated entities, it is very important that employees at all levels understand the time allocation philosophy of their work area. Particularly in a shared services environment, employee understanding of both 1) the reasons behind the need for fair and accurate allocation of shared costs and 2) the process of that allocation becomes very important. While the process of time allocation directly affects what costs are properly borne by ratepayers, Liberty did not find any indication that improper time allocations by the five LDCs were adversely impacting ratepayers.

c. FERC Uniform System of Accounts

Kentucky statutes state that the system of accounts for gas and electric companies shall conform as nearly as practicable to the system adopted or approved by the Federal Energy Regulatory Commission (FERC). All of the utilities base their charts of accounts on the FERC Uniform System of Accounts (USoA).

The USoA undergoes periodic revisions in order to provide for the changing nature of the utility business. In the version referenced for this audit (current through January 18, 2002), several additions and revisions to the text were noted as being effective pending Office of Management & Budget approval, evidencing its status as an active, changing document. The USoA addresses associated/affiliated transactions as follows:

> 14. Transactions with associated companies. Each utility shall keep its accounts and records *so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies.* The statements may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature. *Nothing herein contained, however, shall be construed as restraining the utility from subdividing accounts for the purpose of recording separately transactions with associated companies*. [Emphasis added.]

Not all of the utilities specifically identify gas supply transactions with affiliates within the chart of accounts. Some stated that the number of affiliates dealt with is limited enough that the accounting system (accounts payable vendors, for example) can simply be queried by the affiliate name. Within the narrow scope of this audit of the gas procurement functions of the five utilities, there are, in fact, a limited number of possible affiliates with which the companies do business. In the broader scope of affiliate transactions within utilities with many affiliates, however, the ability to “accurately and expeditiously” produce statements of all transactions with affiliated companies requires a more structured methodology.

The use of subaccounts for affiliate transactions is a straightforward method of being able to accumulate such transactions within the appropriate accounts. The advantage to the Commission of the use of subaccounts is in being able to identify whether, and to what extent, transactions are being made with affiliated entities. Thus, during an audit or a rate case, the Commission has a place to begin determining whether affiliated transactions could lead to any cross-subsidization with nonregulated entities.

Some regulatory commissions require that all affiliate transactions be reported to the commission. These reports can frequently be voluminous, including, for example, every payroll transaction where time is charged to an affiliated entity. The Commission can decide if such information would be valuable on a routine basis. Liberty does recommend that the Commission consider requiring such affiliate transaction accounts and looking at them during rate case hearings or at other times when the information might be of value.

d. Other Accounting Issues

Overall, Liberty found that invoicing for gas supply (commodity and transportation) is adequately reviewed and verified by the utilities prior to payment authorization, with supporting documentation forwarded to accounting. Where that has not been the case, specific recommendations have been made within the chapters related to the utility.

Intercompany accounts are cleared and duplications eliminated in consolidated public financial statements. The company structure – holding company, divisions, etc. – may determine whether intercompany accounts are cleared through cash instruments or through journal entries to the general ledger. Liberty believes that intercompany accounts should be cleared monthly

III. Company-by-Company Reports

B. Delta Natural Gas Company

1. Gas Supply Planning

a. Scope

This chapter of Liberty's report addresses Delta's gas supply planning. Aspects considered include the following:

- Integration with Corporate Plans
- Load Forecasting/Risk Analysis
- Balancing Supply Options
- Supply Planning Flexibility
- Impact of New Markets
- Monitoring of Key Assumptions and Plan Implementation
- Peak Period Performance.

b. Background

(1) Integration with Corporate Plans

Delta has an effective strategic planning process that is described in Chapter 2, Organization, Staffing and Controls. The organization responsible for natural gas procurement and management, the Gas Supply Department (*Gas Supply*) has stated objectives that are developed as part of each year's Strategic Plan, but does not have written quantitative goals.

The gas-supply planning and decision process is an informal one, as Delta is a small company, and very few people are involved in addressing gas-supply issues. Most analysis is done by the Director, Gas Supply Transportation, and provided to the Manager, Gas Supply. Those two individuals seek the advice and counsel of their supervisor, the Vice President - Operations & Engineering, and the Company President as necessary. Company officers provide guidance and oversight, but the two managers negotiate all contracts. Company policy regarding authority levels requires that the Vice President – Operations & Engineering (or the President) sign all gas-supply contracts, but those individuals do so on the advice of the two managers.

Delta uses full-requirements contracts for the northern parts of its service territory, under which suppliers operate Delta's contracts for pipeline and storage capacity to provide supply to the Company's city-gate receipt points. The requirement that involves the majority of corporate planning is for the Company's Southern System, which is supplied from a Company-owned storage field. Supply must be bought and injected over the course of the non-heating season, so that the facility is full at the beginning of the heating season.

(2) Load Forecasting/Risk Analysis

Delta's load forecasting process is as follows. Sendout in July and August is divided by the number of days and the number of customers to get base-load use factors. Delta then subtracts base load from total load to get heating load, and regresses heating load against weather and number of customers to get heating use factors. These calculations are by customer class, including one residential class and two commercial classes. Base- and heating load factors are multiplied by the number of customers and a design criterion, expressed in terms of heating degree-days (HDD), to get peak-day requirements.

An annual forecast is prepared as the Annual Supply Plan. The Annual Supply Plan is based on normal weather. The plan is updated through the course of the year.

Under Delta's full-requirements contracts, the suppliers commit to providing 100 percent of Delta's requirements, to the agreed delivery points, whatever those requirements might be. There is a limit on the maximum daily quantities that the suppliers agree to provide, and those limits are equal to the maximum daily quantities in the respective pipeline transportation contracts that the suppliers administer. For quantity nomination purposes, Delta is required only to estimate daily average quantities for each month, and to provide those estimates to the full-requirements suppliers serving the Company's northern service areas. Delta's Southern System requires more careful tracking of quantities injected into the storage field and withdrawn, as the quantity remaining in the field at any point during the winter must last through the winter, and peak deliverability must be maintained through the peak day that normally occurs around the first week of February.

Gas Control prepares short-term forecasts that cover operations over the next few days. The purpose of these forecasts is to make sure that the various sources of supply have enough deliverability available to Delta to keep the Company's customers supplied.

Little risk analysis is deemed necessary. The full-requirements suppliers are substantial firms, so Delta expects that they will continue to perform satisfactorily. For the Southern System, the principal risk is that the facility would not be sufficiently full on an early-February peak day, so Delta watches closely the storage level throughout the winter.

(3) Balancing Supply Options

Delta's supply-planning process contains the desired elements for evaluation of demand, that is the number of customers, use per customer, and growth rates for each demand area. Delta considers its supply options to be constrained because many areas are served by only one interstate pipeline.

For its northern areas, Delta's systems are mostly unconnected links to the Columbia Gas Transmission and Tennessee Gas Pipeline systems. Delta has had the same capacity contracts on Columbia Gas Transmission (and Columbia Gulf Transmission) since implementation of the

FERC's Order 636 in 1993. Delta's Tennessee contracts have been increased to accommodate market growth.

The Southern System is integrated, but it is somewhat isolated from Delta's northern system and thus from the gas supply resources available on several interstate pipelines in central Kentucky. Delta's Tran-Ex pipeline is connected to Columbia Gulf, but the Company has no firm capacity rights on that system. Delta has 1,800 Mcf/day of capacity on Columbia Gulf that, coupled with the 5,400 Dth daily entitlement under the Delta-Cumberland GTS contract with Columbia Gas Transmission referenced in Chapter III.B.6.b.(1), is dedicated to the exclusive supply of gas to its Beattyville service area, which is served from Columbia Gas Transmission's KA-1 line, and the southern systems served from Columbia Gas Transmission's Greenbriar delivery point. Thus, Delta's analysis of its supply options for the Southern System have largely been limited to possibilities involving the Company's new storage field.

As noted above, Delta uses full-requirements contracts for supply of its northern service areas. One of those contracts was redone in 2000, but the other has been in place since 1993. For the Southern System, Delta mostly buys spot-market supplies during the summer, has the gas delivered to Columbia Gulf's Speedwell Purchase Station, and then moves it down the Company's Tran-Ex pipeline to the Canada Mountain Storage Field. Delta has been using the same supplier for most of those volumes since development of the storage field began in 1995.

Delta's service agreements with Columbia expire in 2008. Delta believes that due to the distance between Delta's service areas and other interstate pipelines, there are no other feasible alternatives for the supply of these areas. Some study has been done of the possibility for using some of Delta's storage capacity to replace capacity under contract on the Tennessee system.

(4) Supply Planning Flexibility

Delta believes that it has little flexibility in its supply planning. Its northern service areas have nine city-gate delivery points on Columbia Gas Transmission, each with its own level of contracted delivery capacity, and none connected with another. The situation is similar for its seven delivery points on Tennessee. To date, Tennessee has allowed Delta to use its capacity across its delivery points without regard to contract quantities attached to individual points, as long as deliveries are taken in the same rate zone. Delta notes that the delivery-point-specific quantities are in its service agreements with the pipelines, however, so the Company does not feel free to disregard them in its supply planning.

Flexibility for the Southern System is also limited, but for reasons of isolation. Delta feels that the only way to get enough gas to its Southern System is to use Tran-Ex to fill the Canada Mountain Storage Field in the summer. As noted earlier, Columbia Transmission's KA-1 pipeline is physically connected to the Southern System, but Delta has insufficient firm capacity rights to make this a viable supply alternative in the winter. Delta's Canada Mountain Storage Field has sufficient deliverability and capacity to supply the Southern Systems' peak day requirements. TCO's KA-1 pipeline does not have sufficient capacity nor adequate supply pressure required by Delta's system to supply Delta's winter requirements.

Delta has not offered small-volume transportation service in its service areas below 25 Mcf per day. Delta acknowledges the possibility that it might have to further unbundle its supply services some day, and in recognition of this possibility has included a regulatory-out provision in its full-service supply contracts.

As noted earlier, Gas Control prepares short-term forecasts, for the next few days, that are focused on making sure that contracted supplies and pipeline capacities are sufficient to supply the needs of Delta's firm customers. Delta's Director, Gas Supply Transportation does nominations and scheduling for Delta Resources's customers, and communicates that information, and similar information for Delta's transporters other than Delta Resources, to Delta Natural's suppliers (Dynegy and Woodward). Information on Delta's sales-service load is required only monthly. Thus, there is no real need to connect Gas Control's short-term forecasts with monthly or annual requirements estimates.

(5) Impact of New Markets

Delta has no specific analysis of the impact of new markets; rather, a simple growth rate is applied for each customer class and market area. Delta's current assumptions are three percent annual growth for residential customers, and one percent growth for commercial customers. These assumptions are in line with the observed growth rate of approximately 2.5 percent for 2000. Delta's Marketing personnel provide growth estimates by supply area so that Gas Supply can analyze the adequacy of its supplier and pipeline contracted capacities.

(6) Monitoring of Key Assumptions and Plan Implementation

Delta tracks sendout on a peak-day and monthly basis, and compares those figures to revised requirements figures to assess the amount of forecasting error. The difference is usually in the one–to-three percent range for peak-day requirements. The numbers were 2.4 percent for 2000, and 2.7 percent for 2001, and no more than 10 percent on a winter-month basis.

Delta feels that this is sufficient because curtailment is not a problem on the pipelines, and Delta's operational balancing agreements provide more than enough tolerance for any short-run imbalance to be corrected. Capacity is not a problem on Tennessee, and Delta is on a one-part rate schedule for its Columbia capacity, so the Company is billed only for what it uses. The updated use factors are used in the succeeding year's forecasts, however, to reflect trends in consumer usages such as the effects of conservation.

(7) Peak Period Performance

Delta uses a design criterion of 80 heating degree-days (HDD) for its northern service areas, and 77 HDD for its Southern System. The coldest day experienced recently was 76 HDD, in January 1994.

Since its peak day design criterion is relatively conservative, Delta has experienced no delivery problems. Delta's contracts on Columbia and Tennessee provide sufficient peak-day capacity in the north, and the design parameters for the facilities upgrades and additions, which are necessary to maximize the delivery of gas withdrawn from on-system storage and deliver it to the market areas in the southern system, provide sufficient capacity there as well.

c. Conclusions

(1) Delta's peak-day requirements estimation is conservative. (*Recommendation #1*)

In estimating its peak-day gas requirements, and thus its requirements for peak-day delivery capacity, Delta uses design weather of 80 heating degree-days (HDD) for its northern systems, and 77 HDD for its Southern System, derived from actual minimum temperatures observed. Delta reports that the Company experienced 76 HDD on January 21, 1994, which was one of the coldest days (January 19-21, 1994) in Kentucky.

Delta reports that it collects weather information from the weather stations at the Lexington airport, Berea College, Farmers, Barbourville, London, Manchester and Williamsburg, Kentucky. However, only the station at the Lexington airport is used for peak day planning purposes. According to weather data available from the National Climactic Data Center of the National Oceanic and Atmospheric Administration, the Lexington airport has had only two days with weather as cold as 74 HDD (daily average) in the last 54 years, and no days colder than that. None of the weather stations used by the five LDCs that are the subjects of this audit has had a day colder than 77 HDD in the last 54 years.

Delta's use of 80 and 77 HDD for estimating its peak-day capacity requirements is conservative. Use of a less conservative design criterion might free up some capacity, but at the potential risk of inadequate peak day supply on an extremely colder than normal day.

(2) New storage and transmission facilities may be able to do more than provide secure supplies for Delta's Southern System customers. *(Recommendations #2 & #3)*

As discussed in more detail in Chapter 3, Gas Supply Management, Delta has been engaged for a number of years in a program of facility replacements to enhance system integrity and eliminate capacity constraints in its Southern System. The Canada Mountain Storage Field was added to replace that system's previous reliance on local supply. The Company has under construction a high-pressure link between the storage field and Delta's southern-most connection to Columbia Gas Transmission's facilities at the Greenbriar Purchase Station.

While those facility additions were for the purpose of assuring reliable service to Delta's customers, they may be able to do more. Liberty feels that the following should be considered:

- Delta's preliminary estimate for the working-gas capacity of the Canada Mountain Field was 4.4 Bcf, based upon the volumes produced from the field prior to Delta acquiring the field and converting it to storage. The November-to-March requirements of Delta's Southern System customers are 1.9 to 2.0 Bcf. As the field further develops Delta could perhaps have storage available for other purposes.

- Delta has designed the facilities that bring gas to the field and take gas away from it for uniform, season-long injection and withdrawal rates, amounting to injection of 20,000 Mcf/day for 200 days, and withdrawal of 40,000 Mcf/day for 100 days. If gas could be re-injected after some is withdrawn, Delta would possibly be able to sustain the maximum withdrawal capability more days than are currently planned.

- The storage field on its own has a calculated capacity to deliver 80,000 Mcf/day at the start of the withdrawal period when it is at maximum pressure. However, as mentioned above, pipeline, measurement and gas treatment facilities are designed for a maximum withdrawal of 40,000 Mcf/day. Significant facility modifications and upgrades would be required before the use or sale of peak-day storage capacity or peak-shaving capabilities would be possible at levels above the designed 40,000 Mcf/day.

- Delta's actual peak-day requirement on its Southern System is currently 37,400 Mcf/day. As is apparent in the comparison of that number to the planned rate of 40,000 Mcf/day, that requirement consumes almost all of the design withdrawal capability at the storage field. Use of a less-conservative peak-day weather design criterion, along with other modifications as discussed in Conclusion #1 above, could result in more of the system's withdrawal capability being available for other markets.

- Delta has additional sources of gas supply that either are available or could be available to its Southern System on the peak day. Delta maintains a contract for delivery of 5,400 Mcf/day from Columbia Gas Transmission, for example. A portion of this capacity is used to provide service to Delta's customers in Beattyville. The Manager – Gas Supply reports that Columbia Gas Transmission does not permit GTS contract entitlements (capacity) to be assigned to alternate points of delivery. Moreover, Delta's Tran-Ex pipeline is capable of delivering 20,000 Mcf/day into the Southern System. Delta does not now have a firm supply of gas that could be delivered to Tran-Ex (for re-delivery to Delta), but such a supply could be arranged, especially through an exchange. However, the reservation fees to reserve firm capacity on Columbia Gulf for delivery to the Tran-Ex interconnect to insure peak day deliveries could eliminate this as an economically feasible alternative peak day supply source. Local Kentucky supplies are also delivered into Delta's Southern System. While those supplies are generally delivered into Columbia Transmission's KA-1, arrangements could be made whereby they would be used to provide service to Delta's customers.

Additional possibilities may exist through displacement or exchanges among any or all of the enumerated sources.

While Delta is aware of these possibilities, plans to consider them further await facilities additions and the conclusion of the development of the Canada Mountain storage field.

d. Recommendations

(1) Delta should consider less conservative design criteria for its peak-day requirements estimation. (*Conclusion #1*)

Delta should consider design criteria that are based on a less conservative standard, such as a three percent probability of occurrence. A three percent probability of occurrence would yield a design peak day of 74 HDD for Delta's northern systems, and perhaps as low as 68 HDD for its southern System. The 68 HDD is the three percent probability weather for Paducah, Kentucky, which is one of the weather observation stations used by Western Kentucky Gas, and is at about the same latitude as Delta's southern System. This change could reduce the Company's requirement for peak-day supply capacity.

(2) Delta should further evaluate its facilities as more capacity is added and report to the Commission on its facilities as they are developed and analyzed. (*Conclusion #2*)

Delta has in concept a program for analyzing the capabilities of its facilities as they are developed. Liberty recommends that Delta formalize that program, and report on it to the Commission.

Delta's analysis should focus on the storage field and its new transmission facilities in serving Delta's customers on its Southern System that include the following:

- The working-gas capacity of Canada Mountain when the field is fully developed.
- Whether injection and withdrawal can be conducted other than uniformly to exploit the maximum deliverability that could exceed design deliverability of 40,000 Mcf/day.
- The potential for moving gas across Delta's system (from north to south, and from south to north) under near-peak and peak load conditions, considering operational parameters on connecting pipelines.
- What questions can be evaluated by computer simulation, and what questions require field measurements.

After submission of the initial report, Delta and the Commission Staff should meet to review Delta's analysis and plans.

(3) Delta needs a more formalized plan for utilizing the capabilities of its systems, as they develop. *(Conclusion #2)*

Liberty's analysis suggests that facilities that are currently in place or are being completed could deliver more services, and perhaps different services, than are being provided now. Liberty's supply modeling suggests that, with Test Case weather, and if Delta chooses to develop the full potential of Canada Mountain, Delta's facilities could handle 20 percent more demand than they are currently serving, for example.

Liberty concedes that our analysis presumes facility capacities as they have been presented to the Commission in certificate proceedings, and that those capacities are not yet proven. When actual capacities have been proven, however, Delta should prepare an analysis of its systems' capabilities, and should develop a plan for realizing their potential.

It should be noted that Delta has lost three large end-users of gas from its Southern Systems due to plant closings. Delta personnel, working through local industrial development groups, are monitoring the possibilities that other occupants will re-open the idle plants and hopefully will resume gas consumption in their manufacturing processes at those currently idle locations. This could have an impact and should be considered by Delta as future gas supply and delivery plans are developed.

The recommended formalized plan for Delta should consider the following elements:

- A long-term (3-5 years) demand forecast for Delta's demand areas, incorporating weather scenarios to assess the amount of resources needed for levels of coverage based on statistical analysis. A forecast that indicates upper and lower bounds designated by considered weather scenarios would allow such planning.

- A long-term capacity development plan for Canada Mountain Storage, indicating potential scenarios regarding how the maximum daily quantity (MDQ) and seasonal capacity quantity (SCQ) will increase over the next 3-5 years.

- A pipeline capacity plan that indicates currently-planned pipeline capacity developments and the amounts that are currently used by transportation customers.

- Identification of system improvements that would be required for Canada Mountain's capacity to be further utilized.

- Identification of the extent to which Canada Mountain storage can supplant storage contracts to serve some of Delta's peak-day requirements in its northern service areas. Since most contract expirations are around 2004, a 3-5 year horizon would be appropriate. This requires a consideration of facilities required to flow gas north.

- A cost/benefit analysis associated with the potential improvements to the system identified from the above steps.

Clearly, this planning must await the results of the analysis mentioned in the previous recommendation. Liberty believes that Commission monitoring of this activity is also essential, and believes that the Company and the Commission Staff should work out a schedule of reporting.

2. Organization, Staffing and Controls

a. Scope

This chapter of Liberty's report addresses the aspects of the Delta Natural Gas Company, Inc. (*Delta or Delta Natural*) management and operations that relate to its overall organization, staffing and controls:

- Organizational Structure.
- Staffing.
- Approval Authorities.
- Work Process Definition and Control.
- Documentation Requirements.
- Auditing.

b. Background

(1) Organizational Structure & Staffing

Natural gas supply planning, procurement and management activities for Delta are handled by the Gas Supply Department, which is one of four departments reporting to the Vice President of Operations & Engineering for Delta. The Vice President of Operations & Engineering in turn reports to the President & CEO of Delta. All of these functions are located in Winchester, Kentucky.

The Gas Supply Department is led by the Manager - Gas Supply, with two Directors reporting to him, the Director – Gas Supply Transportation, and the Director – Gas Control. Essentially all of the planning, procurement and management for gas supply is handled by two individuals, the Manager - Gas Supply and the Director-Gas Supply Transportation who reports to him. Primary responsibilities of the Director-Gas Supply Transportation are to administer contracts and assist in the supply planning process, including development of the long-term forecast. The Gas Control function supports the provision of safe, reliable and economic gas delivery for Delta's customers. All major decisions about policy, strategy and major contracts involve the President, the Vice President – Operations and Engineering, and the Manager – Gas Supply.

Delta has three affiliates, Enpro, Inc., Delta Resources, Inc., and Delgasco, Inc. as discussed in greater detail in Chapter 7, Task Area Seven - Affiliate Relations. All of the employees and officers of Delta Natural also fulfill that same role if required for Delta's affiliates. The President of Delta is also the President of each affiliated company, and the Delta Vice President of Operations & Engineering is also the Vice President of each affiliated company. The result is that some Delta employees can "wear many hats". For example, the Manager - Gas Supply could be involved in gas procurement and management activities for not only Delta, but also for each of the three affiliates. This is also discussed in more detail in Chapter 7, Affiliate Relations.

The senior managers and officers of Delta have been at Delta and in the natural gas industry for many years. Because of the seniority of this group of individuals, and because of the small size of Delta, the company faces the possibility of the loss of significant talent and expertise should any one of these individuals decide to retire, or leave the company for any number of other reasons. Currently, there is no written management succession plan in place to deal with this situation.

Gas Supply Department

The Gas Supply Department performs all of the Delta activities related to the purchase and sale of natural gas, including contract negotiation, the scheduling of gas supply on the interstate pipelines, and the release of interstate pipeline capacity. The function also performs the review and approval for payment of all pipeline and supplier invoices and the generation of invoices related to sales made off system.

Gas Control

The Gas Control function supports the provision of safe, reliable and economic gas delivery for Delta's customers. Performing the Gas Control function requires the maintenance of a Gas Control Center that is staffed 7 days a week / 24 hours per day, which has the ability to monitor and control the flow of gas at critical points on Delta's system on a continuous basis.

The Gas Control function also determines the daily gas demand to be served by Delta so that sales customer's demand can be met in a reliable manner and so that the Company is able to provide gas balancing services to transportation customers, as supplies and weather conditions change.

Performance Measurement

Delta has a formal written performance measurement system and an employee evaluation process that is conducted annually. The basis for the performance management system is two-fold: 1) the job description is the foundation and performance is compared to what the employee is supposed to be doing, per the job description; and 2) the goals and objectives set at the beginning of each year in a mutual session between the employee and his manager. Specific goals are required for the evaluations of all employees, and at the end of each year the manager will determine if the employee accomplished the specific goals set forth at the beginning of the year.

This year a self assessment process for just the officers and those others who report directly to the President was tested. The employees were asked to recommend their individual goals and input on salary. This approach may be expanded to include a broader range of employees in the future.

The result of the evaluations from the performance measurement system is that some people will get raises, but some could not. Also, if funds are available, based on corporate performance, some employees may get a bonus in addition. The President personally reviews the evaluations of all employees. All evaluations have three signatures, the employee, his supervisor, and the next manager up the line.

The downsizings at Delta in past years have contributed to low morale in some employees. In addition, there is the feeling that employees are concerned with how merger trends in the industry might adversely impact Delta.

Training

There is no formal training program, for gas procurement employees at Delta, but attention is paid to training. Training is a priority item for the President, and he has established a specific training component to the Company's budget.

Delta sends employees to Eastern Kentucky University for management training, to pipelines for customer meetings, to industry seminars, and outside experts are brought in on a regular basis to talk about management and self-improvement issues. The President gives special emphasis to management training, with focused classes presented for managers to help them deal with difficult situations in the workplace. Some of the typical goals in the performance management system are tied to training accomplishments.

Some cross-training does occur at Delta. For example, the Director – Gas Control is now learning right-of-way work, and the dispatchers from Gas Control are being taken to the field for specialized cross-training so they will better understand how field operations are linked to Gas Control operations. However, as mentioned earlier, there is no formal cross-training program.

Because Delta has experienced two downsizing reductions in staff of about 12% each the current staff has had to learn to do more. Cross-training has played a part in expanding staff capability in some areas. The President is concerned about teamwork and has begun to introduce the team concept. Duties for some of the jobs eliminated in the downsizing are being picked up by a team of people, instead of one person, to avoid compartmentalization, and to help in the cross-training process.

Job Descriptions

Job descriptions for employees involved in gas planning, procurement and management functions at Delta are current, and form the basis for the performance measurement system. These job descriptions describe the responsibilities of the positions for which they were written and are updated as necessary to reflect changing conditions.

(2) Approval Authorities

Delta does not have any formal decision matrix, or a list of approval authorities. Delta has a formal budget process and all revenue, expense and capital expenditure accounts are assigned to one of Delta's officers, depending on the areas of responsibility. Invoices are approved by the appropriate officer for those accounts assigned to that officer. The President is involved in major decisions as necessary, and beyond that, Delta employees state that because the company is small, and run on an informal basis, they can visit with the President as necessary for guidance on issues or to keep him informed. Thus, there is a general consensus that no further written procedures are necessary.

(3) Work Process Definition and Control

The operations of the gas planning, procurement and management functions at Delta are not guided by formalized, written policies and procedures. Delta has stated that the overriding guidance for how to do things comes from the Strategic Plan, which is prepared each year, and which has considerable detail as to what each person is responsible for accomplishing.

As indicated above, the feeling throughout Delta is that written procedures are not required because the Company is small. Employees feel that they can visit with the President and ask for guidance if they are unsure of what the procedure should be for something, and they know that if there is a major decision to be made, the President will be involved as necessary.

Delta does have a cost allocation manual (CAM) that has been filed with the Commission. However, this manual does not provide sufficient detail for dealing with affiliates, and there are no specific procedures related to affiliate relations.

Delta does not have any written procedures for risk management. As with many issues at Delta, employees look to the President for guidance, and this is true in the area of risk management as well.

Liberty has concern with certain protocol issues related to how business is handled between affiliates. Kentucky Statute (KRS 278.2213) has very specific requirements related to affiliate transactions, including the requirement on how Delta should handle inquiries from potential customers of an affiliate as to where that customer should take his business. The requirement is that a utility shall notify the customer that competing suppliers of a non-regulated service exist if the utility receives a request for a recommendation from a customer seeking a specific service which is offered by the utility's affiliate or by the utility itself, and the utility mentions itself or its affiliate when making the recommendation to the customer. The supervisor of the individual responsible for these activities was not completely familiar with the referenced Kentucky Statute. This subject is covered in detail in Chapter 7, Task Area Seven - Affiliate Relations.

(4) Documentation Requirements

Documentation of gas procurement and supply management activities within the Gas Supply Department could be improved in some respects. For example, Liberty examined the process of splitting of invoices containing gas bought by two Delta entities to understand how they were split and whether or not the split was appropriate. While the invoices did contain calculations to explain the allocation of dollars to the two Delta entities, the backup support contained in computer files is not printed out so that it can accompany the invoice to both Accounting for journal entry and to Treasury for payment. Further, after a few months, the computer files directly linked to these invoice allocations, and supporting them, are deleted. Thus, after a few months, backup support necessary for any cross-checking or audit verification will not exist.

Hard-copy support for all orders does exist in the form of order confirmations (Exhibit A from master contracts) but these are not attached as backup to invoices sent to Accounting or Treasury, and are not directly linked to the calculations made on the computer spreadsheets that actually support the invoice allocations. The subjects of invoice splitting and hard-copy support for invoices are covered in detail in Chapter 7, Task Area Seven - Affiliate Relations.

Delta's gas procurement group, including supply, dispatch, transmission and storage, meet on a regular basis (monthly or more often as needed) to plan, discuss performance and objectives and to take actions to modify plans where necessary. The President joins them for some of those meetings.

Communication within Delta on important issues is facilitated by a number of processes and meetings. On a weekly basis, the President holds staff meetings with the officers and the Chairman of the Board. Each participant updates the whole group on activities in their areas over the last week, on budgets, on personnel issues, and anything else of general interest.

The President meets with management and all supervisor personnel at least 2 times per year for training and to discuss the Company's business and any matters of general interest. There is also a December meeting with all employees; one purpose of this meeting is to provide updates on what is happening in the company, give direction on important issues, and also to receive feedback from employees.

The President works to maintain a constant flow of communication on important topics throughout the Company using both written communications and email. He also writes a column in the Delta Newsletter three times per year, and writes the quarterly shareholder letter.

Delta does have a Strategic Plan that is prepared annually and used throughout the year as the guide for Company operations. Company philosophy is to react to the plan as the year progresses, and not consider the plan to be fixed in stone. While the plan is not actually modified during the year, management feels free to change the plan as they go along if they see that actions not specifically provided for in the Plan need to be taken.

Each year, the new Plan is reviewed at a meeting with the Board, and compared to the previous Plan. The President is the facilitator of these meetings. The Plan he presents is one that attempts to incorporate how the world is changing, in all aspects of their business, from national policy to regulatory issues, to more specific pipeline issues. Generally, these planning meetings include the Board and some or all managers and supervisors. These meetings generally last all day, and are generally held outside the main office so there will be fewer disruptions. At the conclusion of the day, Delta has the essentials of a new Plan; this then leads Delta into the budgeting process for the next year. The budgets are prepared in detail, and include both capital budgets and expense budgets, as well as the 5 year forecast of these items.

As each year unfolds, the President reports to the Board each quarter on the Company's performance and plans are adjusted as necessary.

(5) Auditing

One internal audit of the gas procurement function has been conducted at Delta over the last five years. This internal audit reported several discrepancies related to gas accounting complexities, duplication of effort, and manual entry of data that should be computerized.

In response to this, the Company formed an internal working group, chaired by the Controller, and met monthly through the summer and fall of 2000 to explore the problems identified. Each department flow charted their information processes and explained their charts to the working group. That exercise resulted in streamlining of the processes in the three departments. Two different employees assigned to implement the loss reporting changes from the working group left the Company and as a result that area has yet to be completed. Delta has not felt it necessary to obtain outside help for implementation in this particular instance.

The Company uses the retired former controller on an independent contractor basis for the internal auditing function. This individual also performs a number of other functions for Delta, including preparation of tax returns and regulatory filings.

Each year, the internal auditor prepares a three-year plan of proposed areas of investigation on a Company-wide basis. He and the President then work together to decide what areas of the Company need the focus of an internal audit. The internal auditor reports to the Board Audit Committee, consisting of four Board members, in addition to reporting to the President. On an annual basis, the internal auditor makes a written report to the Audit Committee and the Audit Committee reviews and approves his work and plans for future audits. From time to time, the internal auditor meets with the firm's outside auditing firm to review auditing plans and prevent overlap in the auditing conducted by each part.

c. Conclusions

(1) Delta does not have any written policies or procedures governing the planning, procurement or management of natural gas operations, including those for dealing with affiliates, and for risk management. (*Recommendation #1*)

In general, Delta operates with informality, with no written procedures. If there is uncertainty on an issue, employees feel free to visit with the President or the Vice President – Operations & Engineering to obtain resolution.

Employees feel that because of the longevity of senior management and Delta's smaller size, written procedures are not required. While employees state that they have procedures for the operations of gas planning, procurement and management, these procedures are not formalized in written form. The obvious disadvantage of this situation is that should one of these senior employees become unable to perform their responsibilities, or decide to leave the company, there could be a considerable void in the experience base and the knowledge of how to perform the basic functions related to gas supply.

(2) Delta does not have a formal decision matrix, or chart of authorities that defines the responsibilities and authorities of various levels of management within the company. (*Recommendation #2*)

As with the issue of procedures for management of gas supply operations, personnel at Delta feel they understand who can make decisions at Delta, and what their limits of authority really are. However these limits of authority are not formalized in any formal document other than the budget and invoice approval process. The lack of formalized documentation is especially significant in the area of risk management, where it is important for both the President and the Board to define and approve the level of risk to which the various levels of management can commit the company.

(3) Delta does not have a written plan to address the possible departure of its senior management personnel. (*Recommendation #2***)**

The senior managers and officers of Delta have been at Delta and in the natural gas industry for many years. Because of the seniority of this group of individuals, and because of the small size of Delta, the company faces the possibility of the loss of significant talent and expertise should any one of these individuals decide to retire, or leave the company for any number of other reasons.

(4) Company downsizings have had a negative impact on employee morale and the ability of the various departments to work effectively together as a team. (*Recommendation #2*)

Several senior managers at Delta reported that low morale is an issue at the Company. Certainly the two downsizings of 12% each contribute to this situation. In addition, there is the feeling that employees are concerned with how merger trends in the industry might adversely impact Delta.

Another natural consequence of downsizing in any business environment is that employees feel threatened and feel that they must control as many aspects of their own job functions as possible in order to appear indispensable. This leads to natural tendencies to not share in work responsibilities, and to not operate as a team, as much as management would prefer that employees pull together as a team even more in the face of reduced numbers. Delta management has tried to stimulate the team spirit, but Liberty believes cooperation and communication between the various functions at Delta could be improved. Within specific functions, teamwork did appear, but it did not appear to exist across functional boundaries.

Some managers at Delta felt that because the company was small, teamwork was a natural outcome. At the same time, these same managers reported problems in getting the employee group to work together as a team. One expressed it as difficulty in getting employees to work on the same sheet of music. Clearly, there is a contradiction between the lack of team spirit observed both by Liberty and some managers, and the notion expressed by some that because Delta is small its employees operate as a team.

(5) Delta has not completed work on productivity improvements necessary to implement the recommendations from the internal audit of 1999. (*Recommendation #3*)

An internal audit conducted in late 1999 reported concerns related to gas accounting complexities, duplication of effort, and manual entry of data that should be computerized.

In response to this, the Company formed an internal working group, chaired by the Controller, and met monthly through the summer and fall of 2000 to explore the problems identified. Each department flow charted their information processes and explained their charts to the working group. That exercise resulted in streamlining of the processes in the three departments. Two different employees assigned to help implement certain results achieved by the working group left the Company and as a result some intended objectives have yet to be achieved. While the findings of the internal audit have presented the possibility for improvement in the operations at Delta, the Company plans to complete this with existing staff as opposed to obtaining outside help for implementation.

(6) Delta has an effective Strategic Plan and planning process.

Delta has a Strategic Plan that is prepared annually and used throughout the year as the guide for Company operations. While the plan is not actually modified during the year, management feels free to change the plan as they go along if they see that actions not specifically provided for in the Plan need to be taken.

Each year, the new Plan is reviewed with the Board, and updated from the previous Plan. The President is the facilitator of these meetings. The Plan he presents is one that attempts to incorporate how the world is changing, in all aspects of their business, from national policy to regulatory issues, to more specific pipeline issues. Generally, these Planning meetings include the Board, as well as some or all managers and supervisors. These meetings generally last all day, and are generally held outside the main office so there will be less disruptions. At the conclusion of the day, Delta has the essentials of a new Plan.

As each year unfolds, the President reports to the Board on how the Company is doing, and any changes he feels need to be made.

d. Recommendations

(1) Develop formalized policies and procedures covering the normal functions of gas planning, procurement and management, including procedures for dealing with affiliates, and for addressing risk management. (*Conclusion #1*)

The Gas Supply Department should begin a program to develop formalized, written procedures covering all aspects of gas supply planning, procurement and management activities. These procedures should provide sufficient detail of necessary actions and assignment of responsibility for these actions such that they can be used both for training of new employees, and cross-training of existing employees.

Procedures should be developed to cover affiliate relations and activities, and the necessary controls with affiliated organizations and other Delta entities dealing in activities in unregulated areas. Specific care must be taken to ensure that procedures deal with necessary controls in areas where cross-subsidization could occur.

Risk management procedures should be developed to provide a complete picture of the areas of risk to which the Gas Supply Department is exposed, assignment of specific responsibilities for activities in these areas and establishment of appropriate functions for management review and control of risk related activities.

The area of risk management is complex, and in many cases new to natural gas utility operations. Therefore, Section I.B of this report contains the outline of a typical Risk Management Policy.

(2) Develop a management succession plan for the gas procurement area that integrates cross-training, new definitions of responsibility and authority with delegation at the lowest possible levels in the company, and a performance management system that rewards for individual performance in these new levels of delegation. (*Conclusions #2, #3, #4*)

Delta should document a management succession plan for the gas procurement area and the necessary systems and procedures that recognizes the vulnerable position of being small, and the necessity to structure the organization in new ways for more effective operations.

The first step must be a training plan for gas procurement employees in the Company that addresses both the dimensions necessary to orient new employees and also the importance of cross-training in order to better prepare the Company for employee absence due to illness, injury or retirement. One of the benefits of formalized cross-training will be to better familiarize the gas procurement department of Delta with the operations of other departments; this improved understanding will lead to better teamwork between these departments.

An important component of the new policies and procedures should be a decision matrix, or list of authority limits. This document should detail the magnitude of decision that can be made by each level of management. In preparing this document, every effort should be made to push responsibility and authority down into the organization as far as possible.

Finally, Delta should hold individuals accountable in their performance evaluations for performance at any increased levels of responsibility and authority.

(3) Outsource as necessary to facilitate needed streamlining of accounting systems, data management and information flows, and to facilitate resolution of other problems as they arise. (*Conclusion #5*)

Delta should consider the advantages of outsourcing of certain activities in order to bring about more timely implementation of needed improvements to the overall organization. The use of internal resources has not resulted in timely implementation of all needed improvements identified in the internal audit conducted in 1999, although some progress has been made in implementing recommendations in this area.

The basis for all outsourcing should be a cost/benefit analysis conducted internally that examines the various alternatives for problem resolution along with the associated costs and benefits of each approach. Ultimately, Delta should be able to prioritize its options. At the same time, Delta can develop instructive internal approaches to problem solving that teach employees that flexibility is important, that there is no one set approach to problem solving that must be used, and that use of outside resources is not a negative reflection of internal job performance. Instead, there should be positive value in recognition of the benefits of comparing alternative solutions to problems, and choosing the option that is most effective in meeting the overall needs of Delta.

3. Gas Supply Management

a. Scope

This chapter addresses Delta's management of its gas supply portfolio. Topics addressed include the following:

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Renegotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management.

b. Background

(1) Existing Gas Supply Portfolio

Delta's capacity portfolio consists of pipeline capacity on the Columbia Gulf, Columbia Transmission and Tennessee Gas Pipeline systems. Key parameters for those contracts are given in Table 3.1 below.

Table 3.1 Delta Natural Gas Pipeline Capacity Portfolio

	Tennessee Gas P/L Sched. FT-A & FT-G MDQ (Dth)
Jan	20,111
Feb	20,111
Mar	15,450
Apr	10,475
May	7,550
Jun	5,676
Jul	5,648
Aug	5,648
Sep	5,826
Oct	9,244
Nov	14,475
Dec	20,111

	Columbia Gas Transmission P/L Sched. GTS	Columbia Gulf Transmission P/L Sched. FTS-1
Transportation MDQ, Dth/Day	17,013	4,378
Storage SCQ, Dth	425,773	
Annual Quantity ACQ, Dth	288,175	

Delta serves its Southern System, which accounts for about half of its load, from its Canada Mountain storage facility. Gas is purchased off the Columbia Gulf pipeline to supply summer system requirements and to inject into the Canada Mountain storage facility over the summer months, and then is withdrawn to serve the winter load in that area. Delta also has about 1,000 customers in its southern service territories that are served from gathering lines owned by Columbia Natural Resources, Columbia's Appalachian-area gas-production and gas-gathering affiliate. Gas is also purchased from other local producers in that area, and taken into Delta's Southern System after proper conditioning and compression.

Delta's Columbia Gulf contracts have two-part rates. Delta's contracts on Columbia Gas Transmission have one-part rates. Consequently, Delta only pays for the amounts of capacity that it actually uses (subject to minimum annual quantities, set to ensure a minimum contribution to recovery of the pipelines' fixed costs). Delta's contracts on Tennessee Gas Pipeline provide for two-part rates, but the amount of capacity under contract is sculpted over the course of a year – reduced in the summer months – so that the capacity being paid for declines in the summer months.

Delta uses city-gate supply-service contracts for the gas that it requires to serve its customers in its northern service territories. Under these arrangements, the selected suppliers are given full and complete control over the utilization of the pipeline and storage capacity that Delta has under contract. The supplier manages the capacity as it sees fit, but is responsible for supplying Delta's needs at the city gate, whatever those needs are up to the maximum pipeline contract capacity for each respective month. One marketer serves Delta's city gates on the Tennessee Gas Pipeline system, and another serves its Columbia city gates.

Gas for the Southern System is bought mostly from a third supplier at the Speedwell Purchase Station on the Columbia Gulf pipeline. Delta does not have delivery rights on Columbia Gulf for that supply, but transportation capacity for Delta's supplier has never been curtailed or interrupted during the summer storage injection season. Delta acquired the pipeline connection with its purchase of the Tran-Ex pipeline system. Delta's supplier for much of the gas delivered to that point does have access to transportation to that point, however, and gives Delta an attractive price for gas delivered there.

(2) Supplier Identification and Qualification

Delta mostly does business with the same suppliers from year to year. M&B Industrial Gas Supply provides most of the gas for injection into storage because of its favorable delivery arrangements via Columbia Gulf (making the delivered cost to Delta attractive). Delta gets lots of inquiries for this business, as it easy to provide – spot-market gas during the summer months – but Delta feels that it gets good service at an acceptable price from M&B.

Delta has been using Dynegy, the successor to Natural Gas Clearinghouse, as its supplier for its service areas supplied from Columbia since the implementation of the FERC's Order 636. Delta worked with a small-customer group on the implementation process, and was introduced to Dynegy in that context. Dynegy originally sought the business of the entire group, but was willing to work with individual companies when the group could not agree to consolidate its purchases.

Delta originally worked with Duke Energy Trading and Marketing's predecessor, Tenneco Gas Marketing, for its Tennessee-supplied areas. The background of that relationship was similar, that involved introduction via a small-customer group for the Tennessee system. Delta conducted a competition for its TGP supply during the first half of 2000, however, and received better terms from the current supplier, Woodward Marketing.

Delta does not have a supplier qualification process *per se*. Delta's Gas Supply Department is in the market all the time, however, looking for supplies for Delta Resources's customers. Thus, Delta feels that it has a good handle on the list of reliable suppliers that are active on its pipelines. Delta's recent (2000) request for proposals for supply to its Tennessee service areas was sent to six potential suppliers, including both Duke and Woodward.

(3) Identification of Acquisition Needs

Delta prepares a long-term forecast every year. That forecast is used for the adjustment of contract quantities (pipelines and suppliers) as necessary. Requirements are forecast by different categories including company usage and customer class (one residential and two commercial classes), and are adjusted for new markets as necessary. Delta's Columbia contracts are fixed until 2004. Its Tennessee contracts, which were increased to accommodate load growth several years ago, run until 2005.

For operation of its agreements with its gas suppliers, Delta uses an annual supply plan that is updated every month. Each month, Delta provides estimates of the next month's requirements, in time for the suppliers to make monthly nominations to the pipelines. These estimates are made on an average-day basis, with day-to-day usage variation within each month managed with storage, plus Delta's operational balancing agreements with the pipelines. The suppliers are responsible for day-to-day nominations to the pipelines.

(4) Negotiation and Renegotiation of Contracts

As noted above, Delta's Columbia Gas Transmission contracts are fixed until 2008. Because Delta pays a one-part rate, based only on its actual usage, however, Delta's customers are not paying for capacity that they might not be using. On Tennessee, Delta has had to increase its contract capacity somewhat to meet the demands resulting from growth of its TGP-supplied systems.

As also noted above, Delta's supply contract with Dynegy, and its spot-gas purchasing arrangement with M&B, have been in place for some time. Delta's requirement for supply on Tennessee has recently been re-competed, in the hope of improving the terms for that supply.

Delta is considering whether to re-compete the Dynegy contract, which had an initial multi-year term, but is now being extended year to year.

(5) Contract Terms and Conditions

Contracts for pipeline capacity are service agreements under FERC Gas Tariffs. Delta uses a Gas Industry Standards Board (GISB) contract for its purchases of spot gas for injection into storage. The contracts with Dynegy and Woodward are those firms' contracts.

(6) Peak Period Performance

No delivery problems were experienced during the winter of '00/'01. Facilities associated with full operation of the Canada Mountain storage field are designed and operated to supply the peak-day requirements of the Southern System, as well as its winter-period requirements. Sufficient gas is kept in the storage field until early February to ensure that a peak day can be met from that resource alone. Moreover, Delta retains 5,400 Mcf/day of delivery capacity from Columbia Transmission at the Greenbriar Purchase Station that could be used to supplement deliveries from the storage field, if necessary.

(7) Price Risk Management

With access to its storage field for about half of its annual system-supply requirements, Delta is able to reduce the effects of high winter gas prices by buying gas in the summer and injecting it into storage. Moreover, Delta's contracts with both Dynegy and Woodward provide a fixed-price option, whereby Delta can lock in prices for one or more winter months in advance. Between these two devices, Delta has been able to hedge the price of 50 to 70 percent of its supply. Because Delta uses a blended gas price for all of its system-supply customers, the benefit of these hedges accrues to all of them.

Storage injections have occurred roughly uniformly over the summer. Delta's decision whether to lock in prices for the winter months have generally been made in the fall, after observing whether prices for those months, as indicated by futures contracts traded on the New York Mercantile Exchange (NYMEX), were increasing. If so, Delta would generally lock in for the winter months for a quantity equal to what the Company would expect to purchase during a relatively warm winter. Summer injections plus the warm-winter quantity would enable the Company to avoid buying at winter-period prices for most of its supplies, without over-committing its requirements.

The Company does not have written risk-management policies and procedures for its gas supply, as discussed in detail in Chapter 2, Organization, Staffing and Controls. Decisions regarding advance purchases, or locking in prices for future months, are made by a group composed of the Vice President for Operations and Engineering, the Manager of Gas Supply, and the Director of

Gas Supply and Transportation. The Director of Gas Supply and Transportation analyzes price information and makes purchase recommendations to the group. The President is involved as necessary.

c. Conclusions

(1) Completion of major new facilities requires a fresh look at how Delta supplies its customers. (*Recommendation #1*)

Delta embarked on the Canada Mountain storage venture out of concern for supply to its Southern System. When development is completed, the field may have enough capacity to serve other needs if the final developed capacity continues to increase toward the theoretical design capacity. Extra capacity available for non-sales customers does not exist now, but could possibly be as high as 2.4 Bcf, assuming the field develops to its theoretical capacity. Some Delta personnel have suggested that a possibility for use of that additional capacity would be to displace the storage services that Delta buys for its sales customers on its northern systems if facilities could be added to allow gas to flow north. Other possibilities mentioned to Liberty include offering storage services to Somerset Gas system, with whom Delta's system is interconnected, and current customer Citizens Gas Utility in Tennessee.

Additional possibilities that occur to Liberty include offering storage and balancing services to Delta's on-system customers, and perhaps to customers on the Columbia Gulf and Columbia Transmission systems and on Tennessee Gas Pipeline. Local producers who sell into Delta's system may be willing to purchase a back-up service from Delta to be used in the event of freeze-offs. Delta reports that, while both the storage development and high-pressure connection projects have been under way for some time, there currently is no concrete plan for evaluation, use, or marketing of unused capacity on those facilities as there is no extra capacity available at present.

Delta's contracts with Columbia Gulf and TCO expire in 2008. Delta's Tennessee contracts automatically renew for five years in 2003 unless terminated by either Delta or Tennessee.

As noted in Chapter 1, Gas Supply Planning, Delta's storage and facilities upgrades are not complete, and considerable testing remains to be done to determine how much incremental capacity might exist. Hence, Delta has not developed plans nor entered contracts for using any capacity as such capacity has not been available. As testing is completed and the System's capabilities become clear, Delta should begin a comprehensive evaluation of its customers' requirements in relation to those capabilities, and make plans for marketing any capabilities that are in excess of those requirements.

(2) Delta's "hedging" programs need more study.

As noted above, Delta did not file a hedging program, but it took certain actions during the winter of '01/'02 to hedge its gas costs; it "locked" its winter prices under its contracts with

Woodward and Dynegy. As also noted above, Liberty feels that all five of the Kentucky LDCs and the Commission need to work together to establish some objectives for their hedging activities before further activities are undertaken. As discussed in this report, Liberty also feels that Delta's gas-cost accounting, particularly that between Delta and its unregulated affiliates, needs further analysis.

d. Recommendations

(1) Delta should report to the Commission on the continued development of its storage and transmission capabilities, and on its plans to market capacity if and when available. (*Conclusion #1*)

In Chapter 1, Gas Supply Planning, Liberty recommended that Delta report to the Commission on the nature of and timetable for facilities testing. Liberty also recommended that, when that report was complete, Delta should meet with the Commission Staff to discuss its findings to date, and its plans for further evaluations.

Liberty recommends that the discussion also include the Company's plans for developing storage and transmission facilities and identify any storage and transmission capabilities that become in excess of its customers' needs, and plans for marketing those capabilities to the extent feasible. As with the report discussed in Chapter 1, the Company and Staff should also discuss at that time appropriate further reports by Delta on its progress.

(2) Delta should work with the Commission, other Kentucky LDCs and interested parties to establish a common foundation of objectives for natural gas hedging programs. *(Conclusion #2)*

As discussed in the first section of this report, Liberty believes that the Commission, the LDCs and other interested parties should review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. The Columbia Distribution Companies, whose gas-supply operations are also conducted on a centralized basis, had hedging programs in three of the five States in which they operate. (Kentucky is one of the five, but not one of the three.) Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management.

Liberty recommends that a specific area for discussion be the objectives of future hedging programs. In this vein, Liberty applauds the Commission's decision that public input be sought in selecting those objectives. Liberty's experience tells us that different customer classes will prefer different objectives. That knowledge will help the Kentucky LDCs to tailor their service offerings more closely to their customers' requirements.

4. Gas Transportation

a. Scope

This chapter addresses Delta's natural gas transportation programs. Topics considered include the following:

- Transportation Programs Offered
- Agency Programs
- Bypass Issues
- "Prodigal Son" Customers

b. Background

(1) Transportation Programs Offered

Delta provides gas transportation for both on-system and off-system use. On-system transportation is available to small non-residential, large non-residential and interruptible customers who have purchased their gas from a third party, and who seek to move an average daily volume of at least 25 Mcf to a location that is connected to the Company's facilities. The charge for this service is the Company's Base Rate, as set forth in its Tariff. Those rates start with $3.6224 per Mcf for firm service, and $1.60 per Mcf for interruptible service.

Off-system transportation is available to any customer whose facilities connect to the Company's facilities, and who wants to deliver gas to a place of use not connected to the Company's facilities. This service also has a minimum daily volume of 25 Mcf. This service is interruptible, and the charge for it is 26 cents per Mcf.

Transportation-service customers pay a two-percent retainage to cover line loss and measurement differences when no compression is required for the customer's gas to enter Delta's facilities. If compression is required, additional retainage is required to cover compression fuel.

Table 4.1 (below) provides the number of customers and volumes moved for both kinds of transportation service.

Table 4.1 Transportation Customers & Volumes

	2001	2000	1999	1998
On-system Customers (Avg.)	94	94	90	91
On-system MCF Transported	4,692,977	4,865,847	4,486,492	3,903,095
Off-system Customers (Avg.)	4	4	4	3
Off-system MCF Transported	1,949,522	1,004,685	999,372	1,404,111

(2) Agency Programs

Delta does not have agency programs *per se*. Instead, Delta has an affiliate, Delta Resources, that provides on-system supply services for commercial and industrial customers. Delta Resources serves about 40 customers, with gas-supply options tailored to each customer's requirements. A number of those customers buy gas at prices that are fixed in advance of the purchase period.

Delta Resources arranges for supply for each customer, and arranges for transportation on Delta's system to the customer's location. In general, Delta Resources buys gas delivered to Delta's city gates, and then has Delta deliver the gas to the customer under the terms and conditions of Delta's On-System Transportation tariff.

To date, there have been no issues among Delta's different groups of customers about priority of access to particular facilities. The last service interruption on Delta's system was in the 1970s. The networked nature of Delta's Southern System, in particular, would ordinarily make access-to-facilities issues unlikely.

(3) Bypass Issues

Delta is threatened with bypass from time to time. Principal threats come from industrial customers in the north that are close to interstate pipeline facilities (particularly Columbia Gulf), and from local producers in the south, who seek to lure Delta's customers away to local production.

Delta deals with bypass threats as they occur. Delta has offered gas transportation services since the 1980s, and those services are its best weapon against bypass. Delta has entered into special contracts at less than tariff rates for larger-volume industrial customers on its northern systems when necessary to avoid bypass. Delta has received help from the Commission in asserting service-area rights in the south. To this point, Delta has not lost any customers to bypass.

(4) "Prodigal Son" Customers

Delta has had a problem with "prodigal son" customers, *i.e.*, customers who switch to transportation service and then switch back to system supply. Delta recently changed its tariff to require a minimum period (one year) prior to switching back, in order to limit customers' ability to game the system by more-frequent switching.

c. Conclusions

(1) Delta's current gas transportation programs are reasonable.

The very large difference between Delta's rates for on-system and off-system transportation services would seem to present a tempting target for manipulation. Liberty's sense, however, is that the rates charged reflect legitimate differences in the value of the different services being provided. Delta personnel also report that the price charged by competing providers of services that are similar to Delta's off-system transportation (primarily Columbia Natural Resources) is the same as Delta's (26 cents per Mcf).

Liberty also shares Delta's view that any revenues from incremental transportation services are welcome offsets to the revenue requirement that must be assessed to utility services.

(2) Off-system transportation and related services may offer significant opportunities for revenue growth. *(Recommendation #1)*

The table presented above shows that off-system transportation volumes have grown significantly over the last four years. Delta reports that the growth in that category continued into 2002.

Liberty observes that Delta's location offers the possibility of a strategic link between the large amount of interstate pipeline capacity in Kentucky and capacity-constrained gas markets in eastern Tennessee and western Virginia. Especially with the addition of storage services, Delta may be able to add considerable volumes and revenues by providing transportation services, which may be by displacement, across this link.

d. Recommendations

(1) Delta should include in its reports to the Commission its assessment of potential markets for transportation services between pipeline systems. (*Conclusion #2*)

As noted in earlier chapters in this section, Delta is continuing to evaluate the capabilities of its facilities to provide services to on-system and off-system customers and has continued to expand its transportation business. Liberty has also recommended earlier that Delta keep the

Commission informed of its progress on those evaluations. In repeating our recommendation for reporting to the Commission, Liberty simply means to draw attention to the possibility for high-value services in providing a link between pipeline systems. Liberty recommends that such services continue to be evaluated by Delta, as changes occur with its facilities and as capabilities for additional services arise, and that the results of these evaluations be included in the reports previously recommended.

5. Gas Balancing

a. Scope

This chapter addresses Delta's means and methods for balancing its gas delivery system. Topics addressed include the following:

- Metering and Testing
- Balancing Strategies and Practice
- Assignment of Capacity to Third Parties.

b. Background

(1) Metering and Testing

For Delta's northern service areas, gas enters Delta's systems through purchase stations on the interstate pipelines, where it is metered. Gas leaves those systems through customer meters. For each of the systems, the sum of the meter readings going out should match the meter reading coming in.

Gas movements in the Southern System are more complex. Local production, including volumes from Delta's affiliate Enpro, enters the System; gas is injected into and withdrawn from the Canada Mountain Storage Field; gas comes in via the Tran-Ex pipeline; and gas leaves via Columbia Transmission's KA-1 transmission pipeline, the City of Jellico, Tennessee and Citizens Gas Utility District. Some of Delta's customers are served from gathering lines owned by Columbia Natural Resources, but those lines are not connected to Delta's System. As a consequence of the more complicated movements, Delta maintains a number of measurement points on the Southern System, in addition to metering gas going in and out.

The Southern System also has a number of gas uses. Local production must be dehydrated and compressed, for example. Delta meters all Company uses, except for some small uses that are estimated.

Delta has written procedures in its Operations and Maintenance Manual for periodic meter testing, and for meter testing in response to customer requests. These procedures were developed pursuant to Commission regulations, and are reviewed and approved by the Commission. As it does for all jurisdictional utilities, the Commission also inspects and tests Delta's meter-testing equipment periodically.

Delta's lost-and-unaccounted-for volumes (LAUF) are estimated by comparing the difference between the total of meter readings for gas going into Delta's facilities, to the total of meter readings for gas going out, adjusted for company-use gas and any known imbalances. This comparison was done on a system-by-system basis until 1999, but is now done on an aggregated basis. The LAUF percentage at June 30, 2001, was estimated to be 1.9 percent.

Transportation-service customers pay a "retainage" as their share of LAUF volumes. That retainage is currently 2.0 percent.

(2) Balancing Strategies and Practice

Balancing for system supplies is accomplished through Delta's operational balancing agreements (OBAs) with its supplying pipelines or through Delta's storage capacity on the interstate pipelines. Nominated transportation volumes are considered "first through the meter" – *i.e.*, it is assumed that deliveries for transportation gas equal nominations. The difference between the total amount received at each city-gate station, and the total of quantities nominated by transportation customers, is counted as system-supply volumes.

Balancing for transportation customers is accomplished by comparing metered deliveries to these customers to their nominations physically delivered to Delta. Delta's Director- Gas Supply and Transportation keeps monthly records that track this information for on-system customers. Delta's Director- Gas Control keeps balance sheets for off-system transportation. For larger-volume customers, delivery meter data is telemetered in to Delta's office, so that the comparisons between nominations and deliveries can be tracked daily.

The Company offers a Stand-by Sales Service to transportation-service customers. In general, this service is provided under contract to customers who request it. All imbalances are settled at the Company's General Service or Interruptible Sales rates, however, depending on the nature of the transportation service that the customer receives.

For system supply for Delta's northern service areas, Delta is required to nominate to its full-requirements suppliers only daily average quantities for each month. The difference between the daily average quantity and Delta's actual take each day is made up either by injections into or withdrawals from Delta's storage through its storage capacity rights on the pipelines, or by a temporary imbalance within the tolerance of the Company's operational balancing agreements with the pipelines. Balancing the Southern System is accomplished by comparing all meter readings of gas flows into the System (including on-system storage withdrawals) with all meter readings of gas flows out of the system, including on-system storage injections.

(3) Assignment of Capacity to Third Parties

In the Company's contracts with its full-requirements suppliers, Delta assigns its firm interstate pipeline transportation and storage rights to the supplier, and the supplier is responsible for using those rights to meet the Company's needs.

c. Conclusions

(1) Gas accounting needs to be improved. (*Recommendation #1*)

As noted in Chapter 2, Organization, Staffing and Controls, an internal audit, conducted in late 1999 and early 2000, found some issues in the ways in which gas volume and cost information was being managed. The same information was being handled by several different departments within the Company, and was being re-entered into different systems for different purposes. In addition to concerns about duplication of effort, the audit found that certain information about supplier costs and volumes was not easily checked, and thus was not being checked routinely, increasing the possibility of errors being introduced into it. Indeed, some errors were found in the course of the audit.

During calendar year 2000, a group from several departments was formed within the Company to address these concerns. By the end of the year, each department represented on the committee had developed flow charts of their respective handling and use of the information, and had presented the charts to the other members of the committee. Each department made improvements in its own operations as a result of understanding better the information needs of the others, and what form their information was in. Access to data residing on systems in each department was provided to the others, in order to facilitate information flow.

The Company has explored, to some extent, the feasibility of developing a common database for gas cost information that would serve all areas and eliminate multiple entry, and plans to continue to consider that as an option. Meanwhile, some informal cross-checks of gas price and volume data are being used to watch for errors.

Liberty's concern is that this area has not had sufficient priority or urgency to be completed. It needs to be.

(2) Lost-and-unaccounted-for (LAUF) accounting could be improved. (*Recommendation #1*)

Delta's northern service territory is composed of a number of small sub-systems connected directly to pipelines, and not connected to each other. The Company reports that, until 1999, LAUF was tracked on a disaggregated basis. The computer system on which LAUF was tracked was not Y2K compliant, however, so it had to be changed.

Since that time, LAUF has only been tracked on an aggregated (system-wide) basis. The sum of all measurements of gas going into Delta's systems are compared to the sum of all measurements of gas going out, adjusted for known imbalances, as part of closing the Company's books at the end of its fiscal year (June 30).

The Company knows that this calculation is not sufficiently precise, and that it may be masking a measurement problem affecting one (or more) of Delta's sub-systems. This approach has yielded an answer within the acceptable range (2 percent or less), however, and Delta's Engineering Department is confident that its system does not leak. Thus, LAUF accounting, like other aspects of gas accounting, has yielded to other priorities.

d. Recommendations

(1) Developing and implementing improvements to gas cost and volume accounting systems and procedures, including those for LAUF accounting, should become a higher priority. (*Conclusions #1 & #2*)

The Company knows what to do in this area; the problem is a lack of sufficient priority. This area needs to become a higher priority.

6. Response to Regulatory Change

a. Scope

This chapter addresses Delta's response to the changes that have occurred (and are occurring) in Delta's business and regulatory environment. Topics addressed include the following:

- Changes in Objectives for Supply
- Changes in Supply Activities
- Capacity Cost Reduction.

b. Background

(1) Changes in Objectives for Supply

The most marked changes for Delta in its objectives for the conduct of its gas supply function have come in the wake of the Company's decision to replace the historical source of supply for its Southern System with a Company-owned storage facility. Delta acquired portions of the Southern System from a local gas producer (Wiser Oil Company) in the early 1980s. Supply for that system, which has largely been physically isolated from Delta's northern properties, was provided by Wiser under a long-term contract that was scheduled to expire in 1999. The Southern System's only other source of supply was a connection to Columbia Gas Transmission, via the Greenbriar Purchase Station, that was too small to serve the Southern System's full requirements.

Out of concern for the prospects for Wiser's continued performance, Delta performed extensive studies of its options for alternative sources of supply. Details of those alternatives, plus extensive evaluations of the Canada Mountain Storage Field, were presented to the Commission in a proceeding to consider whether Delta should acquire and develop the field. Delta recommended that option to the Commission, and the Commission approved Delta's proposals in 1995.

As noted in Chapter 3, Gas Supply Management, Delta uses the Canada Mountain Field as the entire source of supply for its Southern System. However, it should be noted that Delta retains a contract for 5,400 Mcf/day of delivery capacity from Columbia Gas Transmission at the Greenbriar Purchase Station, that could be used in place of, or as a supplement to delivery from Canada Mountain. That capacity is used only under extreme weather conditions, however and only under certain pipeline pressure conditions. The possibility of this capacity may provide additional gas supply management options for Delta that could be used towards serving new customers.

Additionally, because Delta uses a blended purchased-gas cost for all of its sales-service customers, and because of Delta's ability to purchase approximately half of those customers' supply requirements at a time of the year when natural gas is generally less expensive, the storage field has provided an opportunity to hedge a significant portion of those requirements since typical winter gas prices exceed summer gas prices.

As noted in Chapter 1, Gas Supply Planning, the capacity of the storage field indicated by engineering reports is in excess of the Southern System's winter requirements. Thus, Delta is continuing to consider the possibility of using some of that capacity to displace some of its requirements for pipeline delivery and storage services in other service areas.

In the course of required replacement of aging pipeline facilities, Delta is also upgrading its Southern System. Older 6-inch main lines are being replaced with higher-pressure 8-inch steel to enable higher-volume deliveries. With these enhanced capabilities, Delta has been able to provide increased supply security to its customers. Delta has also been able to transport gas to off-system markets in Tennessee, via a sales station near Jellico, Tennessee.

Delta's objectives for its northern service territories have also evolved somewhat as a result of the FERC's Order 636. Liberty noted above that Delta is considering whether some of the storage field's capacity might be used to displace some of the Company's requirements for pipeline services in other of its service areas. Other considerations include the appropriate amounts of supply capacity to those areas, and the costs of supply to those areas.

(2) Changes in Supply Activities

Delta's gas-supply activities for its northern systems are largely the same as they were before Order 636; pipeline supply has simply been replaced by supply from two marketing companies. Delta was assigned pipeline and storage capacity in the Order 636 implementation process, but the Company has contracted with marketers to manage that capacity. Thus, Delta's supply activities for those areas are largely the same as they were before Order 636.

Delta has conducted a competition to replace one of the two marketers, but the other one has been in place since Order 636 implementation. Delta's contracts for capacity on the Tennessee system have been adjusted upward since Order 636 was implemented, but the Company's Columbia contracts are the same. Hence, requirements estimation and the Gas Control function essentially are the same as they were prior to Order 636.

The Southern System is where gas-supply activities have changed. With the change in sourcing from local producers to an interstate supply source injected during the summer months into Delta's on-system storage, Delta has assumed responsibility for buying and injecting the gas, then withdrawing it in a way that ensures that its customers' needs are met on a seasonal and peak-day basis.

To date, Delta has not filled the field beyond the level required to serve its customers' normal winter-period needs. Facilities limitations have also limited Delta's discretion about when to fill the facility – injection has had to be more-or-less uniform over the injection season in order to achieve the desired fill level in the available time.

An easing of some of the indicated facilities limitations – completion of a 10-inch steel pipeline from Flat Lick to Greenbriar, and installation of additional compression at the storage field – will allow Canada Mountain to be developed "… to its full potential." As the storage field was proposed to and approved by the Commission, it was expected that it might eventually provide storage capacity in excess of the requirements of Delta's Southern System. Thus, when the facilities are complete, Delta may have opportunities to provide additional services to on-system and/or off-system customers.

(3) Capacity Cost Reduction

Delta has not reduced its capacity under contract for its northern systems. Its contract levels on Columbia are the same as they were at the time Order 636 was implemented, and its contracts on Tennessee are a little higher.

Delta's contracts on Columbia provide for one-part rates; thus, Delta contends that it is not paying for capacity on Columbia that it is not using. Similarly, Delta's contract quantities on Tennessee are sculpted, so that Delta pays for less capacity in the summer than in the winter. Again, because of the sculpting feature, Delta contends that it is not paying for capacity that is not being used to serve its customers.

Delta does not conduct any secondary-market activities (off-system sales and capacity-release transactions) involving its Columbia and Tennessee capacity. Rather, its capacity rights on those pipelines are assigned to its suppliers, Dynegy in the case of Columbia, and Woodward in the case of Tennessee. Those firms are free to use the capacity for secondary-market transactions, as long as they fulfill their supply obligations to Delta. Delta's customers participate in the proceeds of any off-system sales through the discounts that Delta receives on the gas that the two firms supply. Moreover, Delta receives 90 percent of any revenues derived from releases of the capacity to third parties. Over the past three years (1999-2001), this provision has provided no revenue from the Tennessee capacity, but about $90,000 from the Columbia capacity.

Delta's affiliates conduct activities that generate revenues for the utility. Delta Resources sells gas to about 40 customers on Delta's system, and pays transportation charges to Delta for moving gas to these customers. Delgasco buys gas at various places, both on and off of Delta's system, and transports the gas from receipt points on Delta's system to interconnections with other transmission facilities, to be sold to customers who are connected to those other facilities. (Delta refers to this service as "off-system transportation.") Other Kentucky gas producers also purchase transportation services on Delta's system to move gas to customers on other systems. These transportation services also generate revenues to Delta that offset Delta's capacity costs.

c. Conclusions

(1) Delta needs increased use of its system. *(Recommendation #1)*

Delta had a problem with gas supply for its Southern System that was going to be expensive to solve, no matter which solution was selected. Canada Mountain was the chosen solution, and the results of that investment are now in Delta's rates. Similarly, Delta has had some aging facilities that required considerable investment to bring them up to today's standards of integrity and functionality.

A result of all this investment is that Delta's total retail rates are usually the first or second highest of the five LDCs considered in this study, although at times Delta's retail rates are lower than some of the other LDCs, such as during the period of very high gas prices of 2000 - 2001. With the compounding of the rates effect caused by the high gas prices experienced during the winter of 2000/2001 Company personnel report at least anecdotal evidence of customer losses during that period.

Liberty's view is that Delta's system costs have increased to the point of negatively impacting the marketability of its services. Liberty observes that Delta's non-gas rate, which is where the costs of Canada Mountain and other facilities additions shows up, is fully three times as high as Western Kentucky Gas's (WKG). While WKG's business model sets a cost standard that is difficult to match, Delta's non-gas rates are substantially higher than those of the 4 other LDCs considered in this study.

The key to getting Delta's rates down is adding revenues from new services. Delta has been successful in adding revenues from off-system transportation services, but needs to continue its growth efforts.

(2) Utility system-supply issues must receive greater attention. *(Recommendation#2)*

As noted elsewhere in this report, Delta's Gas Supply personnel work not only for Delta, but also conduct supply operations for Delta's unregulated affiliates, Delta Resources and Delgasco. Liberty is concerned that the availability of full-requirements supply arrangements with Woodward and Dynegy implicitly encourages Delta's personnel to focus their attention on lines of business other than the utility's gas supply operations.

Delta's Columbia contracts will expire in 2008, providing the Company with an opportunity to seek better terms for its customers. The advent of Canada Mountain brings capabilities that may allow changes in Delta's requirements for storage and transportation services, as well. Use of the Canada Mountain Storage Facility to hedge Delta Natural's gas price needs careful study.

d. Recommendations

(1) Delta should focus on lowering the costs of its utility services and seeking additional revenues from its system where feasible. *(Conclusion #1)*

With the addition of Canada Mountain, the reinforcement of the pipelines in the Southern System, and the construction of the high-pressure pipeline from Canada Mountain to Greenbriar Purchase Station, Delta's system could eventually have capabilities available to provide additional services. What remains is to develop a comprehensive plan to take maximum advantage of all of these new facilities. Delta has reported that development of a marketing plan for those capabilities has been waiting for completion of these new facilities.

Delta personnel have mentioned several potential markets for these new capabilities. Chapters 1 and 2 above outlined marketing potentials and analysis requirements to assess them. Delta has pipeline and storage contracts that will expire in 2008. Liberty believes Delta does not carry a sense of urgency about developing a plan to optimize the use of the new facilities, including the necessary plan for marketing them.

Finding new markets for future capabilities is essential to future load growth for Delta. Delta is encouraged to continue to seek new business growth to utilize its system as much as possible.

In Chapter 3 of this report, Gas Supply Management, Liberty recommended that Delta report to the Commission at appropriate intervals on the progress of its testing program for Canada Mountain and the enhancements to Delta's Southern System facilities. Delta should also report to the Commission on its plans for marketing those capabilities.

(2) Delta should increase the priority of utility-service supply issues. *(Conclusion #2)*

As noted in the Conclusions relevant to this chapter, Delta has full-requirements supply arrangements for its Columbia- and Tennessee-supplied sub-systems. Liberty acknowledges that Delta's unregulated operations now account for perhaps 60 percent of Delta's business, and that those operations are where Delta is experiencing its best growth. Liberty also understands Delta's argument that the Company uses income from its unregulated operations to defer the need for rate increases for its regulated business.

Liberty believes that the advent of Delta's enhanced system capabilities, whatever those capabilities might eventually be, and the opportunity to revise its pipeline contracts, should be addressed. This should include:

- Development of a strategy for addressing pipeline and storage contracts that expire in the near future.
- Development of a strategy for optimal use of future Canada Mountain capacity.
- Development of a strategy for optimizing storage fill rates for Canada Mountain.
- Development of a strategy for addressing issues of priority in access to injection, withdrawal and transmission facilities.

- Development of a strategy for pursuit of additional markets for any of Delta's future enhanced capabilities.

In consideration of the above list of needed priorities for personnel dealing with utility service supply issues, Liberty cannot find evidence of specific performance objectives for Delta's regulated gas supply operations; this must change. Objectives must be set, and performance must be assessed, if regulated operations are to receive the attention that they deserve. Chapter 2, Organization, Staffing and Controls, contains a specific recommendation regarding needed changes in the performance management system.

7. Affiliate Relations

a. Scope

This chapter of Liberty's report addresses the affiliate relations aspects of Delta Natural Gas Company, Inc. (Delta) gas procurement practices:

- Structure of Affiliated Companies.
    - Placement and Structure of the Gas Procurement Function within the Affiliated Companies.
- Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.
    - Non-Gas Transactions with Affiliated Companies.
- Accounting and Reporting Issues for Affiliate Transactions
    - Cost Allocation Manual (CAM)
    - Allocation of Employee Time and Overheads
    - Other Accounting Issues
- Affiliate Transactions Relative to KRS 278
- Other Issues of Note

b. Background

(1) Structure of Affiliated Companies and Placement of Gas Procurement Function

Delta is a Kentucky corporation that operates under two segments, a regulated segment and an unregulated segment. Delta operates as a regulated gas distribution utility, and the company has three (3) wholly-owned subsidiaries in its unregulated segment: Enpro, Inc., Delta Resources, Inc., and Delgasco, Inc.

Enpro owns and operates production properties and undeveloped acreage; Delta Resources buys gas and resells it to industrial or other large customers on Delta's system; and Delgasco buys gas and resells it to Delta Resources and to customers not on Delta's system. The subsidiaries have no employees; all costs are allocated to the affiliates from Delta.

Gas procurement for both the utility and the gas marketing affiliates is done by the Gas Supply Department (*Gas Supply*). For utility system supply in the northern part of the system, Delta buys gas through two full requirements/asset management agreements, one supplying requirements off of Tennessee Gas Pipeline, and one supplying requirements off of Columbia Gas Transmission and Columbia Gulf Transmission pipelines. Delta holds its own firm transportation contracts and assigns them to the full requirements contracts; Delta does not hold any individual supply contracts for the northern part of the system. For the southern part of Delta's system, Gas Supply purchases summer spot gas for injection into the Canada Mountain storage field; storage withdrawal then supplies the vast majority of system requirements for that part of the system.

(2) Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

Beginning January 1, 2002, Delta no longer purchased gas from its affiliate companies. Although prior transactions were conducted at cost, the asymmetric pricing provisions of KRS 278.2207 convinced Delta that there was a potential risk of financial loss if market prices fell prior to a transfer between an affiliate and Delta. Currently, the only transactions between Delta and its gas marketing affiliates involve the transportation of gas at on-system and off-system tariff rates. Delta eliminated all other transactions with its affiliates.

(2a) Non-Gas Transactions with Affiliated Companies.

Delta employees provide all services for the affiliates, and employee costs and other overheads are allocated to the affiliates.

(3) Accounting and Reporting Issues for Affiliate Transactions

(3a) Cost Allocation Manual (KRS 278.2205)

Delta filed its Cost Allocation Manual (CAM) with the Commission on April 11, 2001 in accordance with the instructions of the statute. Costs incurred in providing all services to the affiliates are directly charged (employee time at burdened rate and direct purchases), when possible. Remaining costs are charged to the affiliates monthly based upon time studies of administrative personnel. The time studies, which are periodically updated, calculate the percentage of time that administrative employees spend on subsidiary activity. These percentages are applied to joint costs identified in certain accounts in the chart of accounts. The allocation percentages used in 2002 are based upon 2001 timesheet data, which is the first time the calculation had been reviewed in some time.

(3b) Allocation of Employee Time and Overheads

Interviewed employees keep a daily timesheet where they record how time is spent among the affiliates. The timesheets are turned in bi-monthly. Hours charged to affiliates are at a fully burdened rate. These timesheets from administrative/managerial personnel form the basis for the allocation percentage described in the CAM.

(3c) Other Accounting Issues

Gas invoices are approved and verified by Gas Supply. Volumes are checked against what has been scheduled and nominated, and indices or contract pricing is verified. Invoices from the full requirements suppliers are for system supply and are charged to Delta. If there are several packets of gas on a single invoice, they are listed separately and identified by package, volume and price. Any gas for storage would be charged to Delta, and other packets are allocated to the affiliates.

The same individual at Delta determines gas requirements, works with affiliate customers to procure gas supply, communicates and negotiates with suppliers for both utility and affiliate gas supply, and approves all invoices. There are no written procedures addressing how affiliate and utility purchases are made and subsequently entered into the accounting system. Backup (audit) detail for invoices is not attached to the invoice and the relevant computer files are deleted every few months.

There are no subaccounts within Delta's chart of accounts to reflect gas purchases from affiliates because there are no transactions. Gas purchases between affiliates are not tracked to subaccounts.

When there are transactions or other account entries between affiliates, the accounting computer system automatically creates both sides of the intercompany entry – a payable for one company and a receivable for another. These accounts are cleared twice a year.

The production affiliate (Enpro) produces gas that is sold at index to Delgasco. Transfer pricing from Delgasco to Delta Resources is at cost.

(4) Affiliate Transactions Relative to KRS 278

The person responsible at Delta was not appropriately aware of the requirements of KRS 278.2213 relating to a utility employee acting on behalf of an unregulated affiliate, having access to utility customer information, and promoting the affiliate's services – in this case, gas marketing services.

Management is aware of the asymmetric pricing requirements of KRS 278.2207, and Delta has changed its business practices to avoid any issues in that regard.

c. Conclusions

(1) The Delta gas procurement model does not involve affiliate issues and is a combination of asset management contracts for the northern part of the system and in-house procurement (summer spot supply into storage) for the southern part of the system.

Effective January 1, 2002, Delta no longer secures gas supply or related services from affiliates.

(2) Other than providing on and off-system transportation at tariff rates for affiliate company customers, Delta has eliminated all transactions with its affiliates.

On-system transportation rates are part of the Delta tariff, and affiliates pay the same rate any other gas marketer would pay for transportation customers. The off-system transportation tariff rate is also used by other transporters besides the Delta affiliate.

(3) Allocation of employee time and other costs between the utility and the affiliates is directly charged to the appropriate entity when possible; all remaining time/costs are allocated based upon historical time tracking of administrative personnel. The historical time tracking was reviewed for 2002 based upon 2001 timesheets; the previous review had been several years earlier. Individuals keep daily timesheets that are submitted bi-monthly. *(Recommendation #1)*

Accumulating all joint costs (that cannot be charged directly to an affiliate) and allocating them based solely upon historical records of administrative time is a very simple methodology. Other companies in the audit use a variety of cost allocation factors depending upon the nature of the joint cost.

(4) Gas Procurement and gas cost assignment practices are missing necessary controls.

a. **There is not sufficient separation of duties with respect to critical functions of determining gas requirements, working with affiliate customers to procure gas supply, communicating and negotiating with suppliers for both utility and affiliate gas supply, and approving invoices.**
b. **There are no written procedures addressing how affiliate and utility purchases are made and subsequently entered into the accounting system.**
c. **Backup (audit) detail for gas supply invoices does not accompany the invoice to accounting department.**

(Recommendation #2)

Delta has worked hard to maintain very lean staffing levels, and there is nothing inherently wrong with only one or a few employees being responsible for multiple areas within the LDC and the affiliates. However, it is possible to establish accounting controls to validate that any actions taken by a single employee are verifiable by someone else. Further, written procedures are especially important if the knowledge base tied to a very limited staff were to be lost, either permanently due to retirement or leaving, or temporarily due to illness or vacation.

(5) Intercompany accounts are cleared twice a year. *(Recommendation #3)*

Delta clears the intercompany accounts semi-annually in order to prevent paying taxes on intangible property. Otherwise, the company views its financials on a consolidated basis, and the subsidiaries have no cash accounts.

(6) Gas sales between the unregulated affiliates are appropriately at cost.

Transactions between affiliates are at cost to prevent the transfer of goods from creating a profit where none would otherwise exist. Transactions between the affiliates and the utility had been made at cost as well, but the asymmetric pricing provisions of the Kentucky statute raised concerns for Delta and the practice was completely halted beginning in 2002.

(7) The person responsible at Delta was not appropriately aware of the requirements of KRS 278.2213, addressing the sharing of customer information and the promotion of a non-regulated activity by the utility or an affiliate. *(Recommendation #4)*

The referenced statute states that if a utility receives a request for a recommendation from a customer seeking a specific service which is offered by the utility or its affiliate and the utility mentions itself or its affiliate when making the recommendation to the customer, that customer seeking a specific service shall be notified that competing suppliers of a nonregulated service exist.

d. Recommendations

(1) Delta should commit to evaluating, reviewing and updating procedures for allocating costs among the entities on a regular basis. *(Conclusion #3)*

Annual review of the timesheet allocation percentages is necessary to insure that changes in focus or effort are reflected in the allocation factors with no more than a one-year lag.

(2) Procedures should be revised to ensure necessary controls are in place, with focus on the following:

a. Revise responsibilities as much as possible (given staffing levels) when one individual performs multiple tasks for both regulated and unregulated entities.

b. Develop written procedures for gas procurement and invoice verification, emphasizing the necessary controls and cross-checks. The procedures should include the requirement that, at the time an order for gas supply is placed, appropriate records be created detailing the Delta company (utility or affiliate) for which the purchase is made, the date, volume and price. This should be retained as audit backup.

c. Sufficient backup detail should be included with the invoice, when it is forwarded to accounting, such that the transaction can be recreated and audited by another employee or third party. In addition to the records described in (2)b above, supplier/pipeline confirmations, customer order requests, or contract references might also be attached to the invoice as additional backup.

(Conclusion #4)

Procedural and accounting controls help ensure that as many people as possible have access to necessary information, which is especially important in a company with few employees.

(3) Intercompany accounts should be cleared monthly. *(Conclusion #5)*

Delta's accounting system appears to be sophisticated enough to clear accounts monthly so that each of the companies (utility and three subsidiaries) has a clear financial picture at any given time, even though Delta prefers to look at the consolidated results.

(4) Conduct a thorough internal training program on the requirements of KRS 278.2213 and the specific requirement that potential transportation customers be notified of alternate providers of gas marketing services, if any mention is made of the utility affiliate that also provides those services. Develop a list of alternative suppliers to provide to new or existing transportation customers. *(Conclusion #7)*

Again, having only a few employees serve many functions means that special care must be taken to follow the requirements of the statute. Marketing an affiliate using utility employees can be difficult if those employees do not fully understand the limitations detailed in the statute.

III. Company-by-Company Reports

A. Columbia Gas of Kentucky

1. Gas Supply Planning

a. Scope

This chapter of Liberty's report addresses the aspects of the Columbia Gas of Kentucky (*Columbia, CKY*) gas supply planning practices:

- Integration with Corporate Plans
- Risk Analysis
- Balancing Supply Options
- Supply Planning Flexibility
- Impact of New Markets
- Monitoring of Key Assumptions and Plan Implementation
- Peak Period Performance

b. Background

(1) Integration with Corporate Plans

CKY's gas supply operations are managed at the Columbus, Ohio office of the Energy Supply Services (ESS) Department of NiSource Inc., its parent company. ESS performs the gas supply related functions for the local gas distribution companies of NiSource. The office in Columbus manages utility gas supply operations in Kentucky, Virginia, Maryland, Ohio and Pennsylvania.

The centralization of gas supply planning efforts within ESS allows a high degree of efficiency and effectiveness in the planning process. Every year, CKY Finance personnel develop a five-year, normal weather monthly demand forecast, which is monitored monthly and updated periodically. For CKY as for the other four regulated utilities it plans for, ESS also generates a peak-day forecast report, using software internally developed named "Demand Forecaster." Upon upper management approval of the long-term demand forecast, ESS develops gas supply plans around these forecasts including colder-than-normal and warmer-than-normal seasonal (winter) design conditions. The forecasts also incorporate expected demand from customers of CKY's Customer CHOICE℠ program (*CHOICE®*), and the Director of Gas Supply Planning is responsible for the design and development of the operational side of the CHOICE program. [Note: Columbia may implement and publicly refer to its small volume transportation program as Customer CHOICE℠ and/or CHOICE®. Customer CHOICE℠ is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Kentucky, Inc. CHOICE® is a registered service mark of Columbia Gas of Ohio, Inc., and its use has also been licensed by Columbia gas of Kentucky, Inc.]

Day-to-day operations are managed within the ESS group under the direction of the three Directors. On a continual monthly basis, generally in the early second week of the month, ESS generates a short term price forecast that is subsequently used in the gas supply optimization model, which is updated with CHOICE® participation, capacity and supply availability. The optimization model is then run around the 20th of each month, and results are reviewed at a pre-bid meeting of the Directors. Once they're finalized, including optimization of storage utilization, the purchase requirements are passed on for the scheduling of purchases.

ESS staff also provides support to CKY in regulatory proceedings at the state and federal levels through expert witness activities, technical analyses, discussion with regulatory and collaborative groups, and by satisfying mandatory reporting requirements related to gas supply.

(2) Risk Analysis

As mentioned above, ESS prepares price forecasts and routinely incorporates them into their gas supply optimization model to generate the lowest cost gas supply solution given their monthly updated forecasts and storage inventories.

CKY's forecast considers residential, commercial and industrial customers along with unaccounted for gas, company use gas and wholesale gas. Residential and commercial use is estimated using forecasts of the number of customers and usage per customer in each of the six residential and six commercial groups, which have different usage per customer patterns, and multiplying by corresponding forecasts of usage per customer. Non-temperature sensitive base loads are estimated using end-use models, while econometric models for heat sensitive loads contain variables for real gas prices, seasons and trends with no weather terms since the usage per customer is weather adjusted prior to the econometric estimation. CKY forecasts are generated for two main demand areas, Lexington and Ashland. Industrial load forecasts are based on an econometric model including details such as state-level production index history by the twenty SIC codes comprising CKY's industrial demand and customer surveys of future demand. Supply and demand under the CHOICE® program is included in SENDOUT® separately and match daily and thus, is not a part of the gas supply optimization process for CKY sales customers.

ESS's Peak Day Forecast (PDF) document is generated each year for each of the five states for which the department conducts planning activities. The document includes both the forecast as well as an outline of the procedures for peak day sendout estimation. In addition to forecasts of design peak day demand, the PDF also provides estimates for each month's daily maximum and minimum demands. These demands are based on local weather and a 10% risk probability which happens to correspond to an approximately 10% higher level of HDDs on an annual basis. Currently, assuming the CHOICE® program did not exist or mandatory assignment under the CHOICE® Program, a design day occurrence would require CKY to purchase spot gas equaling approximately 5% of the peak day design. Under optional capacity assignment for CHOICE® CKY is able to eliminate this spot purchase requirement through the retention of capacity rejected by CHOICE® marketers.

CKY does not have any formal policies on maximum levels of reliance on any particular supplier or individual vendors. CKY contends that the company's service territory provides limited options via alternate suppliers and pipelines to serve its customers, and that firm storage service (FSS) provided on the pipeline is key in balancing demand at CKY's 110 delivery points, and hence is an additional factor limiting options.

(3) Balancing Supply Options

Columbia has the necessary procedures in place to evaluate and acquire gas supplier alternatives. The company makes extensive use of its gas supply optimization model to evaluate both short-term and long-term gas supply planning decisions. The assessment of future market conditions is a part of the forecast through the economic assumptions and variable inclusions. The optimal contract and supply mix, and the mix between long-term and spot purchases is considered and calculated based on gas prices and storage inventories using the optimization model. This ensures a least-cost solution and the optimal use of resources for a given demand forecast and associated cost estimates for all gas supply resources such as suppliers, pipelines, storage and peaking resources. This is currently one of the best methods to perform long term gas supply planning.

Many Columbia pipeline contracts are due for renewal in 2004, which will require either the extension of existing contracts or replacement with new contracts. Columbia claims to have very limited lower cost options with regards to pipeline and storage capacity. This indicates that renewal of a significant portion of the contracts with its affiliate pipeline company is likely. The company has historically analyzed alternate resources to include or exchange in the portfolio. These analyses have not yielded opportunities to replace capacity within its current portfolio due to unfavorable economics and/or long-term contractual commitments. The Company has initiated specific studies to determine the least cost capacity options it can pursue as these long-term contracts expire.

Columbia does not have a specific process designed to ensure a diverse mix of suppliers; however, supply contracts with troubled energy companies are not a part of the core supply group and hence do not cause reliability issues. Columbia does have the extra consideration of supply that needs to be provided for CHOICE® customers, and risks in that domain have not been formally assessed. However, Columbia, recognizing its role as Supplier of Last Resort under its CHOICE® Program, releases capacity to CHOICE® marketers on a recallable basis enabling it to rapidly recall any released capacity on short notice should a marketer unexpectedly exit the program. Furthermore, under optional assignment Columbia retains sufficient capacity to cover 20% of the peak day requirements of customers participating in CHOICE® in the event of a supply failure by one of the CHOICE® marketers. Historically, CKY has not had any problems regarding their own firm gas suppliers, and problems with only a couple of the third party suppliers (as described elsewhere in the document) in the CHOICE® program. There is a separate capacity management system for CHOICE® balancing that is used as a part of the gas supply process.

Columbia has filed a request with the Commission to allow mandatory assignment of pipeline and storage capacity for CHOICE® customers. This will formally define the allotment of resource availability and hence the costs associated with serving sales customers. Columbia intends to keep those capacities available to ensure deliverability to CHOICE® customers in the event of failure by third parties.

Columbia's gas supply optimization runs contain three weather patterns; one for warm weather at 59 peak day HDD and 4254 annual HDD, one for normal weather at 66 peak day HDD and 4686 annual HDD and one for cold weather at 70 peak day HDD and 5082 annual HDD. These figures are well within the bounds indicated by historical weather.

(4) Supply Planning Flexibility

Columbia's forecasting and gas supply planning procedures are complete. They incorporate economic variables and consider gas price forecasts. Changes are made as necessary to accommodate changing gas markets to ensure the best mix of resources and provision of the lowest cost gas to CKY customers.

CKY's decision to seek mandatory assignment under the CHOICE® program minimizes risks of defaults from third party suppliers, but does not allow for third parties to achieve additional savings by providing gas deliveries to CKY city-gates.

Short-term gas supply decisions are made continuously by the Directors of Gas Operations and Gas Procurement and their staffs. Managers from the sections meet daily during the winter season to evaluate CKY's storage position and review the Gas Operations Outlook ("GOO"). The GOO develops a five-day supply and demand balance that includes a demand and supply forecast for CKY's traditional transportation customers, marketers participating in the CHOICE® program, CKY's own flowing supplies and the resulting impacts on CKY's storage.

As mentioned above, Columbia does seek supplier diversity but is bound by pipeline and storage agreements that don't expire until 2004. Columbia has historically reviewed alternatives within its gas supply resource portfolio, but indicates that there are limited lower cost options for such services for most of its service area.

As indicated above, supply contract terms are not affecting planning flexibility; there is sufficient diversity and contracts with suppliers that have recently been financially troubled are not considered in the firm portfolio. Risk of third party supplies remains a risk but is not affecting supply planning flexibility since Columbia considers parts of resources dedicated for the CHOICE® program and has requested mandatory assignment of the appropriate portions of its gas portfolio contracts to the CHOICE® program providers. However, the CHOICE® program does take away incentives for CKY to seek new connections to alternate pipelines as the assignment of the cost of such investments would need to be made by funding such investments from the sales customer base.

Columbia's current contracts with its affiliate transmission companies provide Columbia with the necessary planning flexibility via open balancing agreements at various city-gate delivery points; this is one of the features that Columbia relies on to efficiently manage its system and justify the expected extension of its contracts.

(5) Impact of New Markets

Columbia's market area is not exhibiting significant growth that would warrant additional analysis in gas supply planning. The current forecast for demand under the CHOICE® program is a steady portion of total sales. Significant changes to the CHOICE® program, however, may affect the assignment of capacity to the marketers and require changes in contracts with gas suppliers, but will not affect contracts for pipelines and storage services, especially if mandatory assignment is granted by the Commission. If there are new markets to be considered in the forecast, CKY's Lexington office provides ESS with information on the extent of the impact.

(6) Monitoring of Key Assumptions and Plan Implementation

Columbia monitors key assumptions during the forecasting process; directors of ESS constantly reevaluate forecast assumptions during periodic meetings. However the company does not prepare a document to compare forecasted gas supply to actual gas supply. Annually Columbia performs a winter season review following each winter that compares weather and demand to normal conditions and reviews storage activity and operational actions over that period.

(7) Peak Period Performance

During the period 2000-01, weather conditions did not exceed design day conditions. Material provided to Liberty indicates that firm demand is highly correlated with degree-days, and that the highest daily firm demand occurred on a 7-degree day (i.e. 58 HDD). While total HDD for years 2000 and 2001 were less than 4800, which was below the 5082 HDD level planned for in the design winter gas supply optimization model, the month of December 2000 was significantly colder than the seasonal design incorporated in Columbia's planning process (988 HDD for design December vs. 1240 HDD for December 2000.) and happened to coincide with the gas price spike in the second half of the month.

Columbia uses a firm storage service (FSS) contract to provide peak-day deliverability. In order to allow for maximum withdrawal rates during a peak demand day, ESS constantly monitors the level of storage inventory to ensure that it does not prematurely fall below ratchet levels. The peak day forecast document outlines assumptions regarding the occurrence of a peak day, with a 10% probability assigned to a latest cold day occurring around the first week of February. Therefore, Columbia ensures that maximum and/or needed withdrawal rates will be possible from storage on its design seasonal and monthly peak days.

c. Conclusions

(1) Columbia has commendable gas supply forecasting procedures.

Columbia's gas supply forecasting procedures are very thorough. Due to Columbia's centralized operations in Columbus, Ohio, steps involved in the gas supply forecasting process are done efficiently for many locales.

Columbia's weather analysis in the Peak Day Forecast Report is one of the most thorough analyses provided by the utilities in this audit. As mentioned above, Columbia evaluates its gas supply plan using three different weather patterns; one for warm weather, one for normal weather and one for cold weather with approximately 10% variation in annual HDD.

These figures are well within the bounds indicated by historical weather, and even may be lower than necessary to ensure adequate deliverability in extreme cold conditions, requiring spot gas purchases in extreme cold weather.

(2) Columbia's analysis of economic gas supply portfolio alternatives is primarily limited to options provided by its affiliates, Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company. *(Recommendation #1)*

Columbia has the necessary procedures and models in place to evaluate and acquire gas supplier alternatives. Several contracts are due for renewal in 2004, which will require either the extension of existing contracts or replacement with new contracts. Columbia claims to have very limited lower cost options with regards to pipeline and storage capacity. As mentioned earlier, this indicates that renewal of a significant portion of the contracts with its affiliate pipeline companies is likely.

Columbia's current contracts with its affiliate transmission company provide Columbia with desired flexibility and deliverability at each city-gate delivery point; this is a justification for Columbia to extend these contracts. However, only a cost-benefit analysis using a gas supply optimization model (such as NEA SENDOUT®) can determine the tradeoff between the difference in flexibility and the difference in costs between existing and potential replacement pipeline or storage contracts in the context of Columbia's existing gas supply portfolio and expected firm demand. The Company has historically analyzed alternate resources to include or exchange in the portfolio. These analyses have not yielded opportunities to replace capacity within its current portfolio due to unfavorable economics and/or long-term contractual commitments to date. The Company has initiated specific studies to determine the least cost capacity it can pursue as these long-term contracts expire.

(3) Columbia's gas supply portfolio is properly designed and merits the analysis of potential cost tradeoffs in the event of design day occurrences. *(Recommendation #2)*

Using CKY's gas supply portfolio (not considering capacity assigned to CHOICE® marketers) and base/use factors for sales customers obtained from the SENDOUT® run, combined with weather in the Test Case and maximum January HDD and maximum annual HDD, Liberty performed its ROGM analysis for CKY. (ROGM is Liberty's gas supply optimization and simulation tool for integrated least cost planning, demand-side management program evaluation and marginal cost analysis). Liberty's ROGM results indicate that CKY's current pipeline and storage portfolio is barely capable of handling extreme weather conditions.

The ESS Director of Gas Supply Planning indicated that additional peak day purchases of up to 5% may be required on the spot market. The Company has in the past conducted evaluations of the cost tradeoff between spot purchase requirements with price and quantity considerations compared with the price of additional storage or peaking services. Given changes in the marketplace relative to gas prices, these studies are likely outdated and should be reviewed and updated.

(4) Columbia's operational planning meets the same high standard as its annual planning.

As noted above, Columbia's gas supply planning procedures are very thorough, and well integrated with corporate planning. Due to Columbia's centralized operations in Columbus, Ohio, many steps involved in the gas supply planning process are done efficiently for many locales. Columbia's Peak Day Forecast report contains a comprehensive analysis on the distribution of weather and peak day sendout for each rate class. All risks are thoroughly analyzed, with scheduled meetings involving local affiliate personnel for providing input into the process about local changes, and fine-tuning the planning process as necessary.

Columbia's dispatch, or operational planning, is based on forecasts that meet the same high standard. Columbia's employment of a gas supply optimization model is sound. It incorporates both short term and long term forecasting provisions, along with continuous monitoring of storage inventory levels to avoid ratchets until properly calculated peak day occurrence probabilities have been exceeded. It also incorporates the balancing of gas purchases within the process, considering that gas price forecasts comprise a comprehensive methodology for gas supply planning.

d. Recommendations

(1) Columbia should expand its efforts to develop more competitive gas-supply alternatives, and seek to reduce its capacity costs. *(Conclusion #2)*

Columbia should complete ongoing studies of alternate pipeline and storage resources to supplant its portfolio. Given its current use of a gas supply optimization tool such as SENDOUT®, it is possible to evaluate many scenarios efficiently by adding terms of proposed contracts to the model and observing displacements that the model suggests. Columbia must focus on ways to reduce its capacity costs given upcoming contract retirements, and then proceed to adjust its contracts accordingly.

(2) Columbia should augment its peak day forecast to incorporate potential cost tradeoffs regarding the selection of peak day criteria. *(Conclusion #3)*

CKY indicated that, under current planning tolerances, the occurrence of extreme cold conditions would require additional spot purchases. Columbia's peak day forecasting report considers a peak day planning criteria based on a 10% occurrence, in contrast to ULH&P's assumption of 3%. In other words, Columbia's system would be able to satisfy demand 90% of the time, while ULH&P would be able to satisfy demand 97% of the time on a peak day.

Liberty believes that an updated evaluation of cost tradeoffs regarding spot purchase prices and quantity requirements vs. the cost of acquiring additional storage or peak shaving capacity would enable a planning level with potentially lower costs to CKY customers.

2. Organization, Staffing and Controls

a. Scope

This chapter of Liberty's report addresses the aspects of the Columbia Gas of Kentucky, Inc. (*Columbia or CKY*) management and operations that relate to its overall organization, staffing and controls:

- Organizational Structure.
- Staffing.
- Approval Authorities.
- Work Process Definition and Control.
- Documentation Requirements.
- Auditing.

b. Background

(1) Organizational Structure & Staffing

Natural gas supply planning, procurement and gas operations management activities for Columbia are handled by the Energy Supply Services Department (*ESS*) within the NiSource Corporate Services Company. ESS performs the gas supply related functions for the local gas distribution companies of NiSource Inc. ESS has offices in Indiana, Ohio, and Massachusetts. That portion of the ESS organization located in Columbus, Ohio provides the gas supply services to Columbia Gas of Kentucky, as well as to Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

The services provided to CKY by ESS are divided by function under three Directors, the Director of Gas Operations, the Director of Gas Procurement and Transportation, and the Director of Gas Supply Planning. For purely administrative reasons, the Director of Gas Procurement and Transportation also serves as the Director of Gas Management Services, a position to which all three Directors report, on paper only. This arrangement facilitates communication with the Vice President, Energy Supply Services, and does not reflect that either position is open or needs to be filled by Columbia.

The ESS Department is lead by the Vice President of Energy Supply Services, who in turn reports to the President of Energy Supply Services, located in the corporate offices in Indiana.

Gas Operations

The Gas Operations function supports the provision of safe, reliable and economic gas delivery for Columbia Gas of Kentucky's customers. Performing the Gas Operations function requires the maintenance of a Gas Control Center that is staffed 7 days a week / 24 hours per day, which has the ability to monitor and control the flow of gas at critical points on CKY's system on a continuous basis.

The Gas Operations function annually determines the future estimated demand of CKY customers under "design day" conditions to ensure that CKY will have sufficient supply/capacity assets to fulfill its utility obligation in future years. Gas Operations also determines on an ongoing basis the daily gas demand to be served by CKY so that sales customer's demand can be met in a reliable manner and so that the Company is able to appropriately manage its gas balancing services to transportation customers, as supplies and weather conditions change.

Gas Procurement and Transportation Services

The Gas Procurement service involves the purchase and sale of gas, including contract negotiation, the scheduling of gas supply on the interstate pipelines, and the release of interstate pipeline capacity. The function also performs the review and approval for payment of all pipeline and supplier invoices and the generation of invoices related to sales made off system by ESS.

The Transportation Service performed by ESS involves the management of the daily gas nomination process using ESS's GAIN+ Internet based site. ESS supports transportation services by assisting CKY with the education of marketers and transportation customers, and by supporting various CKY transportation initiatives involving transportation customers and services.

Gas Supply Planning

Supply Planning works to develop and maintain the optimum portfolio of pipeline capacity, storage and peaking supplies appropriate to meet the near term and the longer term seasonal and design day needs of CKY.

Planning determines the annual usage of capacity assets held by CKY and focuses on lower gas cost solutions, the recovery of gas costs through the regulatory process and improved competitiveness and improved reliability of CKY's merchant and transportation services. To accomplish this, Planning prepares technical studies, long-term strategic plans for gas supply portfolios and solutions to facility requirements, and makes use of state of the art economic optimization models. Included in the Planning function's responsibilities is the design and development of the operational side of Customer Choice^{SM} programs.

The Planning function provides support to CKY in regulatory proceedings at the state and federal levels through expert witness activities, technical analyses, discussion with regulatory and collaborative groups, and by satisfying mandatory reporting requirements related to gas supply.

Performance Measurement

There are two components to the performance measurement system used within ESS to determine a person's salary adjustments and bonus. The first part is a merit component, and is usually about 3% to 4% of a person's salary. Since this component is tied to corporate performance, the adjustment could be zero if corporate performance is poor. Employees are measured on goals set at the beginning of the evaluation year, with both the manager and the employee having input into the goals. Overall, the system is driven by give and take between the manager and the employee, and self-assessment, as well as managerial assessment is part of the process.

The current system at ESS is evolving because of the new relationship with NiSource. It is unclear that some of the valuable features of the program will be retained. Under the old Columbia structure, Directors helped develop more specific goals that were documented as part of the performance measurement process, but that is not currently occurring – at least not on paper. Under the old Columbia system, typical goals might have been to have no repricing issues, to minimize penalties, or to meet established financial goals. Under the current system, Directors have a verbal understanding with the Vice President on these types of items, but they are not documented.

The second part of the system relates to bonus potential, and is a system used throughout NiSource. Earnings per share goals make up 50% of the bonus potential for an employee, while the individual and departmental goals set forth at the beginning of the period, as described above, make up the other 50% of the potential. However, for any payout to occur, the earnings per share goals must first be achieved. Considerable time is now being spent on this component of the performance measurement system in order to minimize the risk of losing people. The objective of the program is to create incentives for every member of the team, and to give each employee the opportunity to receive compensation that places him/her in a competitive position with respect to the job market.

Inherent in each of the components of the evaluation system is whether or not employees hit the targets related to planning, procurement and management of the gas supply function. These measures relate to deadlines, quantities and costs to be met, as mutually agreed to between managers and employees.

During each annual evaluation period, there are two meetings between managers and employees, one mid-year, and a comprehensive evaluation at the end of the year.

Columbia does use job descriptions as a guide for performance measurement, but the main drivers are the goal setting targets between managers and employees.

Training

There is no formal training program, or training manual, for employees in ESS in general, but significant attention is paid to training. New employees are sent to orientation sessions, as well as to gas industry seminars and training in Houston. In the back office, Columbia has a program of switching responsibilities on a regular basis so that everyone knows how to do the other person's job. In Gas Control a training program and manual exist with documentation and testing plans being developed to ensure compliance with the Federal Department of Transportation's "Operator Qualification" requirements

The Director of Gas Management Services feels that if he were to suddenly leave the Company, his operation would continue to function without missing a beat, and that there are several people who could step into his shoes. He feels that he is at an advantage because his staff has been with him for at least 10 years; they know how the business functions because he is not a micro-manager, and he gives his people free rein to solve problems themselves, to run the business themselves. He makes a point of delegating considerable responsibility.

Job Descriptions

Job descriptions for employees involved in gas planning, procurement and operations functions are not current. Since the old job descriptions were written, jobs have changed, and jobs have been merged such that many of the descriptions are no longer relevant. Management of ESS is aware that work needs to be done in this area and efforts are underway to update them before the end of this year.

(2) Approval Authorities

Approval of activities within ESS is controlled by a formal decision matrix, or a list of authorities. For example, the Traders have the ability to sign individual Transaction Confirmations for monthly and daily spot purchases that they make, but most other contracts, including base purchase contract to which Transaction Confirmations are attached, are first approved within ESS, and then sent on to the specific LDC for signature by the President or General Counsel & Secretary of that LDC. All of the commodity, capacity and transportation agreements are specific to each Columbia LDC.

(3) Work Process Definition and Control

The operations of the gas planning, procurement and operations functions are guided by, formalized, written policies and procedures that are current. The procedures are extensive, and part of what is called the Gas Operations Guide. The Director, Procurement & Transportation is confident that employees of the Department understand and use these procedures because they are an integral part of the daily gas management process. If the procedures were not being followed, he feels he would know immediately because he would see that the daily gas management activities were not functioning properly. Columbia has indicated that many of their newer procedures had the benefit of being documented through such vehicles as the Choice[R] tariff.

Columbia has an unusually comprehensive and complete set of procedures dealing with Risk Management, entitled "NiSource Risk Management Policy" dated August 2001. To ensure that employees understand these procedures, each employee is required to sign a statement indicating that they have read and understand these procedures.

(4) Documentation Requirements

Documentation of gas procurement and supply management activities within Energy Supply Services is satisfactory.

Communication within ESS is active, and facilitated not only by frequent meetings, but also by the physical layout of the workspace as well as numerous reports generated on a routine basis. The working environment is an open one, with no real separate offices for either employees or Directors. Low-level partitions do separate the desks of employees. Through such an arrangement, all employees have the sense that they work as a team, and communicate with each other as needed on important gas procurement and management issues.

Because of this open environment, the Director, Gas Management Services has no regular staff meetings; this is by design. He feels that the open workspace eliminates the need for such staff meetings. He feels that his organization demonstrates positive morale, good team spirit, and sound communications.

On a daily basis, there are "GOO," or Gas Operations Outlook meetings held in the morning between operations and purchasing personnel. These meetings look at gas operations for the day, and for the next four days. They review temperature forecasts, expectation of supply and demand based on weather, and whether or not storage injection or withdrawal will be required to stay within storage contract parameters.

The purchasing group meets with the planning group no less than monthly. Formerly, this was called a pre-bid meeting, but now it is referred to as the monthly operations meeting. The meeting is usually held on about the 23rd or 24th of the month. It includes price forecasting, discussion of issues before them, such as storage versus pipeline usage, and people attending bring their reports and worksheets to contribute to the meeting. Sendout model runs are used as the basis for discussion, and the results of this meeting feed into the gas nominations and contracts that the group feels will be necessary to have in place for the next month.

Weekly, upper management is kept advised of activities in the gas operations area through a staff meeting with the Vice President of Energy Supply Services in the corporate offices in Indiana. The meeting is held by phone conference call, and lasts from 1 to 2 hours. Attending are the

Directors of Gas Operations, Gas Procurement and Transportation, and Supply Planning. The Vice President does try to meet in Columbus frequently – at least weekly, but he is not always able to do this. These meetings are only one of the ways that upper management receives information on the activities related to gas planning, procurement and management. In addition, a significant number of hard copy reports, and email reports are transmitted on a regular basis.

The Directors of Gas Operations, Gas Procurement and Transportation and Supply Planning maintain an open line of communication with Columbia's Executive Vice President and Chief Operating Officer in Lexington as well as other operations, sales and marketing, communications and regulatory personnel. As the need arises, any one of these personnel may contact any one of the directors in Columbus and vice-a-versa. Formal meetings are held in the fall in preparation for the winter heating season.

Columbia does have a comprehensive Strategic Plan, dated 1998 – 2002. This was a long term, 5-year plan that was prepared on a regular basis under Columbia. The value of the plan was that it accomplished two important things: 1) It was a document to tie a long range strategy with policies and procedures necessary to develop a good procurement plan; and 2) It provided senior management with a forward looking view as to the adequacy of the match between supply and requirements. This also gave senior management a view of the overall planning process, and the tools that would be required to manage it successfully. The purpose of this plan was not to produce data, but to establish focus and a process for better gas management. The last plan prepared in 1998 was an especially important one because it was driven by the new Choice[R] program. The more formal written part of this process was discontinued for CKY after this plan was developed in an effort to save the associated cost.

(5) Auditing

ESS has been audited annually by internal auditors over the last five years. From time to time, some discrepancies have been noted and corrected. The last audit conducted in early 2002 concluded that internal controls are effective in mitigating the important business risks inherent in the gas supply process.

c. Conclusions

(1) Columbia's sound Long Term Strategic Planning process is in danger of being compromised. (*Recommendation #1*)

Columbia does have a comprehensive Strategic Plan, prepared in early 1998 and dated 1998 – 2002. This was a long term, 5-year plan that was prepared on a regular basis under Columbia. Since that time the formal written portion of this planning process is not anticipated to continue in an effort to save costs.

(2) Columbia's performance measurement system for individuals may change, with the associated loss of some of its valuable features. (*Recommendation #2*)

The current system at ESS is evolving because of the new relationship with NiSource, and early indications are that some of the valuable features of the program for individual performance measurement will be dropped. Under the old Columbia structure, Directors helped develop more specific goals that were documented as part of the performance measurement process, but now-they are not – at least not on paper. Typical goals under the old Columbia system had been to have no repricing issues, to minimize penalties, or to meet established financial goals. Under the current NiSource system, Directors have a verbal understanding with the Vice President on these types of items, but they are not documented.

(3) Job Descriptions for positions in the Energy Supply Services Group are not current and do not effectively describe the positions to which they apply. (*Recommendation #3*)

Job descriptions for employees involved in gas planning, procurement and management functions are not current. Since the old job descriptions were written, jobs have changed, and jobs have been merged such that many of the descriptions are no longer relevant.

(4) Columbia has done a good job of documenting the policies and procedures related to procurement and management of natural gas supplies.

The operations of ESS are guided by formalized, written policies and procedures that are current. Procedures used by the Department are lengthy and detailed, and are kept up to date as necessary. Columbia's procedures for Risk Management are especially noteworthy.

(5) Columbia has an effective internal auditing program.

Columbia has recognized that regular internal auditing is important both as a management control tool, and as a vehicle to indicate areas where specific gas planning, procurement and management functions can be improved.

ESS has been audited annually by internal auditors over the last five years, and while some discrepancies have been found, they have been corrected in a timely fashion. The most recent audit found that internal controls are effective in mitigating the important business risks inherent in the gas supply process.

d. Recommendations

(1) Continue the Long Term Strategic Planning process by completing another plan similar to the one dated 1998 - 2002. (*Conclusion #1*)

Utilities throughout the country have determined that regular preparation of strategic plans for the natural gas business are a sound way in which to effectively address the changing environment of the business and to continually keep senior management abreast of the issues facing their operations.

Preparation of a new strategic plan at Columbia is especially important now because of the significant changes taking place in the Columbia business environment. These changes include overall strategic considerations related to the merger with NiSource, shifts in use and value of the CHOICE[R] Program, and new trends in the electric power generation market that are now impacting the natural gas business.

Therefore, as soon as possible, Columbia should prepare a Long Term Strategic Plan similar to the one last prepared and dated 1998 – 2002.

(2) Maintain the formal component of the performance measurement system that includes documentation of goals and objectives for employees. (*Conclusion #2*)

Written goals and objectives that form the base for a performance management system are important to the success of an effective system. Committing goals and objectives to writing is important for a number of reasons:

- The process of documenting goals and objectives creates the most effective means of identifying meaningful goals and objectives and subsequently prioritizing them.
- Written goals and objectives form a lasting contract between the employee and his supervisor.
- Written goals and objectives provide a frame of reference for the employee so that the targets for the year are always available for reference.
- Written goals and objectives provide a solid basis for performance evaluation at the end of the year by the supervisor who can use these documented goals and objectives for comparison with actual employee performance.
- Goals and objectives that are only verbally discussed can be forgotten, changed, or misinterpreted.

Therefore, Columbia should continue the past practice of ensuring that written goals and objectives are part of the performance measurement system for individuals.

(3) Revise and update job descriptions for the Energy Supply Services Group to appropriately reflect the current staffing, and the current responsibilities of this staff. (*Conclusion #3*)

ESS should begin a program to update all job descriptions. This program should ensure that all job descriptions are reviewed to determine that they accurately describe the current responsibilities and activities of the positions for which they were written, and that job descriptions for positions that no longer exist are removed from the files of active job descriptions.

3. Gas Supply Management

a. Scope

This chapter of Liberty's report addresses CKY's gas supply management. Topics addressed include the following:

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Renegotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management

b. Background

(1) Existing Gas Supply Portfolio

Prior to the FERC's Order 636, CKY, and the other Columbia distribution companies, were full-requirements customers of Columbia Gas Transmission. Columbia Transmission had regional transmission and storage facilities – mostly downstream of CKY – and supply relationships with upstream pipelines, including its upstream affiliate, Columbia Gulf Transmission.

In the Order 636 implementation process, not only was Columbia Transmission's gas supply unbundled from its transmission and storage capacity, but its customers were assigned shares of its upstream capacity, as well. Thus, CKY came out of the process with contracts for transmission and storage capacity on Columbia Transmission, but it also has transmission capacity on Columbia Gulf and Tennessee Gas Pipeline.

CKY's contracts with Columbia Transmission and Columbia Gulf expire at the end of October 2004. CKY's contract on Tennessee has already expired, but it was renewed because that capacity is required in order for CKY to serve part of its service area near Ashland, Kentucky. CKY's capacity contracts are summarized in Table 3.1 on the next page.

CKY also serves 2,500 to 3,000 customers in eastern Kentucky from affiliate Columbia Natural Resources's (CNR's) gathering system. Customers include both "farm taps", where individual customers are served from gathering lines, and city gates, where facilities owned by CKY serve groups of customers, and those facilities are supplied by CNR. CKY's CNR contract also expires on October 31, 2004, but CKY advises that there is no real alternative to this service.

Table 3.1 Transportation and Storage Volumes

Columbia Gas		**Columbia Gulf**		**Tennessee**		**Texas Eastern**	
Rate	*Volume*	*Rate*	*Volume*	*Rate*	*Volume*	*Rate*	*Volume*
FTS	41,566	FTS	28,991	FT-A	21,506	IT	100,000
IGS	40,000	ITS	76,424	IT	25,000		
ITS	40,000						
SST - Oct-Mar	190,880						
SST - Apr-Sep	95,440						
FSS - MDQ	190,880						
FSS - SCQ	9,557,942						
SIT - MBQ	350,000						
ISS - ISQ	104,166						

Note: all volumes Dth/day except SCQ, MCPQ, MBQ

As noted in Chapter 2, Organization, Staffing and Controls, Columbia's Energy Supply Services Group (ESS) conducts gas-supply operations for all five Columbia distribution companies (CDCs) on a shared-services basis from its offices in Columbus, Ohio. ESS conducts a gas-supply solicitation process every year for all five of the CDCs. As a result of that process, contracts are concluded with a number of suppliers. When the location of the gas purchase (i.e. the receipt points on the interstate pipelines) are in common, then quantities agreed with each supplier are broken into specific amounts for each of the five CDCs, and contracts are concluded on behalf of each of the five. For both capacity and commodity, each of the five CDCs has its own contracts.

CKY's term contracts for gas supply are listed below in Table 3.2. As shown in the table, supply contracts range from three months (December – February) to multiple years. The most recent solicitation did not yield improved terms for contracts of more than one year's duration, so the longest new contract was for one year.

Table 3.2 Gas Supply Contracts

Contracts	**Term**	**Volume**		**Type**
Multiple	12/1 – 2/28	168,500 MMBtu	MDQ	Firm
Multiple	11/1 – 3/31	327,700 MMBtu	MDQ	Firm
Multiple	Annual and 12/1 – 3/31	0 – 40,000 MMBtu	MDQ	Swing
Multiple	Annual +			Local Production

In addition to these term contracts, ESS buys a significant amount of spot-market gas. Spot gas can be 30 to 40 percent of annual supply, depending on the weather. While most spot purchases occur during the summer, to fill storage, some can be in the winter. During the winter of '00/'01, for example, ESS made significant spot purchases because the early very cold weather (November and December, 2000) depleted storage volumes to a level below ESS's targets.

(2) Supplier Identification and Qualification

ESS is interested in supplier diversity. Its request-for-proposal (RFP) materials for its annual solicitation for term gas were sent to 24 suppliers in 2000, and to 22 suppliers in 2001. In years past, the CDCs had a formal policy regarding supplier diversity, but it has not been updated. ESS tries to maintain supply relationships with at least 10 suppliers all the time, and it tries not to exceed 15 percent of its requirements with any one supplier. These rules are no longer a formal policy, but they continue to be an informal objective.

The limit on supplier diversification is that the CDCs need to be dealing with substantial entities, who are willing to work with them all of the time. ESS has a variety of requirements for supply, including considerable spot-market supplies, and, on any given day, ESS often has gas that it needs to place through an off-system sale. With a relatively small staff, ESS simply does not have the time to go to a lot of potential deal partners with each requirement; consequently, it ends up doing business with firms that can respond quickly to its needs. ESS is in contact with a substantial number of market participants in the course of administering off-system sales and capacity releases as part of Columbia's Customer CHOICE programs (which operate in all five of the CDCs), as well as buying gas for all five. Suppliers who are responsive and interested are welcomed to ESS's bidders lists.

(3) Identification of Acquisition Needs

As reported in Chapter 1, Gas Supply Planning, ESS has very sophisticated supply-planning capabilities, which are used for estimating both short-term and longer-term requirements. Columbia's capacity contracts are fixed until 2004, so the acquisition process in the near term focuses on gas supply.

ESS contracts for much of its supply through its annual request-for-proposals (RFP) process. Initiated in the spring of each year, the process involves sending RFPs to as many qualified suppliers as possible, carefully analyzing the responses, and entering into contracts with proposers who submit attractive proposals, and who pass successfully through ESS's supplier-qualification process. The process takes considerable time, but is concluded prior to the beginning of each year's heating season.

Because of the tight fit between CKY's capacity contracts and its winter-period requirements for gas supply, ESS's first job is to fill storage. This task is accomplished with some term purchases, but mostly with purchases of spot-market gas. Purchases for, and injections into, storage have to be more-or-less uniform over the storage injection season because of operating limits on storage injection imposed by the storage operator, Columbia Gas Transmission.

Once into the heating season, ESS must intensify its focus on operating its storage and transmission capacity on Columbia Gas Transmission. As opposed to most interstate pipeline systems, that have most of their gas sources at one end of the pipeline and most of their gas markets at the other end, the Columbia Transmission system has gas coming into the system all over it, and gas leaving the system in many places, as well. Gas comes into the pipeline system from storage facilities in four States, from at least six upstream pipelines, and from Appalachian production, which enters its system at hundreds of locations. Gas goes out of the pipeline system into markets year-round; during the heating season, it may also go into storage on a warm day, or when cold weather has depleted storage levels to below the target for a particular point in the season.

ESS must manage each of the five CDCs' share of Columbia Transmission's pipeline and storage capacity. For each of the five, that management process involves gas-purchase decisions, some made monthly, some intra-month, and some daily. Decisions are made regarding a) taking flowing gas under CKY's term contracts, b) injecting gas into storage, or withdrawing gas from storage, depending on load conditions and storage levels, and c) buying additional spot gas if necessary.

All of these decisions are currently made in the context of capacity contracts (and capacity operating conditions) that are fixed until late 2004. In fact, ESS reports that CKY's capacity contracts are about right, although contract adjustments will be sought to move delivery rights among delivery points.

In Chapter 1, Gas Supply Planning, Liberty observed (and, indeed, ESS confirms) that CKY's current relationship between its load and its capacity portfolio requires buying some spot-market gas on peak under fairly extreme weather conditions. CKY has a theoretical design-day shortfall equal to about 5 percent of its demand. This would be the case if CHOICE marketers had taken assignment of all of the capacity available to them. Since they did not, CKY is able to cover 100 percent of its design-day demand with contracted firm capacity. In fact, ESS bought spot gas for CKY during the winter of '00/'01. These purchases, as described elsewhere in this chapter, were the result of extreme seasonally cold conditions, not extreme or design daily cold conditions. In the past, ESS has used peaking capacity to manage some of this requirement. (See, *e.g.*, the contract for peaking service from Columbia's Cove Point LNG facility, shown in Table 3.1 above.) ESS indicates that, as the impact of CKY's Customer CHOICE Program on CKY's requirements for capacity are resolved, and as operating conditions on Columbia Transmission's storage and pipeline capacity are adjusted as part of the 2004 contract renewal process, ESS may look again at serving part of CKY's requirements with peaking capacity.

(4) Negotiation and Renegotiation of Contracts

As noted earlier, CKY's capacity contracts primarily are long-term agreements with affiliates Columbia Gulf Transmission and Columbia Gas Transmission. Some negotiation takes place in the context of pipeline rate proceedings, but the scope of those negotiations is usually limited to cost-allocation issues.

As CKY heads into the 2004 contract-expiration process, its CHOICE Program is creating some uncertainty. CKY has had an unexpectedly strong response to the Program, which has meant that the Company is now in the mandatory-capacity-assignment phase (Phase 2) of the Program. The purpose of that phase was to limit the impact of customer switching on the customers who decided to stay with CKY.

In response to concerns about whether participating suppliers were providing their customers with the required degree of supply reliability, CKY has sought to amend the Program to require mandatory capacity assignment for all of its customers. Discussions are currently ongoing regarding this change.

The CHOICE Program changes the quantity of gas that ESS needs to buy for CKY's customers. The CHOICE Program also impacts CKY's requirement for pipeline and storage capacity. Whether, and how much, Customer CHOICE changes CKY's capacity requirements is a function of a) whether mandatory capacity assignment is required for all CHOICE customers, and b) its role as the provider-of-last-resort (POLR). If mandatory capacity assignment is not required, meaning CKY must hold supply resources in order to provide supply when other suppliers fail, then its capacity requirements will be impacted. These uncertainties affect not only how much pipeline and storage capacity that CKY will need, but also questions such as whether to seek peaking capacity, and, if so, how much.

For gas supply, the RFP process that ESS uses for term contracts effectively provides annual renegotiation of everything. Soon after implementation of Order 636, multi-year contracts for gas supply were common. Over time, however, contracts have become shorter and more flexible. With the change to shorter-term contracts, ESS is able to re-bid almost all of its term commodity requirements every year.

ESS has particular objectives for each year's solicitation. In general, those objectives have to do with a) increasing ESS's ability to change its nominations within a month in response to load conditions, and b) driving down prices.

(5) Contract Terms and Conditions

The contracts that govern CKY's relationships with Columbia Gulf, Columbia Transmission and Tennessee Gas Pipeline are service agreements pursuant to FERC Gas Tariffs. Those terms and conditions can be addressed in the context of pipeline rate proceedings at the FERC; in general, however, there is little possibility of bilateral negotiation about them.

For commodity, over the period since implementation of Order 636, ESS has moved to use of a modified Gas Industry Standards Board (GISB) base agreement with all suppliers. ESS finds that these contracts are satisfactory, and using them saves time that might otherwise be spent haggling with suppliers.

ESS uses an asset-management agreement for its capacity on Tennessee. This agreement is for both supply and asset management services. It is re-competed annually.

(6) Peak Period Performance

Under current CHOICE program operations Columbia is able to rely solely upon firm supplies and capacity to meet its sales customers' design peak-day demand. CKY contracts for sufficient term gas to fill its firm transportation capacity during the core winter months (December – February). Columbia also fills its storage capacity and manages inventory to maintain full deliverability into February. As previously noted, should Columbia's request to convert its CHOICE program to mandatory assignment be approved, Columbia would either contract for additional capacity or purchase minor levels of spot gas supplies on a design peak day to satisfy sales-customer requirements.

During the winter of '00/'01, ESS bought spot gas as storage was drawn down to a level below their operating targets. That winter did not have extreme peaks that would have required extra supplies on particular days. Rather, the weather pattern in the late fall and early winter (the November - December period was one of the coldest such periods ever) was one of sustained cold, which required storage withdrawals ahead of schedule. Spot-market gas was bought in those months to support storage inventory, thus ensuring Columbia had enough gas supplies and storage deliverability to last through the winter in the event that the cold weather continued.

CKY did not have any supplier delivery failures during the winter of '00/'01. Two suppliers to the CHOICE Program failed in the early months of the Program, but the amounts of gas involved were so small that CKY handled them easily out of storage.

(7) Price Risk Management

The CDCs view their storage position as a significant stabilizer of gas prices for their customers. CKY reports that about half of its core-market winter demand is served from storage, with gas that was bought during the storage injection season, when gas prices are generally lower than during the storage withdrawal season.

CKY points out that the option most recently available to its customers through its CHOICE Program involved fixed prices. Thus, CKY reasons, if its customers wanted a hedged price, it was available to them through that program.

While CKY does not prefer price-risk management, or price stabilization, through the use of financial instruments or fixed-price contracts, ESS is conducting hedging programs using those devices for three of the five CDCs that it serves. In those States, the public utility commissions were in favor of the programs, and ESS developed them in response to that interest. ESS will develop a program for CKY if the KYPSC insists, but does not currently recommend it.

c. Conclusions

(1) The rate structure on Columbia Gas Transmission makes Columbia of Kentucky's gas costs high. (*Recommendation #1*)

NiSource has two transmission subsidiaries that provide service to CKY, Columbia Gulf Transmission Company (Columbia Gulf) and Columbia Gas Transmission Corporation (Columbia Transmission). Columbia Gulf brings gas from the Gulf Coast Producing Region to Columbia Transmission. Columbia Transmission, in turn, moves the gas to affiliated and unaffiliated LDC customers in eleven States, most of which are north and east of Kentucky.

The terminus of Columbia Gulf is at Leach, Kentucky (which is near where Ohio, Kentucky and West Virginia come together). Much of Columbia of Kentucky's (CKY) service territory is upstream of this point; thus, in those areas the only Columbia Transmission facilities that CKY directly uses are those lines in Kentucky between Columbia Gulf and CKY's city gates. Columbia Transmission's rates are not zoned, largely because, as described on page III.A.3.3, Columbia Transmissions system is a reticulated or net-like system, with supplies coming in at multiple points across its territory and gas being delivered off of it throughout that territory, with storage fields more or less in the middle of that territory. Because the rates are not zoned, however, CKY pays the same rates for the services that it receives from Columbia Transmission as customers located at the far downstream end of the Columbia Transmission system – in northern New Jersey and southern New York, for example.

A consequence of this rate and physical structure is that, while CKY's gas costs are always the highest in Kentucky, costs for Columbia Transmission's downstream customers tend to be lower than their peers. Columbia of Pennsylvania, for example, has among the lowest gas costs of the LDCs in Pennsylvania.

The effect is not as pronounced for the half of CKY's gas that is delivered from storage. CKY and ULH&P buy storage services from Columbia Transmission. Those services are priced as though gas flows past them in the summer, to storage fields located in Ohio, Pennsylvania and West Virginia, and then flows back to them from those fields in the winter. The summer/winter movements in and out of storage are the same for Columbia's downstream customers (even though the flows are in different directions), so the effect of the rate structure on the price that the LDC customer sees for those services is the same.

(2) The rate structure impacts CKY's Customer CHOICE Program. (*Recommendations #1 & #2*)

CKY was assigned transmission and storage capacity on Columbia Transmission and Columbia Gulf in the FERC Order 636 implementation process. While CKY's capacity on Tennessee Gas Pipeline (TGP) has since expired and has been renewed, its Columbia Transmission and Columbia Gulf capacity are under contracts that do not expire until 2004.

CKY's system-supply load has shrunk considerably due to its Customer CHOICE Program. Initiated in late 2000, CHOICE has resulted in over one-third of CKY's eligible customers switching to alternative suppliers. The structure of the CHOICE program has meant that customers who switch to alternative suppliers have had to effectively take their capacity with them since the Program entered Phase 2. Any extra capacity that remained with CKY as a result of marketer decisions during Phase 1, beyond that needed to serve its remaining sales customers' peak-day demand, has its costs removed from the GCA and CKY is placed at risk for recovery of those costs. CKY is able to fund this risk through 1) revenues received from balancing fees paid by CHOICE marketers, 2) a 75 percent share of all off-system sales net revenue, and 3) a "marketer contribution" which is a throughput charge of 5 cents per Mcf on all CHOICE volumes. CKY is at risk if the stranded capacity costs are not fully funded by these revenue streams.

(3) CKY's secondary-market activity is beneficial, but these proceeds by themselves are not offsetting the cost of carrying the extra capacity. (*Recommendation #1*)

CKY reports that off-system sales margins generated $5.6 million in 2000, and capacity-release revenues amounted to almost another $1.0 million. Customer CHOICE began in late 2000, so 2000 is the last year that is largely unaffected by that program. Even assuming that 100 percent of these revenues were credited against GCA costs, those proceeds amounted to only about 33 cents per Mcf of sales, well below estimated capacity costs of $1.36 per Mcf. (Columbia has reported sales for the year 2000 as 20,145,247 Mcf.) As part of the Customer CHOICE Program, CKY is allowed to keep 25 percent of off-system sales margins, so only 75 percent of secondary-market revenues are available to offset capacity costs. (It should be understood that implementing the CHOICE program has not resulted in extra capacity and that capacity costs to sales customers have not increased due to the program.)

(4) Gas supply operations are a strength at Columbia.

Columbia Gulf and Columbia Transmission have over 16,000 miles of pipeline, and Columbia Transmission has 44 storage fields in four States, with 240 Bcf of working-gas capacity. ESS manages 1,500 delivery points, on those pipelines and others, over a five-State service territory.

Gas movements to all those delivery points are quite complex. Each of the five CDCs has its own set of contracts, each of which has specific parameters within which its operations must be managed. Moreover, all five of the CDCs have Customer CHOICE Programs.

ESS uses intensive planning and management to effectively coordinate all of these complex operations. At the center of that process, in Liberty's view, is the CDCs' Winter Operations Plan process. As part of that process, Winter Operations Plans are developed for each of the market areas on the Columbia Transmission system that are operated by ESS.

Seven of the market areas are in Kentucky, and six of those are operated by ESS for CKY. (The other serves other customers in Kentucky. For each of the ones in CKY's service area, CKY reports on any system upgrades that have taken place since the prior year, and on any developments regarding the load during that period. Specific recommendations regarding operations are included for each market area, and critical monitoring and control points are identified.

The Winter Operations Plan process starts in the fall with analysis of system and load changes by each of the Columbia LDCs. Representatives of each of the five then gather in Columbus, usually some time in October, to go over their new information with Gas Control, and to discuss their plans with the other groups within ESS. Winter Operations Plans are finalized after those meetings, at which point both ESS and LDC personnel have detailed parameters and strategies for operating each market area.

ESS also prepares the Gas Operations Guide, a procedures manual that describes their ongoing processes. The Guide is updated annually, and is furnished to LDC personnel to inform them about planning and operations processes conducted by ESS. This Guide presents clearly what ESS is doing to discharge its responsibilities for supply operations, but it also makes clear the role of local personnel in keeping the system going.

Liberty finds both Columbia's processes and documentation for conducting supply operations to be impressive and commendable.

(5) Columbia has an excellent process for keeping the terms of its gas-supply contracts current.

Columbia's ESS conducts a comprehensive request-for-proposals (RFP) process for gas supplies every year. Proposals are requested for varying term lengths, nomination flexibility and innovative pricing options. When it has responses to its RFP, Columbia identifies, through careful comparisons, the best proposals and then negotiates particular terms and conditions. Once it has the new supply offers, complete with detailed terms and conditions, ESS reviews its existing term supply agreements to see if the new ones are better than at least some of the old ones. If so, previous suppliers are given some opportunity to match the new terms, or the Company will not renew their agreements. Most supply agreements are for some initial period, and then they "evergreen" for some period thereafter. These renewal periods could be month-to-month, season-to-season or year-to-year, depending on the terms of the original contract.

This process results in a culling of the CDCs' commodity contracts, which allows the CDCs to keep the relationships that have good terms, but to replace any whose terms are no longer as good as proposed new ones. In May 2001, for example, 22 suppliers were sent RFPs for firm gas supplies for varying periods during the contract year November 2001, through October 2002. By the end of the process, the CDCs had entered into15 new term-purchase agreements, and had terminated ten from their portfolios. The prior year, the same process resulted in 24 suppliers being sent RFPs, from which two new agreements were concluded, but eight older ones were terminated.

Liberty finds this process impressive, and believes that it results in contracts that continually incorporate the latest terms and conditions available to buyers like Columbia.

(6) CKY's storage mitigates price volatility. (*Recommendation #3*)

Not counting CKY's CHOICE Program customers, 46 percent of its winter-season sales volume comes from storage, and 76 percent of its design-day sendout would come from storage. Thus, CKY feels that stored gas provides a significant hedge for its customers against gas-price volatility.

CKY reports that it needs all of its current storage capacity to serve its winter-period load, and that it requires the full injection season to get its capacity full. Furthermore, again not counting CKY's CHOICE Program activities, CKY utilizes its firm transportation service (FTS) capacity at very high load factors. Thus, any additional hedging would have to be done with financial instruments, rather than with additional storage as trading FTS capacity for storage would require CKY to purchase additional volumes of spot gas during the winter.

d. Recommendations

(1) CKY should work to reduce its gas costs, and to mitigate the effects of Columbia Transmission's postage-stamp rates. (*Conclusions #1, #2 & #3*)

Columbia's ESS group largely concedes that the application of postage stamp rates on Columbia Transmission is a major factor in CKY's perennially high gas costs. ESS reports that it has had little success, however, in getting the problem addressed in Columbia Transmission's rate proceedings, primarily because of CKY's relatively small size and the belief of many customers that a postage stamp rate design is the appropriate design for a reticulated pipeline such as Columbia Transmission. CKY has about 140,000 customers, whereas the five Columbia LDCs serve about two million customers, and Columbia Transmission indirectly serves another five million customers through unaffiliated LDCs. CKY simply has no bargaining power.

This situation is likely to persist until the KYPSC insists that it be addressed. The impending expiration of CKY's contracts with Columbia Transmission and Columbia Gulf provides a time frame for CKY and the KYPSC to work on finding solutions to the problem.

(2) CKY should work with the Commission on integrating impacts of the Customer CHOICE Program into strategies developed for setting the Company's requirements for pipeline and storage capacity. (*Conclusion #2*)

As noted in the discussion above, aspects of CKY's Customer CHOICE Program affect CKY's requirements for pipeline and storage capacity in at least two ways: 1) the total amount of capacity required, and 2) whether extra capacity resources must be reserved for the provider-of-last-resort function. It is important that the Commission be involved in this process as the Company and the Commission work together to address Kentucky's problems with the Columbia pipelines' rates.

The time frame for action on the Columbia pipelines' rates is the next two years, between now and the time when the pipeline contracts expire. Analysis of CKY's positions in those negotiations must start well in advance of that expiration. CKY may need some guidance from the Commission on aspects of the CHOICE Program, or resolution of particular questions about it, in order to prepare for its negotiations with the pipelines. Since Commission decisions will impact CKY's preparations for the negotiations, both CKY and the Commission must be operating with the same set of understandings and objectives.

(3) CKY should work with the Commission, the other Kentucky LDCs and other interested parties to establish a common foundation of objectives for natural gas hedging programs. (*Conclusion #6*)

As discussed in the first section of this report, Liberty believes that the Commission, the LDCs and other interested parties should pause after next winter to review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. Also, Atmos used different hedging techniques in other States in which it operates. The CDCs had hedging programs in three of the five States in which they operate. Kentucky is one of the five, but not one of the three. Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management.

Liberty recommends that a specific area for discussion be the objectives of future hedging programs. In this vein, Liberty applauds the Commission's adoption of the Attorney General's suggestion, presented in the context of consideration of ULH&P's proposed hedging program for '02/'03, that public input be sought in selecting those objectives. Our experience tells us that different customer classes will prefer different objectives. That knowledge will help the Kentucky LDCs to tailor their service offerings more closely to their customers' requirements.

4. Gas Transportation

a. Scope

This chapter of the report addresses CKY's programs for natural gas transportation service. Aspects considered include the following:

- Transportation Programs Offered
- Agency Programs
- Bypass Issues
- "Prodigal Son" Customers.

b. Background

(1) Transportation Programs Offered

CKY offers both a traditional transportation program, and a customer CHOICE pilot program. The following traditional services are offered:

- Delivery Service: Available to any customer who has been a sales customer, and whose requirements exceed 25,000 Mcf/year. The rate for this service is the same as the non-gas portion of the Company's General Service Sales rate.
- Main Line Delivery Service: For customers whose requirements exceed 25,000 Mcf/year, and who are connected directly, through a dual-purpose meter, to the facilities of one of the Company's interstate pipeline suppliers. The rate for this service is 10 cents per Mcf delivered.

Both of those services are also subject to a Banking and Balancing Service Charge, unless they have daily-demand-reading metering equipment. The Banking and Balancing Charge assesses these customers for the costs required for balancing deliveries by their suppliers with their consumption; it is about 2 cents per Mcf of the customer's maximum daily delivery quantity, and is assessed as a demand charge.

Customers for Delivery Service who do not have an alternate fuel source installed on their premises may also be required to contract for Standby (sales) Service. This service is provided pursuant to a Sales Agreement that specifies a Maximum Daily Volume. A demand charge is assessed per Mcf of the Maximum Daily Volume, and the Company's normal sales rates apply for volumes actually taken.

Transportation-service customers also provide their own pipeline capacity, and storage capacity if they need or want it. Other than pursuant to a contracted stand-by service, CKY holds no pipeline or storage capacity for these customers.

The Company reports that essentially all of its large-volume commercial and industrial customers have switched to transportation service under one of those rate schedules. Switching began in the early 1980s, with the early FERC programs for gas supplies to large-volume customers at other than tariff rates. This included programs such as the FERC's Special Marketing Programs, where the pipelines and the LDCs fashioned rates to keep large-volume customers on gas, or to encourage them to switch to gas. State-level rules for contract transportation service by the LDCs came into being in the late 1980s; between 1987 and about 1992, approximately 95 percent of all customers with annual requirements in excess of 20,000 to 25,000 Mcf/year switched.

The Company reports that the 25,000 Mcf/year threshold came out of State-level proceedings in the late 1980s to establish tariffed transportation services. By that time, the Company already had some transportation-service customers with annual requirements below that level, so those customers were "grandfathered".

Table 4.1, below, gives the number of customers and volumes of gas moving under these rate schedules.

Table 4.1 Transportation Customers & Volumes

	Avg. No. of Customers	**Volumes Transported (MCF)**
2001	132	16,839,985
2000	133	21,417,314
1999	145	23,291,547
1998	139	22,228,355

The Company's customer CHOICE pilot program is operated pursuant to a Small Volume Gas Transportation Service (SVGTS) Rate, and a Small Volume Aggregation Service (SVAS) Rate. The nature of those services is as follows:

- SVGTS: Available to customers who are part of a group composed of either a) 100 customers, or b) a group that has an aggregate minimum annual throughput of 10,000 Mcf. The group must be served by a single supplier, who has been approved by CKY. The rate for this service is the same as the non-gas part of CKY's sales-service rate.
- SVAS: Available to suppliers who serve groups that meet the above specifications of 100 customers, or aggregate annual requirements of 10,000 Mcf. This service involves estimating the requirements of the customer group, for which the charge is 5 cents per Mcf, and balancing city-gate deliveries with deliveries to customers. The charge for the latter service is 35 cents per Mcf if the supplier does not take assignment of pipeline capacity from CKY. There is no charge from CKY if the supplier takes assignment of some of CKY's capacity, but the pipelines' balancing provisions (and charges) apply.

SVGTS customers are charged a proportionate share of CKY's lost-and-unaccounted-for volumes (LAUF), but customers for the conventional transportation services are not.

SVAS is used by the suppliers to get their customers' requirements aggregated to the city-gate level, to which point the suppliers can arrange for gas to be delivered. The SVGTS rate gets the gas from the city gate to the suppliers' customers.

Table 4.2, below, shows the numbers of customers and volumes delivered since the CHOICE Program began.

Table 4.2 Choice Program Transportation Customers & Volumes

	Avg. No. of Customers	Volumes Transported (MCF)
2001	36,735*	3,894,661
2000	242	439,434
1999	0	0
1998	0	0
*Customers range from 13,260 in January to 51,039 in December		

(2) Agency Programs

CKY also offers an agency service. For customers who have an alternative source of fuel supply, CKY will find a source of gas and buy it as the customer's agent. The Company will then deliver the gas pursuant to its DS Rate.

The minimum Agency Fee is 5 cents/Mcf. The revenues for this service must be enough to cover the Agency Fee, plus the marginal costs of the gas that the Company finds, plus some contribution to recovery of the Company's fixed costs.

The Company did not report whether it has any customers for this service.

(3) Bypass Issues

CKY has continually had a significant bypass threat. Perhaps the biggest threat is a "default" bypass, where a customer is connected to affiliate Columbia Transmission's facilities, or another supplying pipeline, and the only thing that CKY owns is the meter that measures the flow of gas into the customer's premises. In this circumstance, the rate for service from CKY is only 10 cents per Mcf, but it happens that customers on this rate simply stop paying for CKY's services. The gas supplier and Columbia Transmission get paid, but the customer simply stops paying CKY.

CKY is vulnerable to bypass to other pipelines, as well. Because of the location of some of its service areas, some of its large-volume industrial customers may have other pipelines actually crossing the sites of their facilities. For CKY's customers, other pipelines, or the facilities of other LDCs, are never very far away.

CKY mostly deals with these threats with the "flex" provision of its DS Rate. That provision allows the Company to lower its rate in response to competition. An alternate source of gas supply is considered an alternate fuel for the purpose of invoking this provision of the Rate. CKY reports that it has lost one customer to bypass, and another has installed facilities to take part of its requirements from another supplier.

CKY has also lost five IUS customers. These are very small utility systems within Kentucky served at wholesale by CKY. The five that were lost departed in order to cut CKY out of the stream between the IUS and the interstate pipeline, leaving oneof these customers still being served by CKY.

(4) "Prodigal Son" Customers

CKY reports that, once a customer leaves system supply for transportation service, they virtually never return to sales service, except on an interim basis while they look for a new supplier.

c. Conclusions

(1) The rate structure problem referenced in Chapter 3, Gas Supply Management, may also be a factor in CKY's low realizations from the provision of transportation services. (*Recommendation #1*)

As discussed in the previous chapter of this section of this report, Liberty believes that a principal reason that CKY's rates for natural gas sales service are always high is the postage stamp nature of charges for Columbia Gas Transmission. Liberty is concerned that this structure is affecting CKY's provision of transportation services, as well.

CKY reports that almost every customer who takes a sales or transportation service from CKY pays for transportation on both an upstream pipeline and on Columbia Transmission in the price that the customer pays at CKY's city gate. The exceptions are a small group of customers in the vicinity of the Tennessee direct interconnect referred to as Mavity and those who purchase Appalachian gas production. While actual customer losses have been small, CKY's revenues from transportation services are reduced by the smaller difference between the price delivered to the customer's premises, set by competition with an alternate source of gas, and the cost of supply delivered to CKY's city gates, since the latter has in it transportation charges on two pipelines. Its worth noting that CKY personnel believe that the vast majority of bypass threats exist not because a delivered gas price is high relative to some other price, but because one of the transporters (in this case CKY) can be eliminated. This economic pressure exists whether the plant manger wants to reduce rates from 5.00 to 4.90, or from 2.00 to 1.90. The dime still has to provide the payback for the bypass in either case.

Liberty observes that the treatment of LAUF volumes for CKY's large-volume transportation customers is different from what we would normally expect. While there may be some good reasons for this different treatment – such as when a customer uses no CKY facilities other than a dual-purpose meter – the treatment of LAUF volumes may be another manifestation of value being drained off by Columbia Transmission's charges. It should be noted that CKY personnel do not believe that the treatment of LAUF has anything to do with receiving service from Columbia Gulf and Columbia Transmission.

d. Recommendations

(1) CKY's work with the Commission, recommended in Chapter 3, Gas Supply Management, to address the structural problems in CKY's gas costs, should address the influence of those costs on CKY's transportation revenues, as well. (*Conclusion #1*)

A complete discussion of the background and rationale for this recommendation is contained in Chapter 3, Gas Supply Management.

5. Gas Balancing

a. Scope

This chapter addresses CKY's means and methods for balancing its gas delivery system. Topics addressed include the following:

- Metering and Testing
- Balancing Strategies and Practice
- Assignment to Third Parties
- Reporting.

b. Background

(1) Metering and Testing

In general, Company-use gas is metered. Some gas used for regulator operations is estimated, based on the number of pressure controllers and/or heater elements.

Columbia generates two sets of statistics on lost-and-unaccounted-for volume (LAUF). ESS monitors gas deliveries into CKY's system – from pipelines at gate stations and meters on local production – against expected demand and against pipeline quantities scheduled for delivery to its system. Once per year, ESS accesses billing records to obtain full-year measured deliveries to all customers, for comparison with measured receipts into CKY's system. Any difference, after adjusting for any known prior-month adjustments in supply or demand and for Company-use gas, is LAUF. The LAUF calculation is done for a 12-month period ending in August of each year, as that is the point when required adjustments (for unbilled quantities, imbalances, etc.) are lowest. CKY incorporates this data into its reports to the U.S. Department of Transportation's Office of Pipeline Safety, and also uses it to initiate inquiries into possible reasons for differences between measured supply and demand if the number is larger than what is considered to be normal (plus or minus two percent). ESS-generated LAUF factors are used by CKY in the computation of its gas-cost adjustment, and are included in the CHOICE customer demand profiles provided to marketers for their use in scheduling supplies on behalf of CHOICE customers. (As noted in Chapter 4, larger-volume transportation-service customers are not assessed a share of LAUF.)

Gas accounting is performed by a different group in Columbus. For financial reporting of LAUF quantities, metered/billed receipts into CKY's system are added up, and compared with the total of all of the readings from CKY's customers' meters, again adjusted for Company-use gas. This assessment is conducted monthly. As noted, this assessment is used for financial reporting purposes only.

The following table presents the two sets of LAUF percentages over the last five years:

12 months ended August 31	ESS LAUF, percent	Accounting LAUF, percent
1997	+3.48	-6.1
1998	+0.50	-3.2
1999	+0.93	-0.4
2000	+1.36	-1.7
2001	-0.50	+2.0

The Company reports that the difference between the two sets of LAUF numbers is that prior-month adjustments to measured deliveries are recognized and accounted for in ESS's numbers, but that adjustment is not made to Accounting's numbers.

CKY uses a statistical meter-sampling plan for testing its meters. The plan was initiated in 1996 as a five-year pilot program, and was approved by the Commission for permanent use in February 2001.

(2) Balancing Strategies and Practice

ESS's approach to balancing is to estimate its customers' requirements continually, and to manage its takes to match requirements with supply. Customer demand for the next five days is estimated twice a day from September 15 through June 15. Demand estimation drops back to once per day during the summer months.

Supply to CKY is made up of three components:

- CKY's system-supply purchases, both term and spot;
- Deliveries of customers' (transportation) gas; and
- Gas from storage.

Gas from storage is CKY's primary "swing" supply; *i.e.*, the supply available on a no-notice basis to meet incremental differences between flowing supplies and actual demand.

Transportation-service customers nominate their supply to be delivered to CKY via an electronic nominations system managed by ESS. ESS confirms nominations and receipt of the gas. Large-volume customers, or their suppliers, nominate their supply, typically on the basis of their expected consumption. Requirements for CHOICE Program customers are nominated by their suppliers on the basis of customer load profiles developed and provided by CKY.

Gas used by transportation customers is metered continuously. Use is compared monthly with deliveries to CKY on their behalf, unless load conditions require more-frequent monitoring of the balance between the gas that is being delivered for them and the gas that they are using. The Company may compare the supply and use of larger customers within a day, and/or at the end of each day, in instances where the customer's activity can influence the Company's local operations, or operations involving delivering pipelines.

Gas use by CHOICE customers takes longer to reconcile. The Company can compare the suppliers' deliveries to CKY's city gates to their nominations on a monthly basis, and any imbalance between those totals can be resolved then. Reconciling supplier deliveries with customer use is generally done on an annual basis, to accommodate the realities of meter-reading schedules and cycle billing. The need for a longer-period reconciliation between estimated and actual customer use, typically done annually, is a feature of virtually all small-volume transportation programs.

The costs of providing balancing services are recognized in CKY's rate structure. Transportation-service customers, except for Flex and Special Contract customers, are assessed a Banking and Balancing Delivery Rate, currently about 2 cents per Mcf consumed. This charge is based on the costs required to provide the service, and is recomputed as part of each GCA filing. The pipeline transportation and storage capacity reserved by CKY to fulfill its firm service obligations to its sales and CHOICE customers is used to provide the Company's Banking and Balancing Service on a non-firm basis. Suppliers to the CHOICE Program are charged 35 cents per Mcf delivered to CKY for balancing if they elect not to take assignment of storage capacity from CKY. If they take assignment of a designated minimum volume of CKY's storage capacity on Columbia Transmission, the charges for balancing are reflected in the charges for the assigned capacity.

(3) Assignment of Capacity to Third Parties

CKY (or ESS on CKY's behalf) does three types of capacity assignments: administrative releases, assignments to CHOICE Program suppliers pursuant to the voluntary- or mandatory-capacity-assignment aspect of the Program, and "marketed" releases. Administrative releases are used for the asset-management arrangements that ESS uses in some cases to manage capacity on pipelines other than the Columbia pipelines. CKY's Tennessee capacity is operated under one of these arrangements. Administrative releases are made at maximum (FERC Tariff) rates, and revenue from those releases is credited to the Company's gas costs.

Assignments to CHOICE Program suppliers are made on the basis of estimates of their customers' requirements. The amount of capacity assigned is adjusted for "grandfathered" capacity (*i.e.*, capacity held by the suppliers for customers that had signed up for their service before May 15, 2001), and divided among transportation capacity on Columbia Gulf, and transportation and storage capacity on Columbia Transmission, on the basis of rules developed by ESS to mimic the various rules that apply to the operation of that capacity. CHOICE marketers may elect to take assignment for portions or all of the capacity required to serve their grandfathered customers. As with the administrative releases, assignments to CHOICE suppliers are made at maximum rates, and for a term of one year, to the point when their customers could select another supplier.

After adjusting the amount of capacity under the Company's control for those two types of assignments, ESS evaluates whether CKY has capacity that is likely to be surplus to its requirements, and thus available to be posted on the pipelines' electronic bulletin boards. These evaluations are made monthly, and the quantity to be posted is adjusted monthly. Bidding and awarding procedures follow those specified in the FERC Tariff of the pipeline whose capacity is being released, and contractual arrangements are handled by the pipeline. Proceeds of the release are whatever the market brings, and are credited to the Company's gas costs.

(4) Reporting

The Commission's order approving CKY's proposal for its Customer CHOICE pilot program called for annual reports on the progress of the program, with the first one due June 1, 2001. The Company also reports monthly on rates currently being offered by participating suppliers to the program. Liberty was provided with copies of all reports submitted to date, including the Annual Report for 2002.

c. Conclusions

(1) The costs of balancing, for both large-volume and small-volume customers, are recognized and addressed in CKY's rate structure.

CKY has long had a gas-transportation load that is large relative to its sales load. Moreover, the Columbia Transmission system is particularly complex because of its many receipt points and delivery points. Thus, the costs of the facilities and services that CKY requires for system balancing are substantial.

Balancing is also one of the most difficult aspects of a small-volume transportation program, such as Customer CHOICE, as the LDC must manage both any mis-estimation of customer requirements, and any differences between customer requirements and supplier deliveries.

CKY's transportation programs address both of these concerns. CKY's rates for large-volume transportation services include a Banking and Balancing Service charge, assessed as a delivery charge on a customer's actual consumption. For the small-volume transportation program, CKY's Small Volume Aggregation Service includes balancing for those suppliers that take assignment of Columbia Transmission and Columbia Gulf capacity (the pipelines provide the balancing service), but imposes a balancing charge of 35 cents/Mcf for suppliers who provide their own pipeline capacity. CKY also provides customers with gas, and bills the supplier for CKY's costs, in the event that the supplier does not deliver enough gas.

(2) The possible consequences of Columbia's approach to LAUF accounting should be explored. *(Recommendation #1)*

As noted above, Columbia develops two sets of LAUF numbers, one for "gas-tracking" purposes, and one for financial-reporting purposes. Company representatives report that the two computations use the same data sources – metered deliveries into the system and metered deliveries out – but are getting different results. As also noted above, the principal difference between the two is thought to be that ESS accounts for adjustments in prior-month measured deliveries, attributing them to the proper delivery month, whereas Accounting does not.

As also noted above, ESS's figures are used for the purposes normally associated with LAUF reporting – to the U. S. Department of Transportation for its purposes, and in specifying retainage for transportation-service customers. (In Columbia's case, only CHOICE Program customers are assessed retainage.) The Company reports that Accounting's figure is used only for financial-reporting purposes.

The existence of two sets of numbers, and the difference between them, is a first for Liberty. We do not know whether this is a problem that the Commission should be concerned about. Both sets of numbers are mostly within the range generally considered acceptable (plus or minus two percent), and the smaller one is used for purposes that have consequences for customers. Liberty's problem is that we have not heretofore been presented with two sets of numbers, and we don't know whether to be concerned about it. It could be that all companies have two sets of numbers in this area, but only ever told us about one of them. We simply don't know.

Liberty also does not know whether the ways that CKY uses the two sets of LAUF numbers makes enough difference to warrant additional efforts to reconcile them. Liberty is concerned that the referenced adjustments to prior-month deliveries may not be the only reason for the difference, and that failing to reconcile the two sets of numbers may be masking other effects that could be causing other inequities. Liberty feels that, at least one careful reconciliation of the two sets of numbers should be done. The objective of the reconciliation would be to assure the Company and its customers that the referenced measurement adjustments are indeed the reason for the difference in the two sets of numbers.

d. Recommendations

(1) CKY should report to the Commission on its LAUF accounting. *(Conclusion #2)*

As noted above, Liberty does not know whether Columbia's practices regarding LAUF accounting are problematic, because we have not seen this before. We recommend that Columbia contact the other Kentucky LDCs regarding their LAUF accounting and reporting practices, and report to the Commission on its findings.

Soon, both ESS and CKY Accounting will be preparing their LAUF assessments for the past year (September, 2001 through August, 2002). Liberty recommends that the Company work to carefully reconcile the two sets of LAUF data, and report on its efforts to the Commission. The Company's report should also address whether its LAUF assessment/retainage practices are affecting any groups of its customers any differently from any other groups.

6. Response to Regulatory Change

a. Scope

This chapter of the report addresses CKY's response to the changes in its regulatory and business environment, particularly since the issuance and implementation of the FERC's Order 636. Topics addressed include the following:

- Changes in Objectives for Supply
- Changes in Supply Activities
- Capacity Cost Reduction.

b. Background

(1) Changes in Objectives for Supply

For the Columbia distribution companies (CDCs), the Order 636 implementation process resulted in replacement of its long-term contracts with the Columbia pipelines originally entered into effective November 1, 1989. Capacity contracts for all of Columbia Transmission's LDC customers originally issued as part of implementing Order 636 run through October 2004.

Since Order 636 implementation, ESS has focused its efforts on operating its capacity contracts efficiently, and on improving the terms of its commodity contracts. ESS has been aware that CKY's gas costs are higher than those of the other Kentucky LDCs, but has attributed the differences to "natural advantages" held by the others, such as on-system storage. ESS concluded that, "… when restated on a comparable basis, CKY's [gas cost] is 1 cent lower than the average of its peers." Liberty feels that such explanations do not focus appropriately on the root cause of the problem with CKY's higher rates for natural gas, and provides a more complete discussion of this issue in Chapter 3, Gas Supply Management. ESS has had to deal with the constraints imposed by its long-term contracts and by the fact that others had on-system storage and/or economic access to alternative capacity providers while CKY had no practical, cost-effective alternative to buying its storage and transmission capacity from Columbia Transmission. Thus, it chose to focus on the things that it could do something about in the near term, namely gas-supply operations and buying gas.

In 1999, following up on the Commission's interest in unbundling as expressed in Administrative Case No. 367, CKY proposed a small-volume gas transportation service program that has been called Customer CHOICE^{SM} (*CHOICE*). [Note: Columbia may implement and publicly refer to its small volume transportation program as Customer CHOICE^{SM} and/or CHOICE$^{®}$. Customer CHOICE^{SM} is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Kentucky, Inc. CHOICE$^{®}$ is a registered service mark of Columbia Gas of Ohio, Inc., and its use has also been licensed by Columbia gas of Kentucky, Inc.] The other CDCs had CHOICE programs in place in the States in which they operate. When initially implemented these programs were viewed as an opportunity for the Columbia

System to be in front of the curve in providing choices to customers, and through unregulated affiliates, try to derive some revenue from the commodity sale of gas. An activity that, while it consumes large amounts of time and energy for the LDC to administer, has traditionally been conducted on a pass-through basis, yet carries with it the risk of cost recovery should costs fail to meet the test of being "prudently incurred". Implementation of CHOICE in CKY's service territory was also viewed as an opportunity to extend the then expiring off-system sales program in conjunction with accepting risks related to stranded costs, as an alternative to a gas-cost performance-based rate-making mechanism. The Company's proposal was approved in the first half of 2000, and went into effect in late 2000.

(2) Changes in Supply Activities

Gas supply operations for the CDCs have always been conducted on a centralized basis, from Columbia of Ohio's offices in Columbus. Many of the senior ESS personnel have been in gas supply for the CDCs since they have been with Columbia; what has changed is the nature and scope of gas-supply activity. Prior to Orders 436 and 636, ESS's predecessors forecast demand in order to tell the pipeline how much to supply. As the FERC has required the pipelines to get out of the gas-supply business, ESS has taken over those responsibilities.

ESS's activities after Order 636 have involved managing capacity contracts and buying gas. These activities occur year-round, due to the complexities of operating storage and transportation services on the Columbia Transmission system. Beginning in 1994, off-system sales and capacity release have been a part of those activities as well.

The newer activities for ESS are those required for managing the CHOICE Program. While the CDCs now have CHOICE Programs in all five of their States, the Programs are different and administration is difficult. Required activities include a) estimating demand for each supplier's customers, b) taking nominations from all suppliers, c) reconciling deliveries with customer usage, d) releasing and managing capacity assignment and e) getting the correct gas cost on every customer bill.

CKY does not propose to exit the merchant function, so ESS's emphasis on efficient and reliable gas-supply operations continues, along with its administration of the CHOICE Programs.

(3) Capacity Cost Reduction

As noted above, CKY is unable to reduce its Columbia capacity costs through contract reduction before late 2004, as its contracts are fixed until then. As also noted earlier, CKY's contract for capacity on Tennessee Gas Pipeline has expired, but that contract was renewed, as the capacity is required for providing service to certain parts of CKY's service area.

As also noted earlier, CKY's current capacity portfolio is not in excess of its customers' requirements; if anything, it is currently slightly (5%) deficient. Thus, as long as CKY is required to provide capacity to serve its customers' requirements, capacity cost reduction would have to come from substitution of lower-cost capacity for that currently in the portfolio, rather than through a reduction in the amount of capacity under contract.

ESS has had an active program of off-system sales and capacity releases since soon after implementation of Order 636. Margins generated for CKY by those activities over the last three years are as follows:

Year	Margins from Off-System Sales ($)	Revenues from Capacity-Release Transactions ($)
1999	5,572,741	188,880
2000	5,592,468	196,359
2001	9,615,941	352,401

The "Margins from Off-system Sales" includes the asset management fee. The "Revenues from Capacity-Release Transactions" for calendar year 2000 differ from the $1 million stated in Chapter 3 due to the amounts in this table being net of capacity releases for the CHOICE Program and for CKY's asset-management arrangement. For comparison, CKY's total capacity costs are $23.0 million per year. As part of the CHOICE Program, CKY retains 25 percent of off-system sales margins.

c. Conclusions

(1) CKY is unique among the five Kentucky LDCs in <u>not</u> diversifying its gas sourcing. (*Recommendation #1*)

Diversification of gas-supply sourcing has been a common strategy among Kentucky LDCs as they have sought to lower their overall gas supply costs. LDCs of any size virtually everywhere in the U. S., including those in Kentucky, have added pipeline connections in order to accomplish this diversification since implementation of the FERC's Orders 436 (late 1985) and 636 (November 1993). LDCs in the eastern and northeastern U. S. that have accomplished such diversification include a number of companies that were full-requirements customers of Columbia Transmission prior to the FERC's efforts to open up wholesale gas markets. For example Cincinnati Gas & Electric/Union Light Heat and Power has accomplished such diversification, to their advantage.

CKY's response to the question of why it has not diversified is that it has done studies of possible diversification, but "the numbers don't work". Furthermore, CKY's existing capacity portfolio of long-term contracts did not provide CKY the opportunity to reduce contract levels and replace such capacity with other lower cost capacity resources. While Liberty has not reviewed CKY's studies, the Company's proximity to other pipelines, and the experience of so many other LDCs, leads Liberty to conclude that CKY should focus efforts on finding economic opportunities to diversify gas supply.

d. Recommendations

(1) The study effort recommended in Chapter 3, Gas Supply Management, must include studies of gas sourcing alternatives, as well as studies of alternative rate structures. (*Conclusion #1*)

Irrespective of whether CKY remains in the merchant function, gas costs to CKY's customers will be higher than the other Kentucky LDCs unless or until CKY can cost-effectively bypass Columbia Transmission or reduce the Columbia Transmission rates for at least part of its load, as ULH&P has done. Liberty recommends that the study effort recommended in Chapter 3, Gas Supply Management, involving the Commission and the Company, include study of physical alternatives to access gas supplies, as well as studies of alternative rate structures on Columbia Transmission.

7. Affiliate Relations

a. Scope

This chapter of Liberty's report addresses the affiliate relations aspects of Columbia Gas of Kentucky (*CKY*) gas procurement practices:

- Structure of Affiliated Companies.
  - Placement and Structure of the Gas Procurement Function within the Affiliated Companies.
- Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.
  - Non-Gas Transactions with Affiliated Companies.
- Accounting and Reporting Issues for Affiliate Transactions.
  - Cost Allocation Manual (CAM).
  - Allocation of Employee Time and Overheads.
  - Other Accounting Issues.
- Affiliate Transactions Relative to KRS 278.
- Other Issues.

b. Background

(1) Structure of Affiliated Companies and Placement of Gas Procurement Function

CKY, a Kentucky corporation, is a wholly-owned subsidiary of Columbia Energy Group (*CEG*), a Delaware corporation, operating under CEG's Distribution Operations segment. In addition to CKY, there are four other Columbia gas distribution companies, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Columbia Gas of Virginia. Three other CEG operating segments are Gas Transmission and Storage (including subsidiaries Columbia Gas Transmission Corp. and Columbia Gulf Transmission Co. pipelines), Exploration and Production Operations, and Other. CEG is a registered holding company under the Public Utility Holding Company Act of 1935. The parent company of CEG is NiSource Inc., a Delaware corporation, which is also a registered holding company under the Public Utility Holding Company Act of 1935. Energy Supply Services (*ESS*), which provides gas procurement services for the Distribution Operations segment, is part of Nisource Corporate Services, a Mutual Service Company under the Public Utility Holding Company Act of 1935, that supplies management services to various affiliates within Nisource Inc. A gas marketing company, EnergyUSA-TPC Corp. is a subsidiary of NiSource.

(2) Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

CKY receives gas procurement and gas control services from Energy Supply Services, as do the other four Columbia distribution companies. CKY holds its own commodity supply, transportation and storage agreements, so that gas supply costs are easily tracked to each LDC, as are capacity release and off-system sales revenue as appropriate. The contracts all have a clause that allows for delivery to any one of the affiliated LDCs, which maximizes flexibility. If gas is delivered to a different LDC than the one named on the contract, the transfer is made at cost. The ability to aggregate gas requirements for all five (5) LDCs provides the opportunity for Columbia Gas of Kentucky to "look bigger" to suppliers, promoting a stronger negotiating position for the utilities. This shared services model allows for fewer employees to provide the necessary services and a reduction in overhead costs.

ESS has had limited transactions with EnergyUSA-TPC, an affiliated gas marketer. The gas marketing affiliate has not provided large volumes in the past, and only occasionally provides spot gas to ESS. ESS also purchases gas from affiliated company Columbia Natural Resources (*CNR*) in order to supply local requirements served by CNR's gas gathering system.

CKY's primary affiliated transactions are gas transportation agreements with its sister company pipelines, Columbia Gas Transmission and Columbia Gulf Transmission. In addition to providing firm capacity, the pipelines offer storage services for CKY, and the other Columbia distribution companies, as well as other non-affiliated customers. Transactions are at filed tariff rates.

(2a) Non-Gas Transactions with Affiliated Companies.

Columbia Energy Group and CKY are provided with some administrative and financial services from affiliated companies which are allocated by the service provider to subsidiary companies.

(3) Accounting and Reporting Issues for Affiliate Transactions

(3a) Cost Allocation Manual (KRS 278.2205)

CKY states it is not required to file a cost allocation manual (*CAM*) with the Commission because its revenue from non-regulated activities does not exceed the required threshold. The use of a shared services organization, however, and therefore the allocation of those shared costs among regulated and/or unregulated affiliates, means that the Commission needs to understand how that process is accomplished. The allocation of shared costs has been provided to the Commission pursuant to reporting requirements of the NiSource and CEG merger. The allocations are approved by the SEC and the Commission is provided with any updates. The allocations are also reviewed in rate cases before the Commission to understand the appropriate recovery of costs. Columbia's gas cost does not contain any corporate service allocations. The allocation of shared corporate costs is recovered entirely in base rates that are established upon the Commission's review.

(3b) Allocation of Employee Time and Overheads

Allocating Gas Management Services employee time is based upon an electronic timesheet system that is continuously accessible to employees via their PC. Timesheets are approved by each employee's supervisor at the end of every month. All employees account for their time by day. When appropriate, employees direct-charge time to a specific LDC affiliate, and remaining time is allocated among the distribution companies based upon a code factor. The code pattern is pre-determined for each employee or department section. Interviewed employees were not sure what the code pattern was based upon for various types of costs or when the code pattern was reviewed for continuing applicability.

(3c) Other Accounting Issues

Columbia's consolidated chart of accounts has subaccounts for affiliate transactions, which is a good model for other LDCs in how to meet the FERC Uniform System of Accounts statement that "each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies." Between or among affiliates within Columbia Energy Group (CEG), accounts are settled by intercompany transfer, including transportation invoices from the affiliated pipelines. Between CEG and NiSource, accounts are settled with a cash instrument, because SEC approval has not been obtained to do intercompany transfers.

(4) Affiliate Transactions Relative to KRS 278

CKY's transactions with its affiliate pipelines are at FERC tariff. Purchases by CKY from the affiliated gas gathering company (Columbia Natural Resources – CNR) are at a rate similar to that paid by unaffiliated companies in KY. The fact that other, similar contracts exist between CNR and unaffiliated parties implies the transactions are at market prices. CKY states that the market-price transactions meet the requirements of the Securities and Exchange Commission (SEC) under the jurisdiction of the Public Utility Holding Company Act of 1935, and that CKY's purchases of gas from CNR are consistent with the SEC cost allocation methodologies applicable to CKY and NiSource affiliates.

c. Conclusions

(1) The service company model of Energy Supply Services/Gas Management Services has several benefits for Columbia.

This shared services model allows for fewer employees to provide the necessary services and a reduction in overhead costs. The ability to aggregate gas requirements for all five (5) LDCs also provides the opportunity for Energy Supply Services to "look bigger" to suppliers, promoting a stronger negotiating position for the utilities.

(2) Time allocation procedures provide for recording specific time spent on the appropriate distribution utility; all other time is allocated based upon a code pattern for each employee or department section. Time is submitted monthly. *(Recommendation #1)*

Time reporting is part of the overall issue of cost allocation by a shared services group to regulated and non-regulated affiliates. The direct charging of time to specific distribution utilities is appropriate, and it is the preferable method when possible. The use of a code pattern for remaining time is also appropriate, although those interviewed employees asked were unable to explain upon what basis the code pattern was established or when it was reviewed. Clearly stated time allocation policies and methods in a Cost Allocation Manual would allow both NiSource/Columbia employees and the Commission to better understand and respect the process.

An issue with monthly time reporting is the possibility that time sheets are filled in at month-end, rather than daily, when the information is still fresh in employees' minds. Several management employees stated they tracked and recorded their time daily.

(3) Each of the Columbia LDCs contracts for its own gas supply and pipeline capacity, so that tracking gas supply costs is straightforward.

Each contract has a specific Columbia LDC name attached to it, so the expense associated with a purchase is easily booked to the appropriate utility.

(4) Columbia's chart of accounts has subaccounts for affiliated company transactions, in accordance with FERC Uniform System of Accounts. This method of tracking affiliate transactions can serve as a model for other LDCs.

Use of subaccounts under accounts for transactions of a similar nature is a straightforward way for utilities to ensure that statements of transactions with affiliated companies can be furnished accurately and expeditiously, as required by the FERC Uniform System of Accounts. Columbia's chart of accounts is an example of how those subaccounts can be used. Liberty has found that other utilities depend upon searches by affiliate vendor names, for example, in order to detail affiliate transactions.

(5) Columbia does not have a Cost Allocation Manual (CAM).

CKY states it is not required to file a cost allocation manual (*CAM*) with the Commission because its revenue from non-regulated activities does not exceed the required threshold in KRS 278.2205. The use of shared services organizations, however, and therefore the need to allocate those shared costs among regulated and/or unregulated affiliates, means that the Commission needs to understand how that process is accomplished. This understanding is accomplished in Kentucky through ongoing reporting requirements and general rate cases before the Commission.

As noted above ESS reviews annually, and changes as necessary, the allocation code pattern to apply in the following year. The selected code pattern is one that is or must be approved by the SEC.

Liberty feels that a CAM provides many benefits to both a LDC and the Commission. Section I.F of this report provides a detailed discussion of the many values of a CAM.

(6) Transactions with pipeline affiliate(s) (Columbia Gas Transmission (TCO) and Columbia Gulf (CGT)) are at arm's length in that CKY pays FERC tariff rates.

Arm's length is defined as the standard under which unrelated parties, each party acting in its own best interest, would negotiate and carry out a particular transaction (KRS 278.010 (25)). Transactions at a published tariff rate, where an affiliate is charged the same fee as an unrelated party, would fit this definition.

(7) CKY's gas-purchase contracts with gathering/processing affiliate – Columbia Natural Resources (CNR) – have analogs that were negotiated at arm's length.

As noted in Conclusion #6, if unrelated parties complete a transaction at a market rate, a similar transaction at similar rates by an affiliate would seem to meet an arm's length standard. CKY also states that the market-price transactions meet the requirements of the Securities and Exchange Commission (SEC) under the jurisdiction of the Public Utility Holding Company Act of 1935, and that CKY's purchases of gas from CNR are consistent with the SEC cost allocation methodologies applicable to CKY and NiSource affiliates.

d. Recommendations

(1) Columbia should emphasize the importance of maintaining an accurate method of recording time to eliminate possible month-end estimates, and should provide for more frequent review of the code pattern of time allocation. *(Conclusion #2)*

Recording time is one of the foundations of cost allocation. All employees should understand the importance of accurately recording time and how their time is charged and allocated to other companies and departments. Management and supervisory personnel should make a concerted effort to ensure their own and their employees' time records are maintained daily, rather than completed at month's-end. Management and supervisory employees should understand their own and their department's code pattern(s) for employee time, capital costs and all other shared costs, providing training to their employees as needed.

III. Company-by-Company Reports

C. Louisville Gas and Electric Company

1. Gas Supply Planning

a. Scope

This chapter of Liberty's report addresses the following aspects of the Louisville Gas and Electric Company's (*LG&E's*) gas supply planning practices:

- Integration with Corporate Plans
- Load Forecasting/Risk Analysis
- Balancing Supply Options/Capacity Portfolio Analysis
- Supply Planning Flexibility
- Impact of New Markets
- Monitoring of Key Assumptions and Plan Implementation
- Peak Period Performance

b. Background

(1) Integration with Corporate Plans

LG&E Energy Corporation, the parent of Louisville Gas and Electric Company, is a subsidiary of Powergen plc of the United Kingdom. Powergen was acquired by E.ON AG of Germany on July 1, 2002. E.ON's acquisition of Powergen was approved by the SEC in June 2002. LG&E Energy Corporation is headquartered in Louisville, Kentucky. LG&E's Gas Control and Gas Supply Departments are located at its Broadway Office Complex, also in Louisville. LG&E Energy owns and manages two regulated utility businesses in Kentucky, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company, along with several domestic and international unregulated energy interests. Of those entities, only LG&E provides natural gas sales and transportation services to its customers, and all gas operations are located in the Louisville area.

Chapter 2, Organization, Staffing and Controls provides a complete description of the organizational structure and responsibilities of the entities within LG&E involved in natural gas supply procurement and management.

With respect to planning functions, the Gas Supply Department (*Department*) leads the effort in developing the annual Gas Supply Plan, clearly described in LG&E's Bid Evaluation and Gas Supply Strategies document. Developing this Plan involves several processes that must be integrated to create a meaningful overall strategy. These processes include, but are not limited to, gathering regulatory information both at the state PSC and federal (FERC) level, collecting input related to investment planning, assessing desired modifications to the gas supply portfolio, determining company-owned storage operational, deliverability, and other issues, as well as reflecting PBR considerations. (Existence of the PBR mechanism is always a factor for LG&E as it considers the optimal strategy for a gas supply plan, and the balance of demand versus supply resources, that will result in savings by responding to PBR incentives.) Forecast information (including forecast sendout for sales customers as well as large customers and usage for electric generation) is provided by the Market Analysis Department. Because the economic and load forecasts from the Market Analysis Department are an important component of the plan, they are tested and evaluated by both Gas Control and the Gas Supply Departments before finally being incorporated into the plan.

After incorporation of operational, regulatory, credit, legal, marketing and other considerations as described above, the Gas Supply Plan is presented to Management for review and approval.

(2) Load Forecasting/Risk Analysis

As mentioned above, forecasting is initiated by the Market Analysis Department, and is reviewed by Gas Control and the Gas Supply Department to ensure that the formulas can be relied upon to accurately estimate short-term (daily and monthly), long-term (annual and five-year forecasts), and design-day load for each customer class, vis-à-vis historical and expected loads as well as other factors that can affect gas demand.

LG&E's forecasting procedures involve generation of an econometric model for each customer class and separate forecasts for each of the top 25 gas customers. The new forecast for the upcoming heating season is generated by August of each year. This forecast then becomes an important input for gas supply portfolio management and the subsequent development of an optimal portfolio.

LG&E's methodology for determining its forecasted sendout formulas was recently modified. Previously, separate equations were used to model demand for each month. Now one equation is generated incorporating all months of the year, with augmentation by dummy variables for handling the weekday/weekend variations. This procedure is conducted for determination of usage considering different weather scenarios. Regressions contain weather variables such as HDD, and truncated HDD variables, such as HDD20 and HDD30 (HDDs greater than 20 and 30, respectively) to capture non-linearity in sendout requirements as a function of ambient weather conditions.

LG&E's portfolio design conditions assume a combination of weather conditions (77 HDD on coldest day, and 70 and 65 HDD for the next two coldest days) as well as a peak-day reserve margin of 35,000 Mcf. The size of the reserve margin is based on a compressor unit outage that was actually experienced during January 1994 and a supply curtailment as the result of a supply freeze-off that occurred in December 1989. The failure of a key mechanical component (such as a compressor unit) or a supply failure could have a dramatic and adverse impact on service to customers.

There are no prohibitions relating to a maximum level of reliance on individual vendors or suppliers. LG&E strives to strike a balance between low price offerings and supplier diversity. Given similar price offerings, the Gas Supply Department opts for new suppliers to add diversity. This strategy has helped in motivating suppliers to compete more aggressively.

LG&E has five company-owned storage fields that it manages as a part of its gas supply portfolio. These fields are modeled using a Storage Withdrawal Forecast (SWF) model to ensure optimal deliverability throughout the heating season based on a design winter scenario for firm customers, excluding interruptible loads.

(3) Balancing Supply Options/Capacity Portfolio Analysis

LG&E uses two models in the development of an optimal gas supply portfolio. The gas supply optimization model, SENDOUT, is the principal model utilized, accompanied by use of the SWF model to manage storage deliverability. Both models are run several times throughout the year in order to aid in the development of different load scenarios being analyzed for various reasons. Storage deliverability is assessed throughout the heating season to ensure optimal deliverability. On an ongoing basis, forecasts provided by Market Analysis are evaluated against the gas supply portfolio to determine the optimal usage of gas resources.

The SENDOUT model is used for annual supply planning purposes, analyzing transportation requirements, and optimizing the use of storage, as well as verifying and testing other assumptions and results related to gas supply planning. Part of the value of the SWF model is that it covers considerations regarding storage constraints used in determining LG&E’s storage field withdrawal schedules that cannot be fully determined by SENDOUT.

LG&E does not have a retail customer choice program, and therefore the gas supply plan does not have to account for third-party suppliers in the mix of planning options. Firm pipeline transportation and storage contracts and company-owned storage capacity are allocated as necessary to meet the needs of its firm customers. Company-owned storage provides most of the necessary flexibility to meet varying demand. The total deliverability of the five company-owned storage fields is limited by various operational constraints, and the current total daily pipeline contract demand during the winter months is 253,900 MMBtu.

Liberty’s analysis of LG&E’s portfolio indicated that the current portfolio of resources is appropriate for its load forecast. Similarly, LG&E’s peak-day assumptions are consistent with extreme weather that has recently occurred in LG&E’s service territory. LG&E treats its FT transportation customers and G6/G7 interruptible rate classes separately from its firm load. Planning for design-day deliverability assumes that company-owned storage is solely used to meet firm demand.

(4) Supply Planning Flexibility

LG&E's selection of supply contracts incorporates supply planning flexibility in terms of supplier volume variability; most of the supply contracts allow for a limited number of changes to nominated volumes during the month. In addition to the flexibility incorporated into its various gas supply contracts, additional flexibility (within operating and contractual limitations) is available to LG&E through its on- and off-system storage.

(5) Impact of New Markets

LG&E indicates that residential customer additions are made within the current mandated extension rule requiring LG&E to provide customers with a free 100-foot main extension. At current rates, such an extension is uneconomic for attaching residential customers. Without the mandated 100-foot-free main-extension rule, LG&E would not likely extend service to new customers unless the customer's demand was large enough to justify the associated investment. Therefore, LG&E is not actively seeking any service expansion for residential customers. The situation regarding service under other rate schedules (such as CGS, IGS, G-6, G-7, or FT) may be different because these types of customers may consume more gas than residential customers, thus producing higher returns given the costs that LG&E incurs to provide service to them.

(6) Monitoring of Key Assumptions and Plan Implementation

LG&E prepares several documents that monitor plan implementation. These include reports to monitor quantities delivered by pipeline service and storage, comparisons of actual and daily calculated loads to evaluate forecasting accuracy, reports to track monthly gas supply costs, daily supply plans, and monthly purchase compositions. Internal memos describing monthly plans and actions contain detailed information regarding nomination dates and volumes and compliance with storage ratchets.

Throughout the year the Market Analysis Department, Gas Control and the Gas Supply Department interact and monitor actual performance versus the gas supply plan. Historical load information is used as a reference, and compared against ongoing performance of the gas supply portfolio. Key assumptions provided by other LG&E departments, including Operations, Regulatory, Credit, Legal and Marketing, are monitored, with the Gas Supply Department acting as the focal point for turning feedback from actual operations into the base for supply planning for the next period.

(7) Peak Period Performance

LG&E's peak performance during the winter of 2000-01 was successful. LG&E had an adequate portfolio to meet design-day demand and cold-weather conditions, including a reserve margin, the size of which is based upon the failure of a single compressor unit at one of its compressor stations. This reserve margin can be used to cover not only equipment failure, but also supply freeze-offs and forecast error.

c. Conclusions

(1) LG&E has good gas demand forecasting procedures.

LG&E's gas demand forecasting procedures are very thorough. The independent analysis of large customers and the use of economic variables to augment its demand forecast are both appropriate. LG&E generates its demand forecast using historical demand, economic and demographic forecasts, and price forecasts. The demand forecasts for each homogeneous class (such as residential, commercial, etc.) are done on a usage-per-customer basis. On the other hand, for large-volume industrial customers the forecast is done on an individual-customer basis.

At the time of Liberty's first-round interviews, LG&E's demand forecast used for gas supply planning consisted of separate sendout regressions, one for each month. In an attempt to capture and account for the skewness in the distribution of weather (as measured by heating degree-days, or HDD) in the Louisville area, LG&E added two cold-weather variables to its regression equations, one for the number of HDD above 20, and another for the number of HDD above 30. Since that time, LG&E has combined the monthly regressions into an annual equation, and has removed the cold-weather variables from the demand forecast equations.

Liberty had concerns about the approach used by LG&E at the time of the first-round interviews. Liberty's experience is that, while adding the two variables improves the "fit" of the regression equations, it introduces two biases. The first bias is due to the selection of extreme weather variables that go into the equation, and the second is due to the decision to run these equations for each calendar month as opposed to daily or seasonally.

These weather biases have since been eliminated by LG&E. The first bias was eliminated by removing the two cold weather variables from the demand forecast equations. The second bias was eliminated by combining the monthly equations into an annual equation.

LG&E uses a separate equation for design-day and extreme weather planning purposes that contains HDD and two cold-weather variables to improve the forecast of design-day sendout. In Liberty's experience, there is a better way to perform both the annual sendout and the peak-day sendout forecasts using a unified Monte Carlo methodology. Since the benefits of the method would need to be evaluated relative to the current methodology in terms of benefit to customers, Liberty is not recommending that LG&E adopt our preferred approach; rather, our approach remains an alternative preferred by us.

LG&E's supply plans are well integrated with corporate plans, and they are revised to plan for anticipated changes. The provided gas supply plan is thorough in analyzing all aspects of factors relating to procurement strategies.

(2) LG&E has commendable gas supply portfolio-planning procedures.

LG&E’s gas supply plan is well designed and selected to handle risks due to supplier reliance, pipeline reliance and weather conditions that may occur. LG&E’s design conditions assume a combination of weather conditions (77 HDD on coldest day, and 70 and 65 HDD for the next two coldest days) and include a reserve margin. LG&E’s design winter taken as a whole, and its use of the three design days as described above, are based on weather conditions and patterns recently experienced by LG&E and its customers. As such, LG&E’s use of a design winter ensures that adequate supplies will be available (delivered into its system via either on-system storage or interstate pipeline) to reliably serve the requirements of its firm customers. While these assumptions could be augmented with a cost-trade-off analysis, as suggested in Liberty’s general analysis on weather variation and requirements forecasting, presented in Section I of this report, LG&E’s methodology provides a margin of safety to minimize gas-supply risks that could impact LG&E’s ability to serve its high priority space-heating customers.

Liberty’s ROGM results for LG&E confirm the appropriateness of its resource portfolio, and indicate no significant resource surpluses. LG&E’s use of SENDOUT, its proprietary Storage Withdrawal Forecast (SWF) model for gas supply planning, and a neural-network-based model for short-term demand forecasting, constitute a solid framework for gas supply planning. Given LG&E’s various company-owned storage fields and their respective constraints, LG&E ensures with the SWF model that optimal storage deliverability is maintained throughout the storage withdrawal season, hence decreasing its reliance on more expensive alternatives such as NNS service from Texas Gas.

(3) LG&E’s approach to analysis of potential storage investments could be improved. *(Recommendation #1)*

LG&E’s 1995 management audit contained the following recommendation:

> Conduct a formal multi-phase review analyzing the potential costs, benefits, and alternative funding approaches to expand both the operational flexibility and physical capability of the existing storage fields, and/or other alternatives to reduce the need for future pipeline capacity increases.

The Company reports that it identified “conceptual storage enhancements”, but that it did not perform “costly and comprehensive engineering analyses of specific storage deliverability projects.” Rather, as a part of its filing requesting an extension of its Performance-Based Rate-making (PBR) mechanism, the Company proposed an alternative approach for recovering costs associated with the development of storage deliverability when the Company’s analysis suggested that a specific storage enhancement project would be more economic than a commensurate amount of pipeline capacity. The Company proposed the recovery of the revenue requirement for approved storage projects through its Gas Supply Clause (GSC) mechanism until the succeeding rate case, rather than waiting for that rate case to begin recovery of those costs.

The Commission rejected LG&E's proposal. The Commission provided instead that storage development projects, approved by the Commission pursuant to the procedures proposed by LG&E, would be treated as regulatory assets between rate cases, so that all of the Company's costs, including carrying costs on investments in the approved projects, would be eligible for recovery through base rates, beginning at the effective date of its next rate case.

LG&E reports that it has now incorporated the rate treatment approved by the Commission into its capacity planning and capital budgeting processes. The Company described its planning process for potential storage development projects in its Management Audit Action Plan Progress Report, dated January 7, 2002. That process can be summarized as follows:

1. LG&E will perform conceptual engineering studies and analyses to develop potential storage development projects. Such projects might include additional purification or compression, the drilling of additional wells, the deepening of existing wells, or the drilling of horizontal wells and "other additions to infrastructure and facilities".

2. Next, LG&E will estimate the amount of Texas Gas No-Notice Service that could be displaced by each potential project.

3. LG&E will then compare, project by project, on a net-present-value (NPV) basis, the cost of each storage project with the cost of the potentially-displaced NNS service.

4. For those projects that appear to be more economic than the corresponding amount of NNS, giving consideration to the Commission's approved cost-recovery treatment (treatment as a regulatory asset until the subsequent rate case), LG&E would perform a detailed engineering analysis to verify each project's feasibility through cost estimates with meaningful confidence levels. At this stage, LG&E would also update the NPV and other associated analyses to reflect the costs determined from the engineering analyses.

5. For those projects that still appear attractive after the cost-refinement step above, LG&E would file with the Commission for approval. The application for approval would report the results of the engineering and economic evaluation, and would request establishment of a project-specific regulatory asset account.

This process is similar to the one suggested by LG&E as part of its proposal for alternative rate treatment. LG&E advises that, under the rate treatment approved by the Commission, LG&E would proceed through Step 4 (which includes a detailed engineering analysis and updated NPV analysis) only if the project compared favorably with the Company's other capital projects. If the project competed successfully with other capital projects, and if it survived the engineering and NPV analysis, the Company would file with the Commission for approval. LG&E would commence construction only after the Commission had approved the projects based on the NPV analysis using the engineering estimates.

Liberty is concerned that this process may not accurately reflect the costs and benefits of LG&E's potential on-system storage projects because it does not include the impact of storage development projects on the cost to establish a reserve margin. The 1995 management audit reported that, following a compressor engine failure that occurred during a cold spell in January 1994, LG&E reduced the planned design-day withdrawal rate of one of its storage fields (Muldraugh) as a reserve margin. The size of the reserve margin was based on the failure of a single compressor unit, but the reserve margin could also be used to prevent supply disruptions to customers in the event of mechanical or other failures, supply freeze-offs, forecasting error, as well as other contingencies. That reduction required other supply resources to be available in order to be able to meet design-day loads. At the time of the management audit, LG&E was making up the difference with a combination of (a) buying at a higher load factor in November and December under existing contracts on Texas Gas, in order to retain stored gas longer, and (b) buying back-haul supply on Texas Gas for the month of January.

Liberty's view is that any extra costs associated with providing this reserve margin should be assessed against LG&E's on-system storage options in comparing them to options involving pipeline supply. In Liberty's experience, design criteria for pipeline systems include the possibility of equipment failure, and the pipeline companies install a certain amount of redundant equipment to minimize or eliminate the possibility that their service will be affected by such failure. The costs of that extra equipment are in the pipelines' rates. Thus, any reserve margin against the possibility of pipeline service failure is unnecessary. Appropriately, LG&E's reserve margin is not designed to address such a pipeline service failure.

The failure of a particular piece of equipment in a smaller, machinery-dependent system is a real possibility, however, as LG&E learned in 1994. (In fact, LG&E reports that, in February 1996, more than one compressor unit was down for part of a day.) The other Kentucky LDCs that have on-system storage do not use reserve margins, but their storage systems do not depend on compression to deliver stored volumes to load centers on a peak day. Thus, we understand LG&E's decision to plan for less supply on a peak day than its on-system storage facilities are normally capable of providing. Our concern is that this consideration, and the costs of dealing with it, be reflected in LG&E's economic comparisons between on-system storage options and pipeline-supply options.

LG&E reports that the required reserve margin would not change if other storage development projects were implemented. Furthermore, LG&E reports that the required reserve margin would be the same with or without a new project. However, further storage development may change the way in which the reserve margin is created. In the event that the reserve margin did not change as the result of a new storage project, no reserve-margin cost should be reflected in the cost of that project. If a particular project would increase the reserve-margin requirement, however, then the incremental reserve-margin costs should be added to the costs of that project in order to have a fair evaluation of the project against the pipeline capacity alternative. Alternatively, if a particular project would reduce the cost of the reserve-margin requirement, that project should be credited with any tangible benefit of that reduction.

d. Recommendation

(1) LG&E should report to the Commission on the results of its conceptual studies of potential storage development projects. *(Conclusion #3)*

Liberty recommends that the Company undertake a two-part study of potential storage development projects and report on those studies through the Management Audit Action Plan (MAAP) process as a part of the follow-up to this gas procurement audit.

The recommended report on development of storage projects should have two parts. The first part should address the reserve-margin requirement built into the Company's design-day planning. As noted in Conclusion #3 above, at the time of the 1995 management audit, that requirement was being met by a) increased purchases under existing contracts during the months of November and December, and b) a back-haul supply for the month of January. The recommended section of the report should address the level of the reserve requirement, how it is being met at the time that the report is prepared and what feasible alternatives may exist to meet the requirement. If the problem is the risk of a compressor unit failure, for example, perhaps it could be resolved by installing and maintaining an extra unit. Another question is whether loss of a compressor unit for an entire day is the appropriate criterion for determining the size of the reserve margin. This part of the recommended report section should both identify alternatives that are technically sufficient solutions to the problem that gives rise to the reserve requirement, and demonstrate that the alternative being used is the most cost-effective one. (The 1995 Management Audit Report also recommended an analysis of alternative approaches to meeting the reserve-margin requirement. See p. 500.)

The second part of this report should present LG&E's most attractive potential storage development projects. Liberty expects that these projects will be developed through Step 3 of the evaluation process detailed in LG&E's 1995 Management Audit Action Plan Progress Report on Item XII-R1 (and summarized in Conclusion 3, above); that is, through comparison, project by project, on a net-present-value basis, of the cost of each project with the cost of alternative NNS service. As discussed in Conclusion 3, if any project affects LG&E's reserve-margin requirement, then that project should be charged with any incremental reserve-margin costs that it causes, or credited with any reserve-margin savings that it provides.

If some projects have made it through Step 4, Liberty understands that those projects will have been presented to the Commission for approval. Thus, the projects to be discussed in the report section that we are recommending are ones that are attractive on the basis of the net-present-value analysis (Step 3), but have not yet been successful in securing the required capital funding.

In general, Liberty finds that capital constraints in a public-utility setting are a good thing. In our experience, rate-base/rate-of-return regulation brings with it a tendency to over invest in utility plant. This tendency can be exacerbated in a performance-based-ratemaking (PBR) environment, where spare capacity offers the opportunity for extra revenues with little risk to the company's shareholders. In those circumstances, limits imposed on that tendency by a requirement to compete for investment capital are in customers' interests. Moreover, in LG&E's

case, other investment priorities, such as the Company's large-scale main replacement program, and the Company's current gas-main-extension policy, may appropriately require other attractive investments to wait. Therefore, because of the capital constraints under which LG&E's gas business operates, it's possible that performing analyses of the storage development projects will not necessarily mean that they will compete successfully with other LG&E capital projects.

Liberty is concerned that on-system storage development not be unreasonably restricted, however. Liberty observes that, while conceptual studies and net-present-value comparisons -- Steps 1 through 3 of the project-evaluation process – are generally done with in-house resources, the "detailed engineering analysis" required to verify cost and performance characteristics (Step 4) often involve significant expenditures for outside experts.

The costs of in-house resources are generally covered by allowances in base rates. Expenditures on engineering evaluations, however, are often the first expenditures associated with capital projects to be capitalized and recovered as investments in rate base. Expenditures on outside engineering may have a somewhat high risk of non-recovery, as it is possible that the results of the engineering analysis will not be favorable, and that the project will be abandoned. The Commission's determination regarding the treatment of project expenditures refers to regulatory-asset treatment for "projects that pass [the Commission's] review"; it could be that expenditures on projects that fail their engineering evaluations would not be eligible for recovery.

As part of the report section recommended here, Liberty suggests that an estimate of the cost of the required engineering evaluation be provided for each potential storage development project addressed in the report. If it appears that otherwise-worthy projects are not being pursued because of the risk of loss of expenditures on engineering evaluations, then Liberty would recommend that the Commission consider regulatory-asset treatment for those engineering evaluation expenditures, just as for the storage development projects themselves. This treatment should be provided, if at all, on a case-by-case basis, and only for those projects for which the LDC has requested such treatment and for which the NPV analysis demonstrates benefits for customers.

Liberty observes that the Company has received the Commission's approval to offer storage-related services, as well as sales of stored gas, as part of its off-system sales program. Under the Company's PBR plan, the Company receives 25% of the proceeds from off-system sales in excess of a benchmark amount, with the remaining 75% returned to sales customers. Liberty feels it is important that LG&E's potential storage development projects be considered by interested parties, as well as the Commission, on a project-by-project basis.

2. Organization, Staffing and Controls

a. Scope

This chapter of Liberty's report addresses the aspects of Louisville Gas and Electric Company's (LG&E) management and operations that relate to its overall organization, staffing and controls:

- Organizational Structure.
- Staffing.
- Approval Authorities.
- Work Process Definition and Control.
- Documentation Requirements.
- Auditing.

b. Background

(1) Organizational Structure & Staffing

Natural gas supply planning, procurement and management for LG&E is handled by the Gas Supply Department (Department) of LG&E. The Department is managed by the Director, Gas Management Planning & Supply, located in Louisville, Kentucky. The five person Department, including the Director, is responsible for the development of all gas supply and system management strategies and the procurement of all natural gas and pipeline transportation services required to reliably deliver adequate quantities of natural gas to LG&E. In summary, the responsibilities of this Department are:

- Gas Supply Planning
- Gas and Transportation Procurement
- Federal and State Regulatory Activity
- End-Use Transportation Coordination

The Department buys gas for the electric generation side of LG&E's business only for facilities within the LG&E system (behind the distribution system), and transfers the cost to these facilities on a weighted average cost of gas basis. There is an exception to this with the Paddy's Run Unit 13, where the gas price is transferred at actual cost associated with each discrete transaction made on behalf of Paddy's Run Unit 13. The Department does not buy gas for activities of the merged sister company, Kentucky Utilities Company (KU). Gas procurement for these KU electric generating facilities is done by a completely separate gas supply group that has limited interaction with the Gas Supply Department.

The Director of the Gas Supply Department reports to the Senior Vice President – Distribution Operations, LG&E Energy Services Company, who in turn reports to the CEO of LG&E Energy.

The Gas Supply Department works closely with two other departments in LG&E Energy Services Company, the Gas Control & Storage Department, and the Market Analysis Department. The Gas Control & Storage Department consists of a Director, Distribution Operations, and his support staff of four individuals who handle the gas storage and gas control operations, and provide geological support. Gas Control operates 7 days per week, 24 hours per day. The Gas Control Department is responsible for the daily operation of LG&E's gas control function by monitoring, balancing, and controlling of gas supply deliveries across the systems to ensure that the systems are performing in a safe and reliable manner. Gas Control operates within the framework of LG&E's pipeline transportation and storage agreements and also provides storage management of the five separate storage fields owned and operated by LG&E. Gas Control ensures proper levels of inventories are maintained in order to provide the expected deliverability when required. The Director reports to the Senior Vice President – Distribution Operations, LG&E Energy Services Company.

The Market Analysis Department is directed by a Manager, Market Analysis, who supervises a team of 8 analysts. The Department is responsible for the forecasting, load research and other market analysis needs of the gas and electric businesses of LG&E. The Department also coordinates its market analysis with other internal groups at LG&E to ensure support of long-term strategic plans and initiatives. The Manager of this Department reports to the Director, Market Analysis & Valuation, who in turn reports to the Senior Vice President for Energy Marketing. This Senior VP reports to the Senior Vice President for LG&E Energy Services Company. The Director and the two Senior VPs are involved primarily in work on the electric side of LG&E's and KU's energy business.

Performance Measurement

The Gas Supply Department has a comprehensive performance measurement system for its employees. Annually, the Director of the Department meets with his employees individually in a process that mutually establishes goals and objectives for the coming year. The Director reviews the performance of his people at least twice each year, with the mid-year evaluation being less formal.

The annual process is formalized, and includes a management by objectives (MBO) process wherein each employee and the Director agree on goals and objectives for the next year, and then performance during the year is measured against these 4 to 6 objectives. At the end of the year, each employee writes up his own self-assessment of his own performance; this is compared to the Director's evaluation, and discussed.

There are two components to compensation, resulting from the annual evaluations. The first piece is an annual salary adjustment that will vary based upon an employee's performance and position within his pay range. It is basically a cost of living increase.

The second piece is called the Team Incentive Award, and consists of three factors. The first factor is Internal Operating Profit applicable to LG&E Energy's utility operations, which is pre-tax profit after deducting interest expense and preferred dividends. The second factor is external customer satisfaction. This factor is measured by a survey administered by an outside third party. This external survey is conducted monthly and LG&E is compared to peer utilities by this third party external survey organization. The third factor is the real individual incentive component and is called the Individual Effectiveness (IE) rating. Employees are measured against factors agreed upon with each of them, such as whether or not they have added more suppliers to the spot list of suppliers, and their own ability to manage pipeline services, the accuracy with which they manage pipeline services, etc. Underlying all of this is the individual incentive to get promoted. In this Department, promotion will not occur solely on the basis of time in position. Most people desire promotion, and so this factor motivates them to do well on their performance evaluations. While not a direct factor in the IE, the price of natural gas is included inherently within a number of the other IE components.

Also, part of the goals and objectives setting process for employees is the Individual Development Plan (IDP). Each employee sets goals for himself that are more personal in nature related to his own career development, such as management development courses. This provides employees the opportunity to guide their career development.

Training

The Department has an organized training program. A significant part of the training is cross-training, and in fact, part of the process of setting goals and objectives for each individual during the performance measurement process includes a cross-training component. The two individuals in the Department who are relatively new to the organization are a current focus for training.

The underlying philosophy behind training in the Department is ongoing emphasis on having employees take responsibility and ownership of their gas procurement activities. In addition, employees are evaluated on how they assume this responsibility. Finally, an objective of training is to stress provision of natural gas reliably, and to provide it at the cheapest possible cost for the LG&E customers.

In addition to internal training, some of which is personally led by the Director, the Department also sends people to appropriate gas industry seminars.

Job Descriptions

Job descriptions for employees of the Department are current, and appropriately describe the activities and responsibilities for each of the Department's positions. Job descriptions are used to some extent in the performance measurement process, but as indicated above, the primary factors in measurement of performance are the goals and objectives.

The Director is careful to manage the positions within the Department in a way that maximizes the capabilities of individuals, and that can be supported through analysis of job descriptions and budgetary targets. Any changes to the personnel count must fit into the Department budget, and must also be approved by the Senior Vice President – Distribution Operations, LG&E Energy Services Company. Since 1986 when this Department started with only one position involved in gas procurement operations, the Department has been carefully "grown" to ensure that each new position could be justified. The result has been a stable Department, and one that has not experienced the loss of any positions in a time of significant downsizing and change throughout the greater LG&E organization.

(2) Approval Authorities

Approval of activities within the Gas Supply Department are controlled by a formal LG&E decision matrix, or chart of approval authorities, that specifies the magnitude of commitment that various levels of management can make. These limits are specified in the LG&E Corporate Policy titled "Engagement Authority Limits". This applies to procurement decisions, as well as preparation and approval of the annual gas supply plan.

Preparation of the gas supply plan is guided by a formal flow chart detailing the necessary processes involved in its preparation and in conjunction the Director regularly solicits and receives input from other departments, such as operations, regulatory affairs, credit, legal and marketing. The Director works very closely with each of these groups, and they provide input to the annual gas plan, but these groups do not formally sign off on the plan. There is an annual assessment of the gas plan conducted by the Director and his staff, and each year the plan is submitted to the Senior Vice President – Distribution Operations, LG&E Energy Services Company, for approval. The plan is finally endorsed by the CEO of LG&E Energy.

(3) Work Process Definition and Control

The operations of the Gas Supply Department are guided by formalized, written policies and procedures that are current. Procedures have been in existence since the Department was first formed in 1986. The procedures used by the Department are lengthy and detailed, and are kept up to date as necessary by the four staff members. The philosophy behind these procedures is that the people using them have written them. The procedures are written with enough flexibility to provide guidance and to allow operation without being unduly restrictive.

LG&E has a detailed Cost Allocation Manual (CAM) specifying methods of handling costs for shared services and properly allocating them within the Company.

The Gas Supply Department does not have any dealings with any affiliates and so it is not necessary to have any procedures related to affiliate relations.

Risk Management activities at LG&E are overseen by a senior level Risk Management Committee that governs all risk-related LG&E operations. Currently, LG&E has a risk management policy in draft form that covers the use of financial hedging instruments as contemplated under the Company's hedging program filed with the Commission in August 2001. Inasmuch as LG&E has not received Commission approval to implement a natural gas hedging program that would require the use of financial hedging instruments, the applicable risk management procedures have not required finalization. The current draft policy will provide an appropriate foundation for a set of finalized procedures in the event that the Company files and receives approval of a natural gas hedging program that requires the use of financial hedging instruments. In its draft form, this policy contains the essential ingredients normally found in risk management plans.

(4) Documentation Requirements

Documentation of gas procurement and supply management activities within the Gas Supply Department is satisfactory. Upper management is kept advised of activities in the Department through three different reports submitted on a monthly basis. These reports relate to gas costs by component, to PBR information, and to comparisons of LG&E costs with those of other utilities. While this is important information for senior management, the reports could be improved through simplification and inclusion of a frame of reference so that management will be able to easily determine how the data in the current reports relates to prior periods, or to budgets, for example. In addition, inclusion of graphical presentations would improve the transmission of this information.

The Director of the Gas Supply Department uses his regular meetings with the Senior Vice President – Distribution Operations, LG&E Energy Services Company as an important part of information exchange. He meets with the Senior VP every two to three weeks as part of the regular meetings between all of the Directors of Distribution Operations, and in addition, the Director has his own one-on-one meeting with the Senior VP every two weeks. The Director has his own internal staff meeting every week. In addition, top management is kept informed of the activities of the Gas Supply Department through their review and approval of the Gas Supply Plan, as discussed in Section (2) above, Approval Authorities.

Overall guidance for the LG&E procurement process comes from the annual Strategic Planning Process. While the Gas Supply Department is responsible for developing and implementing this Strategic Plan (*Gas Supply Plan*), input is obtained from several areas of the Company to ensure that this plan incorporates all of the necessary elements of the overall LG&E corporate strategy. In particular, operational, regulatory, credit, legal and marketing initiatives and issues are considered in the development of the Gas Supply Plan. Each year, the Gas Supply Plan and the accompanying bid evaluation process and contracts resulting therefrom, are presented to Management for review and approval.

Not only is the Gas Supply Plan prepared in detail, but the process for preparing it is described in considerable detail, with accompanying flow charts and process descriptions so that it is completely clear how the process works, and what elements are to be considered in formulating this plan. The goals and objectives central to the plan consider a comprehensive list of both internal and external factors. Detailed discussion of the gas supply planning process is included in Section I of this report, Task Area One – Gas Supply Planning.

(5) Auditing

Historically, LG&E Internal Auditing has conducted audits of gas procurement and of fuel procurement for electric generation in alternating years. However, whenever LG&E Energy's Internal Auditing Department conducts an audit of gas procurement, LG&E Energy's external auditors conduct an audit of fuel procurement for electric generation. In the next year, these roles have been reversed. The results of these audits over the last few years have not resulted in findings of any material discrepancies related to the operations of the Gas Supply Department.

The cycle of when internal audits are conducted, and what issues to investigate, is continually reviewed based on a comprehensive risk assessment analysis. There are many components to this analysis including a review of past internal audit findings, input from senior management as to particular issues that might be of concern to them, quarterly risk assessment evaluations by the Gas Supply Department, consultation with external auditors, and overall assessments by the Internal Audit Department of those areas of corporate operations presenting risk exposure to the corporation.

LG&E has indicated that the results of their comprehensive risk assessment analyses indicate that the cycle of conducting internal audits of the Gas Supply Department might be lengthened. Currently, some consideration is being given to increasing the audit cycle for internal audits to once every 3 to 5 years. In addition, LG&E has indicated that with current limits on auditing resources, lengthening the audit cycle to every 3 to 5 years appears reasonable to LG&E. Considering the sophisticated risk assessment analysis associated with any decision to increase the period between audits, this appears to be reasonable.

c. Conclusions

(1) Reports sent to upper management by the Gas Supply Department could be improved. (*Recommendation #1*)

Upper management is kept advised of activities in the Department through three different reports submitted on a monthly basis. These reports relate to gas costs by component, to PBR information, and to comparisons of LG&E costs with those of other utilities. While this is important information for senior management, the reports could be improved through simplification and inclusion of a frame of reference so that management will be able to more easily determine how the data in the current reports relates to prior periods, or to budgets, for example. Information in these reports is detailed and difficult to read (numbers only). In addition, inclusion of graphical presentations would improve the transmission of this information.

(2) The Gas Supply Department has done a good job of documenting the policies and procedures related to procurement and management of natural gas supplies.

The operations of the Gas Supply Department are guided by formalized, written policies and procedures that are current. Procedures used by the Department are lengthy and detailed, and are kept up-to-date as necessary by the four staff members.

(3) Operations of the Gas Supply Department are guided by a comprehensive Strategic Plan (Gas Supply Plan).

The Gas Supply Department engages in an annual planning process that incorporates important internal and external parameters and results in a very detailed and complete Gas Supply Plan. The plan provides guidance for operations throughout the year, and is approved by senior management each year. Not only is the plan complete, but LG&E's processes are documented in detailed procedures, process descriptions and flow charts to ensure that consistency is maintained from year to year, and that all necessary factors are considered in preparation of the plan.

(4) Job descriptions for positions in the Gas Supply Department are current and effectively describe the positions to which they apply.

Job descriptions for employees of the Department are current, and appropriately describe the activities and responsibilities for each of the Department's positions.

(5) The Gas Supply Department has appropriately recognized the importance of training programs.

The Department has an organized training program. It is designed to orient individuals in the Department who are relatively new to the organization. A significant part of the training is cross-training, and in fact, part of the process of setting goals and objectives for each individual during the performance measurement process includes a cross-training component.

The underlying philosophy behind training in the Department is ongoing emphasis on having employees take responsibility and ownership of their gas procurement activities. In addition, employees are evaluated on how they assume this responsibility. Finally, an objective of training is to stress provision of natural gas reliably, and at the cheapest possible cost for the LG&E customers.

(6) LG&E is efficient and effective in its planning, procurement and management of natural gas supplies.

The LG&E gas planning, procurement and management functions are organized in an appropriate fashion in order to accomplish efficient and effective procurement and management of significant quantities of natural gas supplies. LG&E is able to effectively manage its on-system storage, and its relations with interstate pipelines with a relatively small group of individuals, considering the quantities of natural gas procured and managed and the number of customers served.

(7) LG&E's program for internal auditing is guided by an appropriate and comprehensive risk assessment process.

On a regular basis, LG&E conducts a comprehensive risk assessment analysis of the operations of the Company, including the operations of the Gas Supply Department. The results of this process determine the cycle of when internal audits are conducted, and what issues to investigate. There are many components to this analysis including a review of past internal audit findings, input from senior management as to particular issues that might be of concern to them, quarterly risk assessment evaluations by the Gas Supply Department, consultation with external auditors, and overall assessments by the Internal Audit Department of those areas of corporate operations presenting risk exposure to the corporation.

LG&E has indicated that the results of this comprehensive risk assessment analyses indicate that the cycle of conducting internal audits of the Gas Supply Department might be lengthened. Currently, some consideration is being given to increasing the audit cycle for internal audits to once every 3 to 5 years. In addition, LG&E has indicated that with current limits on auditing resources, lengthening the audit cycle to every 3 to 5 years appears reasonable to LG&E. Considering the sophisticated risk assessment analysis associated with any decision to increase the period between audits, this appears to be reasonable.

d. Recommendations

(1) Improve the formatting of reports sent to senior management by the Gas Supply Department. (*Conclusion #1*)

In the dynamic environment of the energy business, it is crucial to have appropriate management and decision-making information.

Reports sent to senior management should be easy to read, and easy for the reader to put the report contents into the proper perspective. Reports must support analysis and strategy and contain information that is relevant to the identification of important issues in order to support effective decision-making. In order to accomplish this, reports should include a frame of reference so that management will be able to more easily determine how the data in the current reports relates to prior periods, or to budgets, as well as to projections of this information into the future. In addition, inclusion of graphical presentations would improve the transmission of this information.

3. Gas Supply Management

a. Scope

This chapter addresses LG&E's management of its gas supply. Topics addressed include the following:

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Renegotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management

b. Background

(1) Existing Gas Supply Portfolio

LG&E's principal relationship for pipeline capacity has been with Texas Gas Transmission Corporation. In the Order 636 implementation process, LG&E negotiated staggered contracts with Texas Gas, with contracts expiring in 1995, 1998 and 2001. Those contracts were extended in five-year increments, so the first ones have expired, and have been renewed again. The contracts that were scheduled to expire in 2003 have already been renewed, as LG&E needed additional capacity.

Connections to Tennessee Gas Pipeline were added in 1996. LG&E had a minor connection to Tennessee until late 1966, but that was abandoned due to unfavorable tariff provisions. Subsequent studies of connecting to Tennessee foundered for a number of reasons. In the aftermath of Order 636, however, arrangements for establishing the necessary interconnections were made.

Table 3.1, on the next page, summarizes LG&E's contracts with the pipelines.

Table 3.1 Transportation & Storage Capacity

Transporter:	**Texas Gas Transmission**					**Tennessee Gas Pipeline**
Rate:	**NNS**			**FT**	**STF****	**FT-A**
	Flowing Gas	Storage	2-Day/10% *			
Jan	147,000	37,900	18,490	18,000	29,000	51,000
Feb	147,000	37,900	18,490	18,000		51,000
Mar	147,000	37,900	18,490	18,000		51,000
Apr	60,000	18,950	18,490	54,000		51,000
May	60,000	-	18,490	54,000		51,000
Jun	60,000	-	18,490	54,000		51,000
Jul	60,000	-	18,490	54,000		51,000
Aug	60,000	-	18,490	54,000		51,000
Sep	60,000	-	18,490	54,000		51,000
Oct	72,000	26,530	18,490	54,000		51,000
Nov	147,000	37,900	18,490	18,000		51,000
Dec	147,000	37,900	18,490	18,000		51,000
SCQ - Winter	22,500,000					
SCQ - Summer	5,700,000					

* Except during the shoulder months of April and October, the "2-Day/10%" cushion volumes are not additive ot the total NNS contract demand.
** Note: Jan '01 Only

All volumes MMBtu/Day except SCQ

LG&E also has five on-system storage fields, all five of which are in Kentucky, with a portion of one extending under the Ohio River into Indiana. LG&E cycles about 12.5 Bcf through its storage fields annually, which amounts to just under 35 percent of its annual supply for sales-service customers. Deliveries from LG&E's storage account for 57 percent of peak-day deliveries to firm sales customers, however.

LG&E does not have any peaking facilities other than the storage facilities, pipeline transportation services and gas supply agreements. Specifically, LG&E does not have any LNG or other peak shaving facilities. LG&E does use a contract peaking service. This requirement is bid annually.

Coming out of the Order 636 process, LG&E created a portfolio of gas supply commodity agreements expiring uniformly over a five-year period. To get the process started, LG&E initially let contracts for one, two, three, four and five years in order to commence the contracting process in an orderly fashion.

Through its contracting activities and analysis of prevailing market conditions, LG&E found that there was little incremental benefit associated with longer-term contracts for gas supplies at market clearing prices with respect to pricing provisions and required flexibility. As a consequence of this experience, LG&E's commodity contracts have become shorter. In fact, there has been some observable evolution in operating conditions under the contracts.

(2) Supplier Identification and Qualification

LG&E is continually looking for new suppliers, as the Company is concerned about the declining numbers of suppliers. Typically, a supplier will contact the Company regarding its interest in being considered. After appropriate reference and credit checks, the Company enters into a base form of agreement for purchase and sale with a candidate supplier. After that, the new supplier is notified of the Company's requirements for supply, and invited to submit proposals.

A new supplier is used for spot-market supplies first, in order that LG&E might observe its performance. The Company's qualified suppliers list for 2000 and 2001 for short-term/spot requirements included 24 firms. LG&E uses its base form of agreement for purchase and sale, as most of the Company's off-system sales activity involves selling to the same companies that the Company buys from.

The procedures used by LG&E for supplier identification and qualification are very thorough and documented in considerable detail. LG&E's procedures provide detailed guidance for evaluating supplier reliability. LG&E realizes that without the secure supply provided by a reliable supplier, flexibility and price become meaningless. Thus, supplier evaluations focus on three specific components of reliability, which are flexibility, integrity and viability.

(3) Identification of Acquisition Needs

LG&E has been adding about 5,000 gas customers per year. This growth primarily impacts supply planning in the area of peak-load planning. Since pipeline and on-system deliverabilities are fixed, at least in the short run, the year-to-year increases in capacity needs have been met through adjusting the Company's requirements for peaking service.

There is an opportunity to increase the amount of pipeline capacity under contract at each contract's expiration. As noted above, some of the Company's contracts come up for renewal periodically. In fact, the Texas Gas contract that was due for expiration in 2003 was extended in advance of that date, as a part of LG&E's comprehensive review of pipeline and deliverability requirements.

Gas Supply and Gas Control conduct an annual supply planning process that is well supported through extensive policies and procedures. These procedures contain flow charts describing LG&E's gas supply planning and annual procurement processes and how the important elements of planning are linked to the actual procurement process. While Gas Supply is responsible for developing and implementing the plan and the procurement, the input of several areas within the Company is incorporated into the process to ensure that the final plan comports with LG&E's corporate strategy.

Identification of acquisition needs flows from Sendout Load Formulas provided by the Market Analysis Department. Based on the reports generated by the Sendout Model, Gas Supply's procurement experience, and Gas Control's operational experience, Gas Supply determines the new supplies and transportation services that are required for the planning period. In order to obtain those supplies or transportation services, Gas Supply develops bid specifications, and uses a formalized bidding process. This entire process is well documented in LG&E's written procedures.

Gas Supply conducts solicitations for each one of the LG&E natural gas supply requirements. One or more of the Gas Supply Specialists in the Gas Supply Department conducts, analyzes and documents the results of each solicitation.

(4) Negotiation and Renegotiation of Contracts

Prior to implementation of Order 636, LG&E did a very comprehensive analysis of its requirements for pipeline capacity, and of its objectives for its relationships with the pipelines and with gas suppliers. That analysis built on the Gas Supply group's experience in taking the gas-supply function from complete dependence on the pipelines (prior to Order 436, issued in late 1985), through a very aggressive spot-market program during the early 1990s. Out of that analysis came not only a set of strategies for dealing with its principal pipeline supplier, Texas Gas, but also guidelines for its gas-supply portfolio.

The Company's work on its contracts since then has been in the nature of adjusting its capacity contracts as it is able to improve the fit between the capacity portfolio and its load, adding a new pipeline connection, and responding to developments in contracting for gas supplies. In the area of gas-supply contracting, the Company has experimented with possible changes as it observed and learned of developments in the terms and conditions of those contracts. The strategies that the Company initially adopted provided for periodic contract expirations of contracts for both capacity and commodity, and negotiations over the renewal of the expired contracts have provided occasions where the necessary adjustments could be made.

(5) Contract Terms and Conditions

LG&E's contracts for transmission and storage capacity typically are service agreements under FERC Gas Tariffs, so the terms of those contracts are largely fixed by the FERC. There is some opportunity to negotiate over terms and conditions in the conduct of pipeline rate cases, however, and LG&E takes advantage of those opportunities by having a clear sense of its objectives each time that it enters such negotiations.

The Company has developed its own contract for term gas supplies, which includes lengthy provisions for adjusting rates of take. These provisions were initially built into the contracts to accommodate changes in the Company's load. More recently, those same provisions have been used to adjust takes in response to changes in the relationship between daily and monthly prices.

LG&E also has developed its own contract for replacement shippers when capacity is released. Rather than relying exclusively on the pipelines' electronic bulletin board procedures, the Company felt that it needed its own contract to ensure that contractual privity is established and payment could be ensured.

All of LG&E's form contracts are reviewed by outside counsel.

(6) Peak Period Performance

As noted in Chapter 1, Gas Supply Planning, LG&E has, since 1994, used a reserve margin to protect against a loss of deliverability. This margin was motivated by LG&E's experience of losing a storage compressor unit during the January 1994 cold spell. LG&E also revised its design criterion for the peak day after that winter.

As noted earlier in this report, the winter of '00/'01 was characterized by extended periods of colder-than-normal weather during November and December. However, this winter did not have extreme peaks, such as had been the case in the winter of 1994. Thus, from an operations perspective, '00/'01 was a successful one for LG&E.

The nature of LG&E's storage is such that it must be completely cycled annually. The Company's Tennessee capacity is full year-round, as it is connected to some low-cost sources of gas. Thus, LG&E "swings" on its Texas Gas contracts; in a warm year, it will not take as much gas on them, but in a year like '00/'01, it uses those contracts more fully. LG&E experienced no delivery failures during that winter, so the principal difference observed by LG&E during the winter of '00/'01, other than higher prices for natural gas, was a higher load factor on its Texas Gas contracts.

(7) Price Risk Management

A significant portion of LG&E's customers' winter-period requirements is delivered from its own on-system storage. Also, a portion of its winter requirements is delivered from the storage component of it Texas Gas No-Notice Service. Because the gas injected into LG&E's on-system storage as well as the storage component of Texas Gas's No-Notice Service is bought during the non-heating season, stored volumes of gas provide a considerable hedge against potential winter-period price increases.

After the Commission's July 17, 2001 Order in Administrative Case No. 384, LG&E also developed and proposed a price-mitigation program based on the purchase of call options. LG&E would have used funds from an approved Price Stabilization Fund to purchase the options for a portion of the gas to be delivered from interstate pipeline during the Hedge Period. On October 5, 2001, the Commission rejected LG&E's plan, as gas prices had fallen considerably by that time.

LG&E has policies and procedures in place to deal with credit risk, loss-of-market risk and regulatory risk. The Company also has an Authority Matrix that sets limits on the size of transactions that can be entered into on behalf of the Company by specific individuals. To date, however, because no hedge plan has been approved or is in place, the Company does not have finalized hedging risk-management policies and procedures that relate to LG&E's purchases of natural gas for sale to customers.

c. Conclusions

Context: According to data furnished by LG&E, the Company's residential gas prices have long been below averages for the U. S. and for the Commonwealth of Kentucky. According to GCA data on file with the Commission, LG&E's gas costs are also among the lowest in the Commonwealth, if not the lowest. It is in that context that these conclusions are offered.

(1) LG&E continues to be effective in dealing with its pipelines.

The 1995 Management Audit Report noted LG&E's effectiveness in dealing with its pipeline, which was only Texas Gas at that time. Since that time, LG&E has added a connection to Tennessee Gas Pipeline. Liberty finds that LG&E maintains its effectiveness through careful assessments of its customers' interests in its dealings with the pipelines, and judicious selection of occasions for negotiation, including participation in FERC proceedings.

(2) LG&E's commodity purchasing is very effective.

LG&E's status as nearly always having Kentucky's lowest gas costs demonstrates effectiveness in procurement and management of natural gas supplies. Moreover, Liberty observes that LG&E's Gas Supply Department continues to be innovative in its quest for lower commodity prices. Examples include the following:

- Flexibility provisions originally incorporated into supply contracts to accommodate load variations have been used to substitute lower-cost purchases in daily markets for first-of-the-month purchases when gas prices are declining.
- The Gas Supply Department has also experimented with "packaging" releasable pipeline capacity with commodity requirements to see whether lower commodity prices would result.

Liberty also finds that LG&E's Gas Supply Department is attentive to market developments, and personnel have a good level of understanding of the natural gas market.

(3) LG&E's attention to the administrative aspects of gas purchasing is excellent.

Liberty finds that Gas Supply's RFPs and bid documents are clear and concise; that evaluations of bids received are objective and clear; and that analysis and documentation of decisions is excellent, especially the evaluation of particular bidding experiments. Procedures and approval processes are also clear and well-documented.

LG&E has also invested considerable effort developing its contracts, including a contract for released capacity. Prospective suppliers must enter into a base (form) gas-supply agreement with the Company in order to be notified of LG&E's requirements for gas supplies. LG&E even has its own release contract with replacement shippers, to establish contractual privity and ensure payment when it releases pipeline capacity.

(4) Gas dispatching and control practices and procedures also reflect intensive effort and innovation.

LG&E's Gas Control and Storage organization uses a storage withdrawal computer model, and a neural network forecasting application to manage the Company's on-system storage resources, and to advise Gas Supply of the Company's requirements for off-system supplies. These tools, and the focused attention of Gas Control and Gas Supply personnel, allow the Company to manage its supply operations quite intensively. Those resources, in turn, allow the Company to respond rapidly to changes in load conditions and gas-market conditions.

d. Recommendations

None

4. Gas Transportation

a. Scope

This chapter addresses the Company's programs for natural gas transportation. Topics considered include the following:

- Transportation Programs Offered
- Agency Programs
- Bypass Issues
- "Prodigal Son" Customers

b. Background

(1) Transportation Programs Offered

LG&E provides two types of gas transportation service, one with a stand-by sales service (TS), and one without (FT). Both services are firm. Rate TS is available to customers who consume at each delivery point at least 50 Mcf per day or 50,000 Mcf per year. Rate FT is available only to customers who consume at least 50 Mcf per day at each delivery point. In late 2000, as a part of its general rate case, the Company added a pooling service for TS customers (PS-TS). Pooling service has been available to customers served under Rate FT (PS-FT) since 1995. The pooling services allow the pool manager to aggregate supplies and balance deliveries against usage across all of the members of a pool.

For both types of transportation service, the customer is responsible for its own pipeline capacity and its own gas supply. LG&E does not assign its capacity to or procure capacity or gas supply for any transportation customers.

The rate for the TS service is the same as the non-gas component of the Company's rate for sales service. TS customers are also charged a Pipeline Supplier's Demand Component, which is equal to the average demand cost per Mcf for all gas delivered to the Company by its pipeline suppliers. For example, for customers served under Rate IGS, the Distribution Charge per Mcf is $1.3457, and the Pipeline Supplier's Demand Component, effective February 1, 2002, was $0.8151 per Mcf.

The stand-by sales service that accompanies the Company's Rate TS provides a level of service and reliability equivalent to the underlying sales service. Because the Company provides this service through its on-system storage and contracted pipeline capacity, charges for the TS service reflect those costs. TS customers are not subject to daily balancing requirements, or to operational flow order (OFO) provisions, as the costs of daily balancing and stand-by service are reflected in their rate for transportation service. If the customer does not make arrangements for its own gas supply, LG&E is obligated to provide the supply associated with the same character of service as the underlying equivalent sales service. LG&E bills the customer for the gas consumed at the same rate as the Gas Supply Cost Component of the underlying equivalent sales service.

FT customers are charged $0.43 per Mcf. FT customers are subject to strict balancing requirements, however. Each day, usage must be within 10 percent of the quantity delivered for each customer's account. Outside of the +/- 10% tolerance, customers are assessed a Utilization Charge for Daily Imbalances. At the end of a month, any imbalance, positive or negative, is "cashed out" at a price related to the *Gas Daily* price for Dominion South Point, a market-area price index. If the Company issues an OFO, daily usage must match deliveries by a customer's supplier, with no allowance for over- or under-deliveries. During an OFO, any imbalance beyond the allowed tolerance is billed at $15 per Mcf, plus the referenced *Gas Daily* price.

FT customers may subscribe to the Company's Reserved Balancing Service (RBS). This service is available to FT customers who are concerned that they might not be able to meet the strict balancing tolerances that apply to the FT service or who want to purchase standby service for a specified amount. Quantities of RBS service are agreed to by the customer and the Company. Service under Rate RBS can be used to ensure that the customer's usage can meet the very strict balancing tolerances that apply to Rate FT.

LG&E has no obligation to provide gas, upstream transportation services or balancing services to an FT customer, except to the extent that the customer may contract for some level of the RBS service. Consequently, the FT rate does not include any costs of upstream transportation, as are reflected in the Pipeline Supplier's Demand Component of the TS rate, or on-system storage-related costs, as are reflected in the non-gas component of the Company's applicable sales service rates.

The Company's pooling services, PS-FT and PS-TS, simply allow the pool manager to combine and offset the over- and under-deliveries of customers in the pool before applying the Company's balancing requirements and charges. The daily balancing tolerance for pools customers served under Rate FT is reduced to five percent of the aggregated volumes, however. The incremental charge assessed on the pool manager for this service is an administrative charge of $75 per pool member per month.

Table 4.1, below, shows the numbers of customers and the volumes moved for both types of transportation service. LG&E reports that the TS service can act as a "try it to see if you like it" option for customers who are considering converting to transportation service under Rate FT. The statistics in the table, which show declining numbers of TS customers and increasing numbers of FT customers, are effectively showing customers "graduating" from TS to FT service.

Table 4.1 Transportation Customers & Volumes

	Rate TS		Rate FT	
	Avg. Customers	**Volumes (MCF)**	**Avg. Customers**	**Volumes (MCF)**
2001	10	241,111	81	12,866,968
2000	16	313,041	75	14,415,751
1999	19	292,940	68	12,777,366

(2) Agency Programs

LG&E does not offer agency programs under which the Company procures or manages gas supplies for transportation customers.

(3) Bypass Issues

The Company is concerned about bypass, as a significant share of its annual throughput is large-volume industrial customers, and the Texas Gas Transmission system goes through the heart of the Company's service area. The bypass risk has been successfully managed to date through the use of well-designed transportation services and special contracts. LG&E's special contracts incorporate the balancing and other supply management provisions applicable under Rate FT.

(4) "Prodigal Son" Customers

Customers who convert to transportation service have not come back. Once they make the decision to go to transportation, they find that they prefer to make arrangements that suit their requirements, such as fixed prices, capacity contracts with less storage, etc.

c. Conclusions

(1) Gas transportation service continues to increase, but slowly.

At the time of the 1995 management audit, industrial-sector sales were 10 to 15 percent of LG&E's throughput, and gas transportation was 9 to 14 percent. (The data in that Report was for the years 1990 through 1994.) The following table shows the counterpart information for the last three years:

	1999	**2000**	**2001**
Industrial Sales Volumes, %	5.7	5.7	4.7
Transportation Volumes, %	26.9	27.4	28.5

Clearly, industrial sales are down as a proportion of total throughput, and transportation volumes are up.

Liberty expects that the implied shift in this data, from sales service to transportation service, is present in comparable data from comparable utility companies across the country. It is reflective of increased access to alternative gas-supply options that has resulted from the FERC's efforts to make gas transportation service on the pipelines more broadly available.

The shift of industrial customers from sales to transportation has important implications for supply planning. In general, industrial customers have higher load factors than residential or commercial customers. In fact, making supply arrangements that are better suited to their load profile is often an important factor in their decision to switch from sales to transportation.

As industrial customers switch to transportation, however, the load factor for system-supply customers goes down. The appropriate reaction from supply planners should be to modify the Company's capacity portfolio in response to this trend. As reported in Chapter 1, Gas Supply Planning, Liberty finds LG&E's supply planning to be quite capable, and our analysis suggests a good fit between the Company's capacity portfolio and its system-supply load. Thus, our assessment is that the Company is making the necessary adjustments in its contracts with its pipelines as those contracts come up for renewal.

(2) The operational aspects of LG&E's gas transportation services are suitably protective of system-supply customers' interests.

In particular, the strict, but reasonable, balancing provisions that apply to transportation services reserve capacity resources used for balancing to system-supply customers. Moreover, the Company reports that system supply has priority access to the Company's capacity on the Tennessee Gas Pipeline system, as some lower-cost gas is available on that system.

(3) Adjustments over time to LG&E's transportation services have resulted in lower costs and risks to system-supply customers.

As suggested by Conclusion #1 above, Liberty believes that the migration of industrial customers from system-supply to transportation service is a logical result of the changes in the regulatory and business environment that have been motivated by the FERC since the mid-1980s. Liberty believes that system-supply customers have the most to lose from this migration if LDCs fail to provide reasonable access to well-constructed transportation services. What is in the system-supply customer's interest is attractive but tightly-drawn transportation services that avoid retention of capacity that may not be used.

Liberty finds a thoughtful progression in the evolution of LG&E's offerings to transportation customers. LG&E first offered its stand-by transportation service (*i.e.*, with a back-up supply service) in 1984. As noted above, LG&E views this service as a transitional one, that customers can sample to see if they want to convert to FT. Access to the stand-by service (TS) was broadened in LG&E's last rate case (2000), but the cash-out mechanism was tightened in a way that helps ensure that storage capacity is not used to accommodate end-use transportation imbalances.

The Company's non-stand-by transportation service was introduced later, in 1988. In 1995, it was tightened in ways that prevented cost-shifting to system-supply customers. Real-time meter-reading was added as a requirement for this service. That requirement further enabled tighter management of a capacity portfolio that is being held constant, or nearly constant, as LG&E's load grows.

As a part of the modifications made to Rate FT in 1995, a Reserved Balancing Service was added for those customers who are concerned about their ability to stay within the strict balancing tolerances of FT service or who desire some specified amount of standby sales service. Now, pooling services have been added for both TS and FT services to facilitate suppliers' compliance with LG&E's operating rules.

Liberty believes that these changes are in the system-supply customer's interest, as they allow the capacity portfolio to more closely match the system-supply load. That reasonable approximation should save money for system-supply customers. Liberty finds that LG&E has done a good job on this to date.

(4) Bypass threats have been successfully managed to date.

The configuration of LG&E's markets and system, largely along the route of the Texas Gas Transmission system, means that the threat of bypass is constant. LG&E's decision to shift part of its load to Tennessee Gas Pipeline perhaps magnified the threat. So far, threats have been dealt with successfully through special contracts.

(5) Transportation service customers do not share in lost-and-unaccounted-for (LAUF) volumes. (*Recommendation #1)*

Liberty finds this different from the practice of other LDCs in the state, as transportation-service customers are usually assessed a proportionate share of this amount. Three of the five LDCs that are the subject of this audit do assess a LAUF retainage to transportation, and a fourth (Columbia) assesses a LAUF retainage to its small-volume transportation (Customer CHOICE) customers.

d. Recommendations

(1) LG&E should review whether the next rate case should include a provision that transportation customers share in LAUF. (*Conclusion #5*)

The current practice of exempting transportation-service customers from LAUF is grounded in history and owes some recognition to the fact that customers served under Rate FT have a significantly higher rate of return than the system average. Moreover, the amount of LAUF that occurs in the provision of transportation service is probably less than what occurs in other segments of LG&E's markets because of the following two factors:

- Meters for transportation customers are all temperature-compensated, and temperature compensation has been found by LG&E to be the largest single factor in its LAUF number.
- Transportation customers are typically served from LG&E's high-pressure system (system operating above 60 psig) that is comprised of coated and protected pipe that is less likely to leak.

5. Gas Balancing

a. Scope

This chapter addresses LG&E's practices and procedures for balancing the Company's customers' requirements with their supplies. Topics addressed include the following:

- Metering and Testing
- Balancing Strategies and Practice
- Assignment of Capacity to Third Parties

b. Background

(1) Metering and Testing

LG&E uses diaphragm meters for smaller loads (flow rates up to 1.5 Mcf per hour), rotary meters for medium-sized loads (1.5 Mcf per hour up to 56 Mcf per hour per individual meter), and orifice meters for very large loads (only two of LG&E's large customers have orifice metering equipment). Metering equipment installed for customers receiving transportation service under LG&E's Rate FT are equipped with electronic temperature measurement devices and gas calculations are temperature compensated. Specific gravity, percentage of nitrogen and carbon dioxide is measured by gas chromatographs installed at interconnect stations with Texas Gas Transmission Corporation and Tennessee Gas Pipeline Company. This information is then used for gas computations for these transportation customers.

LG&E uses a sampling program for testing its diaphragm meters. Rotary meters are tested annually, using a differential-pressure test. Orifice meters are checked monthly. Testing procedures and frequency are consistent with general industry practice, and LG&E's permanent meter sampling plan was approved by the KYPSC by Order dated November 7, 2001, in Case No. 2000-278.

Gas use by the Company is all metered; none is estimated. Lost and unaccounted for volume (LAUF) is determined by comparing the sum of all meter readings into LG&E's facilities with the sum of all meter readings out. The difference is LAUF.

LAUF as a proportion of total throughput has varied quite a bit over the last few years. The table below shows how the percentage has varied.

Year	LAUF, Percent
1996	3.32
1997	5.20
1998	4.20
1999	2.12
2000	3.41
2001	3.97

LAUF volumes have received and are receiving considerable attention study at LG&E. Factors influencing LAUF identified to date, listed in order of significance, are as follows:

- Temperature compensation for meters
- Leaks
- Barometric pressure
- Measurement differences with the pipelines
- Calculation errors.

LG&E has always maintained its own metering equipment at all 10 of its Texas Gas city gate stations and at the two Tennessee Gas city gate stations. Both LG&E's metering equipment and Texas Gas's meters are calibrated monthly, and at the same time. LG&E reports that the two sets of measurements usually differ but typically are within one-quarter to one-half of one percent.

(2) Balancing Strategies and Practice

LG&E's Gas Control and Gas Supply groups work together to keep the system in balance. Gas Control produces a five-day system sendout forecast, based on sendout formulas provided by Market Analysis, and on a neural network forecasting application. This forecast estimates total sendout for all customers, both sales and transportation. It is updated at least once per day, and more often if weather conditions require.

Gas Supply receives nomination information for transportation customers from the pipelines. The difference between total estimated sendout and the sum of the transportation customers' nominations is the amount of gas that LG&E is responsible for delivering for system supply. Gas Control and Gas Supply determine where those amounts are to come from: on-system storage, off-system storage, pipeline services, short-and long-term commodity purchases, etc.

Gas usage by transportation-service customers under Rate FT is metered and such measurement can be accessed remotely through telemetry equipment. Data from those meters are downloaded daily. Usage information can be compared daily to nominations, and transportation customers who are out of balance can be instructed to bring their nominations and usage into balance.

For system supply, deliveries from firm pipeline transportation capacity match nominations. Any difference between system supply requirements and nominations, due to the difference between forecasted and actual weather or other operational requirements, for example, is handled through either the off-system storage component of LG&E's NNS service from Texas Gas or LG&E's on-system storage.

As reported in Chapter 4, Gas Transportation, LG&E's transportation services are subject to strict balancing provisions. The Company has a Pooling Service to allow customers under Rates TS and FT to allow a Pool Manager to aggregate, manage and balance end-use customers' gas supplies. In this way, individual customers within the Pool can have more flexibility to vary their usage without concerns about violating LG&E's balancing tolerances.

(3) Assignment of Capacity to Third Parties

LG&E does not assign pipeline capacity to third-party suppliers of its customers. Transportation customers, or their supplier, are responsible for obtaining their own capacity.

c. Conclusions

(1) LG&E has made considerable progress in gas measurement and control since the 1995 management audit.

The increasing proportion of LG&E's sendout that consists of transportation volumes, and monthly and daily pipeline balancing requirements in the wake of the FERC's Order 636, led LG&E to require all transportation-service customers served under Rate FT to implement real-time electronic metering. Only two transportation customers had real time metering in late 1994. By late 1995, however, telemetry was required for all customers served under Rate FT pursuant to tariff modifications proposed by LG&E and approved by the Commission in that year. All customers served under Rate FT now have and are required to have telemetry.

LG&E's Supervisory Control and Data Acquisition (SCADA) system has also been replaced since the prior management audit. The new system includes remote terminal units at 12 city-gate stations, two compressor stations, three gas-recovery compressor stations and 10 other regulation and measurement stations. Flow is monitored into and out of all five storage fields, and monitored and/or controlled at all 12 city-gate stations. The new system also provides several additional operational and configuration enhancements.

(2) LAUF has continued to increase since the management audit, but it is receiving considerable attention. *(Recommendation #1)*

LG&E's LAUF percentage was identified as an area of concern during the management audit. (See the Management Audit Report, pp. 492-494.) Over the four years prior to the management audit, the average LAUF percentage was 2.97; in the six years since, the percentage has averaged 3.70. (See the table in the first part of this chapter.)

The erratic nature of the year-to-year figures, and the steady increase in the average, has caused the Company to focus on trying to understand the source of this problem. In 2002, LG&E's Internal Audit Department was requested to initiate a study of the issue. Objectives of the study include the following:

- Ensure that policies and procedures concerning the maintenance of gas meters are being adhered to;
- Review areas comprising lost and unaccounted for gas to identify possible loss reduction solutions;
- Determine that the lost gas percentage is being calculated accurately and properly; and
- Identify ways to optimize the processes by which gas is managed.

The study's scope is to include accounting procedures; meter maintenance; fugitive emissions and leaks; temperature and pressure effects on delivered volumes; un-metered gas lights; unbilled meters; theft; and accounting adjustments. The study is due to be issued to LG&E management soon. Factors contributing to meter errors and identified to date are those listed earlier in this chapter: lack of temperature compensation on metering equipment; underground pipeline leaks; fugitive emissions; metering differences between LG&E and the pipelines; etc.

Also since the management audit, LG&E has adopted a systematic, large-scale infrastructure-replacement program for aging unprotected gas mains. The decision to undertake this program was based on a life-cycle optimization analysis to determine the best approach to the problem. LG&E is currently making significant capital expenditures on this program, and is expecting to continue replacement of its unprotected bare steel and cast/wrought iron mains until completed.

(3) LG&E's pooling services should help all classes of customers.

The purpose of the pooling services is to allow gas marketers to balance supplies and usage across their customers, rather than having to balance each one separately. The Company has separate pooling services for TS and FT customers because of the differences in those two services. Since almost all users have at least some variation in their usage patterns, this service allows day-to-day variations in usage to offset each other. LG&E charges only a per-customer administrative fee for these services, which should facilitate the marketers' operations by giving them more flexibility.

A condition of the Rate FT pooling service, however, is that the balancing tolerance is tighter, plus or minus 5 percent of the pool's usage, as opposed to plus or minus 10 percent when each customer balances separately. Using the services to balance customers' usage jointly should make balancing easier for the marketers, but LG&E balancing tolerances under this transportation help to prevent abuse of the extra flexibility. The tighter tolerances on transportation services help sales-service customers by reducing the level of capacity resources that all customers must pay for, and by facilitating LG&E's close control of its own system.

d. Recommendations

(1) LG&E should provide the Commission with its findings and proposed actions on its recent study of LAUF when they are available. *(Conclusion #2)*

Liberty recommends that the Company report to the Commission on its findings and proposed actions as a part of the follow-up contemplated under this procurement audit.

6. Response to Regulatory Change

a. Scope

This chapter addresses the changes in the conduct of the gas supply function at LG&E that have occurred in response to changes in its business and regulatory environment, particularly the FERC's Order 636, issued in April 1992. Topics addressed include the following:

- Changes in Objectives for Supply
- Changes in Supply Activities
- Capacity Cost Reduction

b. Background

(1) Changes in Objectives for Supply

Over the period of its existence, LG&E's objectives for its gas-supply function have evolved with changes in the gas industry. LG&E's predecessor companies started with gas manufactured from coal. Natural gas produced in the region became part of the City's supply in the late 1800s. Natural gas increased in importance at the time of the consolidation that formed LG&E in 1913, and became the sole component of supply in 1950. Gas from West Virginia was added in 1927, and gas from the Gulf Coast was added with the Company's connection to the Tennessee Gas Pipeline system in 1944. The Muldraugh storage field was developed in 1929, and four other storage fields were added in 1946, 1959 and 1968.

LG&E's relationship with the Texas Gas Transmission system began with the completion of that pipeline system, routed through the heart of the Company's service area, in 1949. LG&E ended an earlier supply contract with Kentucky-West Virginia Gas Company in 1962, and became a full-requirements customer of Texas Gas, including terminating its relationship with Tennessee, in late 1967.

With the FERC's Order 436 (implemented in late 1985), LG&E was able to return to buying at least some of its own gas. In fact, the Company took advantage of the access to pipeline transportation capacity provided by that change, and proceeded to displace purchases from Texas Gas with lower-cost spot-market supplies. The 1995 Management Audit Report notes that, for calendar years 1990, 1991 and 1992, spot-market gas was 60 to 70 percent of the Company's supplies, whereas pipeline supply had declined to 27 to 35 percent.

With implementation of Order 636, which occurred toward the end of 1993, the Company assumed responsibility for its entire supply portfolio. To prepare for the negotiations that led to that implementation, LG&E did an extensive analysis of its requirements, and of Texas Gas's service offerings. The Company selected a mix of FT and NNS services, and negotiated contracts with a wide range of expiration dates and renewal terms. LG&E also used its experience buying spot gas to develop portfolio guidelines for its commodity purchases.

The Company's supply problem, from its beginnings through the curtailments of the early 1970s, was to get enough supply. Since elimination of those shortages, a competitive price has been a consideration. Since taking over the supply function from the pipelines, the Company has pursued twin goals: Purchase the most economical gas supplies consistent with reliability of supply.

(2) Changes in Supply Activities

The gas-supply function was administered by LG&E's Rate Department until late 1986. The Company established the Gas Supply Department (*Gas Supply or Department*) at that time.

From that point until the beginning of the Order 636 implementation process, Gas Supply's activities were largely comprised of using spot-market gas to displace purchases of gas from Texas Gas. Spot-market gas was considerably less expensive than pipeline supply. As previously noted, by using its on-system storage facilities and its access to firm transportation capacity during the heating season, LG&E was able to get its spot purchases up to 60 to 70 percent of total purchases, with considerable benefit to the Company's weighted average cost of gas. That activity also provided considerable experience with the pipelines' nominations and scheduling processes.

Gas Supply did an enormous amount of analysis of its pipeline transmission and storage capacity options in preparing for, and then participating in, the 636 implementation process. The group also worked extensively on strategies for commodity contracting at that time.

Since Order 636 implementation, and although Gas Supply has been in an operations mode, the Department has continued to experiment with the terms and provisions of commodity-purchase arrangements. In this mode, Gas Control is responsible for the overall operation of the distribution system, and for dispatching gas to and from LG&E's on-system storage facilities. Gas Supply manages gas supplies and transportation services to get gas to LG&E's city gates. Gas Supply also buys gas as required after reflecting on-system storage operations.

A connection to a second pipeline, the Tennessee Gas Pipeline system, has been added since Order 636 was implemented. Load growth and the continuing shift of large-volume customers from sales to transportation service have also required adjustments to the Company's Texas Gas contracts. Finally, the FERC has issued at least one additional order regarding the competitive framework in the gas industry (Order 637). That issuance has required negotiations over implementation with both of the Company's pipeline suppliers, although the effects of the change do not seem to be great.

From its inception, the Gas Supply Department has added staff only slowly. Its size today (five) is the same as it was at the time of Order 636 implementation. Analytical tools have been added, however. The Group purchased SENDOUT in 1994. Gas Control has also added a neural network forecasting model in an effort to improve its short-term requirements forecasts.

(3) Capacity Cost Reduction

LG&E does not maintain pipeline capacity for its transportation-service customers. The Company also does not retain any capacity to provide supply to customers whose suppliers fail to deliver. If the Company has supply available in those circumstances, it will provide gas supplies in accordance with the terms and conditions incorporated in the applicable rate schedule, but no extra supply resources are maintained for that purpose.

As previously noted, the Company experienced some reductions in its requirements for pipeline capacity as a number of its larger-volume customers switched from sales to transportation service around the time that Order 636 was implemented. The Company has been adding about 5,000 customers per year, however, so load growth has absorbed capacity that might otherwise have been reduced as the result of customer migration from sales to transportation-only service. In fact, LG&E has already extended a Texas Gas contract that was not due to expire until 2003, as the Company needed additional pipeline capacity.

The Company conducts both capacity-release activities and off-system sales. Capacity-release revenues declined over the 1999-2001 period, as the market for the Company's contracted capacity is strong typically only at the same time as the Company needs the capacity for system supply. Off-system sales produce more in net revenue than the amount of revenue generated by capacity release activity. Both types of transactions are encouraged by the Company's performance-based rate-making (PBR) mechanism, which provides for sharing between the Company and its customers any margins generated.

LG&E's off-system sales transactions almost all occur in the production area. Customers are the same companies that LG&E buys gas from. In fact, the Company enters into an agreement covering both purchases and sales when it takes on a new supplier, in order to facilitate these transactions.

LG&E has also negotiated discounts off of the pipelines' FERC-approved transportation rates. LG&E does not get the discount on capacity releases to third parties, or capacity used in off-system sales, at delivery points other than the Company's city gates, however.

c. Conclusions

(1) LG&E and its customers have benefited enormously from the continuity in the Company's Gas Supply Department.

The same person has headed LG&E's Gas Supply Department since it was formed in 1986. Other members of the Department have been in place for extended periods. This continuity has afforded the Company an important institutional memory as the gas market has changed in response to regulatory changes. This continuity has also resulted in considerable sophistication in presenting and advancing the interests of the Company's customers.

(2) The Company's Gas Supply Department continues to do an excellent job of identifying and analyzing issues that will have an important effect on the Company's performance in gas purchasing.

The Company's very impressive record in keeping its rates down provides sound evidence on the excellent job done in the area of gas supply procurement and management. Liberty also finds the Department's approach to areas such as participation in FERC proceedings to be efficient and effective.

(3) The Commission's management audit program has also contributed to LG&E's gas-purchasing success.

LG&E's Gas Supply Department is inclined to seek external assistance only in areas where it has identified a particular need or interest. The Commission's management audit program is a more broad-based review of jurisdictional companies' operations. Such a broader review will often produce findings that the Company either had not focused on, or had not fully appreciated. The connection to Tennessee Gas Pipeline, shorter-term commodity contracts, and a continuing role for spot-market gas after Order 636 implementation, are examples of suggestions from the 1995 management audit, all of which LG&E had plans to implement prior to the Management Audit, that have turned out well for the Company and its customers. The audit's suggestion to explore the causes of the Company's increasing LAUF percentage, and its suggestions about operational measures to reduce that percentage, were also helpful.

d. Recommendations

None

7. Affiliate Relations

a. Scope

This chapter of Liberty's report addresses the affiliate relations aspects of Louisville Gas and Electric Company (LG&E) gas procurement practices:

- Structure of Affiliated Companies.
  - Placement and Structure of the Gas Procurement Function within the Affiliated Companies.
- Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.
  - Non-Gas Transactions with Affiliated Companies.
- Accounting and Reporting Issues for Affiliate Transactions
  - Cost Allocation Manual (CAM)
  - Allocation of Employee Time and Overheads
  - Other Accounting Issues
- Affiliate Transactions Relative to KRS 278
- Other Issues

b. Background

(1) Structure of Affiliated Companies and Placement of Gas Procurement Function

LG&E, a Kentucky corporation, is a wholly-owned subsidiary of LG&E Energy Corp. (LG&E Energy), a Kentucky corporation. LG&E Energy's parent company is Powergen plc, of the United Kingdom. On July 1, 2002, Powergen became a wholly-owned subsidiary of E.ON AG of the Federal Republic of Germany. Currently, both E.ON AG and Powergen are registered holding companies under the Public Utility Holding Company Act of 1935. LG&E Energy Services, Inc. (Servco), a Kentucky corporation incorporated June 2, 2000, is an affiliate company that provides a variety of administrative, management and support services to LG&E Energy's utility and non-utility subsidiaries.

The Gas Management Planning and Supply Department (*Gas Supply*) is part of LG&E, not LG&E Energy Services, Inc. Gas procurement is done in-house only for LG&E, and there are no affiliate issues with any other sister companies.

(2) Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

Gas Supply has no gas procurement transactions with affiliated companies. The department does procure gas commodity for five (5) electric stations behind the LG&E distribution system. Of those five plants, all but one use LG&E's system supply gas as needed. Those plants are charged the average purchased gas cost (WACOG) for the month. The remaining plant (Paddy's Run Unit 13), a gas peaking unit that cannot be served using pipeline capacity already under contract to LG&E for its system supply purchases, formally requests gas purchases as needed. Gas Supply makes a discrete purchase as requested, and the plant is only charged the cost of that discrete purchase transaction, regardless of the WACOG. Additionally, Gas Supply provides a daily, non-binding indicative price for the next day's gas flow, which is used by electric dispatch in determining whether or not a purchase may be either economical or required. Gas Supply also provides the accounting and transaction tracking functions associated with these discrete purchase transactions. For these procurement services, the plant is allocated one (1) hour (burdened rate) of one person's time per day, whether or not a gas purchase is requested.

(2a) Non-Gas Transactions with Affiliated Companies.

Gas Supply's transactions with Servco are covered in detail by the Cost Allocation Manual.

(3) Accounting and Reporting Issues for Affiliate Transactions

(3a) Cost Allocation Manual (KRS 278.2205)

Costs among affiliated companies are allocated based upon extensive, comprehensive guidelines detailed in the Servco Cost Allocation Manual (CAM). As stated on page three of the CAM, "The overriding goal of the [CAM development] project team was to ensure the methods, policies and procedures contained in this CAM were PUHCA compliant so that Servco costs are fully segregated, and fairly and equitably allocated among the affiliate companies to protect investors and consumers." Sections in the CAM include: Description of Services, Corporate Organization, Transactions with Affiliates, Cost Apportionment Methodology, and Time Distribution. The CAM is based upon Service Agreements filed with the SEC under PUHCA.

(3b) Allocation of Employee Time and Overheads

The CAM details three methods of time reporting: positive, allocation, and exception. The differences among the three and their appropriate uses are spelled out in the CAM. The accounting department, for example, is a Servco group that uses positive time reporting to record hours spent working on affiliate companies, and timesheets are submitted bi-weekly. Gas Supply, which is within LG&E, uses exception time reporting if work is done for another cost center or affiliate company.

(3c) Other Accounting Issues

There are no affiliate subaccounts set up for the gas procurement function in the chart of accounts, because there are no affiliate transactions to account for with regard to gas supply. Affiliate transactions in other areas are recorded as addressed in the CAM. All affiliate transactions are recorded as intercompany receivables and payables, and cleared every month.

(4) Affiliate Transactions Relative to KRS 278

Gas Supply appears to be in compliance with KRS 278. The company has been part of a holding company for more than a decade, and believes it has been in the forefront with regard to intercompany accounting.

c. Conclusions

(1) LG&E is a subsidiary of LG&E Energy Corp., which is a subsidiary of Powergen plc (UK) which, in turn, is a subsidiary of E.ON AG (Germany). LG&E Energy Services, Inc. (Servco) provides multiple administrative functions (accounting, human resources, legal, etc.) for all of the affiliated LG&E Energy Corp. companies.

Service companies providing common administrative functions are typical for registered utility holding companies under the Public Utility Holding Company Act of 1935. Gas Supply has very few or no dealings with any LG&E Energy affiliated companies besides Servco.

(2) The gas procurement model is based entirely on in-house procurement by a department of LG&E (Gas Management Planning and Supply), not a shared services unit, and presents no issues concerning affiliate relations.

Because Gas Supply operates only within and for the benefit of LG&E, there are none of the allocation issues inherent with a shared service unit. No affiliate pipelines exist, and an affiliate gas gathering company (which was sold in early 2001) had not been - and due to its location, probably could not have been - used as a supplier.

(3) LG&E is a combination gas and electric utility, and Gas Supply provides gas for five (5) electric plants behind the LG&E distribution system. The methods used to charge the plants for gas are appropriate.

Gas Supply procures gas for start-up and stabilization at four (4) of the electric plants, and the electric side of the company pays the average purchased gas cost. The remaining plant (Paddy's Run Unit #13) requests gas as needed, and Gas Supply makes a discrete purchase to meet that requirement, charging the actual cost of the discrete purchase. Further, to insure that no cross-subsidization between the gas and electric sides takes place, Gas Supply charges one (1) hour of time per day for services related to pricing, purchasing, and accounting for that supply.

(4) Costs among affiliated companies are allocated based upon extensive guidelines summarized in a very complete Cost Allocation Manual (CAM).

LG&E Energy Services' Cost Allocation Manual is exemplary. The CAM provides both the company and the Commission the background, the allocation philosophy and the methodological details necessary to provide for a fair and accurate allocation of shared costs.

(5) Employee time is allocated among the companies based upon guidelines in the CAM.

Time reporting is a separate section of the CAM, and the chapter details the methodology and appropriate application of three types of time reporting. For example, the accounting department (a shared services unit) uses positive time reporting to record the hours spent working on affiliate companies, and the timesheets are submitted bi-weekly. The gas procurement group uses exception time reporting if work is done for another cost center or affiliate company. In interviews, management personnel evidenced a good understanding of the time reporting procedures and requirements.

(6) The gas procurement function appears to be in compliance with KRS 278.

Transactions with Servco (the shared services affiliate), which are detailed in the CAM, are based upon Service Agreements that have been filed with the SEC as required by PUHCA, and therefore meet the pricing requirements of KRS 278.2207. Gas procurement services provided to five electric plants behind the LG&E gas distribution lines (see Conclusion #3) are appropriately charged to the electric side of the utility.

(7) There are no affiliate subaccounts set up for the gas procurement function, because there are no affiliate transactions to account for with regard to gas supply. Affiliate transactions in other areas are addressed in the CAM, recorded as intercompany receivables and payables, and cleared every month.

As has been noted previously, Gas Supply has no dealings with affiliates other than Servco.

d. Recommendations

None.

III. Company-by-Company Reports

D. Union Light, Heat and Power Company

1. Gas Supply Planning

a. Scope

This chapter of Liberty's report addresses the aspects of the Union Light, Heat and Power Company (*ULH&P*) gas supply planning practices:

- Integration with Corporate Plans
- Load Forecasting/Risk Analysis
- Balancing Supply Options/Capacity Portfolio Analysis
- Supply Planning Flexibility
- Impact of New Markets
- Monitoring of Key Assumptions and Plan Implementation
- Peak Period Performance

b. Background

(1) Integration with Corporate Plans

Natural gas supply planning, procurement and management for ULH&P are handled by the Gas Resources Department (*Department*) of Cinergy. This Department is one of six departments reporting to the Cinergy Vice President of Gas Operations. The Cinergy Vice President of Gas Operations reports to the Vice President, Chief Operating Officer Regulated Businesses, Energy Delivery for Cinergy, who in turn reports to the President of Cinergy Regulated Businesses.

Also reporting to the President of Cinergy Regulated Businesses is the President of Cincinnati Gas & Electric Company (*CG&E*). This individual also serves as the President of ULH&P.

The Gas Resources Department is in charge of gas supply operations, and consists of a supply analyst, a transportation analyst, two gas purchase administrators and a gas procurement analyst. The current manager of the Gas Resources Department is scheduled to retire within the next several months. A complete discussion of the organizational structure and responsibilities within the Gas Resources Department is contained in Chapter 2, Organization, Staffing and Controls.

The Gas Resources Department purchases 59 Bcf of natural gas per year and serves customer demand for CG&E, ULH&P and Lawrenceburg Gas (*LG*) through a total pipeline capacity of 676 KDth per day. Of this total, ULH&P accounts for 10 Bcf of gas sales for over 86,000 customers, and 2.8 Bcf of gas transportation services.

The Vice President of Gas Operations and the Manager of the Gas Resources Department jointly perform strategic planning for ULH&P. The Gas Supply Analyst provides analytical work that supports strategic planning. Annual reports generated by the Department include the gas cost budget, capacity portfolio analysis, and an annual gas supply plan. Forecasted information, such as peak day sendout and winter load regression equations, is provided by the forecasting group. The Gas Supply Analyst uses this information to generate long-term forecasts and a capacity portfolio analysis including a load duration curve.

The Vice President of Gas Operations reviews the annual plan with the Vice President/COO of Energy Delivery and provides updates every 6 months unless there are specific items that require earlier review.

ULH&P's supply planning practices are integrated with those of CG&E and Cinergy corporate planning due to the nature of the business model. ULH&P is in a desirable position because of the relationship with CG&E and as a result the overall planning benefits from the additional flexibility and balancing capabilities provided by the interconnects with CG&E's distribution system.

ULH&P has a portfolio management service and gas purchase agreement with an asset management firm to manage its asset portfolio. This includes management of all firm supply, pipeline and storage capacities in exchange for an agreed-upon monthly payment from the asset manager to ULH&P. Due to the nature of the agreement, the Gas Resources Department performs 'virtual dispatch' of resources on an ongoing basis. Included in this virtual dispatch are projections of how storage balances should be used, as well as projections of gas costs incurred for the overall portfolio. The Department informs the asset manager of the results of this virtual dispatch and how ULH&P would like to use the resource portfolio to meet demand requirements for ULH&P. While the asset manager has the ultimate decision of how the resources are used physically, ULH&P pays only for the services and utilizations that are virtually dispatched.

(2) Load Forecasting/Risk Analysis

Inputs from the Load Forecasting Department provided to the Gas Supply Analyst constitute the basis for the long-term and short-term forecasts for ULH&P. Demand is estimated using econometric equations. These equations are based on a number of factors including the number of customers, base and heat sensitive usage per customer for residential customers as a function of heating efficiency, saturation, and price and weather variables. Firm and interruptible deliveries for commercial, industrial, and Other Public Authority (OPA) sector demand are estimated using various economic, gas price and weather variables.

Peak load is estimated separately as a function of weather normalized sendout on a total system sendout basis. The peak load is assumed to occur in January, and a 3% risk level is assumed for the design day requirement. This means there is a 3% probability that weather colder than the design day can occur.

For supply planning, ULH&P uses a program that utilizes Monte Carlo simulations on a monthly basis. This Monte Carlo simulation analysis package is used to calculate base versus swing gas requirements and to determine optimum gas procurement prices. Using daily historical sendout data, the Monte Carlo simulation considers potential variation from statistical parameters and permits the analysis of all possible scenarios to ensure that gas supply requirements are met. This technique enables the Department to conduct a proper risk analysis with respect to meeting system gas demand.

While there are no formal policies related to any level of supplier diversity, ULH&P strives to provide for adequate supplier diversity in the assembly of its gas portfolio.

(3) Balancing Supply Options/Capacity Portfolio Analysis

ULH&P's contiguous service territory is located in Northern Kentucky on the Ohio River across from Cincinnati, Ohio, and includes Florence, Alexandria, Falmouth, Williamstown and Warsaw. This area is directly served by four interstate pipelines including Columbia Gas Transmission (CGT), Columbia Gulf Transmission, Tennessee Gas Pipeline (TGP), and Texas Eastern Transmission (TET). ULH&P is currently being served by all of these pipelines except for TET. KO Transmission, a wholly-owned subsidiary of CG&E, jointly owns an interstate pipeline (KO 45%, CGT 55%), and provides interstate pipeline transportation capacity from Columbia Gulf and TGP to the ULH&P city-gate. Furthermore, the ULH&P gas distribution system is connected to the CG&E gas distribution system by four pipelines crossing state borders under the Ohio River. This allows for considerable flexibility and the possibility of gas purchases from pipelines in Ohio such as Texas Gas Transmission, TET, ANR, CGT and Consolidated Natural Gas (CNG, now Dominion). These pipelines form a hub at Lebanon, Ohio.

Since ULH&P does not have on-system storage to perform peak shaving, it relies on pipeline storage service from Columbia, uses a propane facility in Erlanger, KY, and also a 25-day peak shaving service from their asset management firm.

The Gas Supply Analyst prepares a capacity portfolio analysis each year using peak day forecasts. This forecast identifies gas supply alternatives for the portfolio as necessary to match the load duration curve. Over the last few years, the gas supply portfolio has changed as necessary to better match the forecasted load. Contracts have been retired or supplanted as necessary to achieve a portfolio that best matches the load duration curve.

Over 5 years ago, ULH&P evaluated gas supply optimization software and found that the costs were not justified. Thus, it effectively uses its own spreadsheet programs to conduct the capacity portfolio analysis.

Liberty's ROGM analysis indicates that ULH&P's current portfolio constitutes a tight fit to forecasted demand. Furthermore, ULH&P's Monte Carlo analysis, unique among Kentucky gas utilities, enables the evaluation of potential variation in the portfolio mix. Thus, ULH&P is able to better understand and formalize the degree of coverage ensured by the portfolio mix. This sophisticated portfolio analysis contributes to ULH&P having one of the lowest gas costs among Kentucky gas utilities.

In conjunction with ULH&P's resource management contract with the asset management firm, ULH&P conducts an ongoing virtual dispatch of gas supply resources. This activity is conducted just like the preparation of a regular gas supply plan. While this does add a layer of separation between ULH&P requirements and the actual physical dispatch, as far as forecasting and portfolio planning is concerned, the process has not changed due to this contract.

(4) Supply Planning Flexibility

ULH&P's resource mix seems to provide an adequate level of supply planning flexibility. The Company currently has 3 firm gas supply providers, and also has balancing capability within its resource management contract.

ULH&P has good short-term planning flexibility that is provided through use of the Monte Carlo simulation program. Short-term gas requirements provided by this program enable evaluation of all possible demand scenarios, given historical variation. The program further enables the proper assessment of base and swing gas requirements and any necessary storage withdrawal.

While the interstate pipelines in Ohio are not in ULH&P's gas supply portfolio, the unified nature of its system with CG&E's gas distribution system allows for CG&E and ULH&P to balance gas between the two systems. From an operational standpoint, this allows for additional flexibility beyond that provided by the assigned ULH&P contract amounts.

(5) Impact of New Markets

ULH&P does not consider the impact of new markets beyond changes resulting from expected increases in the number of customers and changes to saturation figures.

(6) Monitoring of Key Assumptions and Plan Implementation

The document outlining responsibilities of the Gas Supply Analyst for management of gas supply and risk management includes sections that indicate proper procedures are in place to handle changes in the virtual dispatch on a monthly basis. However, the Company's analysis of forecasted vs. actual sendout is limited to daily supply decisions. There is no proper comparison of actual sendout with 10,000 runs of the Monte Carlo simulation program. However, while the Company's Monte Carlo simulation does not lend itself to "back-casting", the Company does perform a comparison of actual send out to the forecasted range produced by the Monte Carlo simulation. A more comprehensive forecast methodology would allow the tracking and comparison of changing demand sensitivity to weather and hence a more timely update of the resource mix.

(7) Peak Period Performance

ULH&P's peak period performance was one of the best when compared to the other four Kentucky LDCs examined as part of this project, in terms of cost of gas for the 2000-01 heating season. Furthermore, the employment of a Monte Carlo simulation methodology ensures that reasonable demand scenarios are covered in the assessment of an adequate supply portfolio and that ULH&P's gas supply requirements will be met.

c. Conclusions

(1) ULH&P has commendable gas demand forecasting procedures, and could improve the long-term demand component of this process. *(Recommendation #1)*

Gas demand forecasting procedures used by ULH&P contain the desired elements of analysis, such as number of customers, usage per customer, a level of weather variation coverage determined by incorporating a cost trade-off analysis, and an appropriate peak-day forecast procedure.

ULH&P is unique among Kentucky LDCs in its use of the Monte Carlo simulation technique to perform simulations of the Company's monthly gas supply requirements. This ensures that gas supply purchases are made after incorporating consideration of potential variation in demand. The same methodology can also be applied to long-term demand forecasting. However, ULH&P does not use the model for this purpose.

ULH&P's sophisticated use of the proper level of risk related to weather variation in its portfolio management, along with use of Monte Carlo methodology, enables the Company to better match the load curve and ensure ongoing peak period performance of the gas supply portfolio.

(2) ULH&P has commendable gas supply portfolio-planning procedures, and could improve the process by use of a gas supply optimization model. *(Recommendation #2)*

ULH&P has one of the lowest gas costs among Kentucky utilities. A contributing factor to this good performance is the match between the Company's gas supply resource portfolio and its load duration curve made possible by the use of Monte Carlo analysis for monthly gas supply requirements.

ULH&P's gas supply planning practices are integrated with CG&E planning due to interconnects with CG&E's distribution system. Thus, ULH&P is able to capitalize on balancing between the two systems and achieve more flexibility in its gas operations. ULH&P also seems to adequately manage its gas portfolio by appropriately retiring unused contracts, and continually seeking supplier diversity in the assembly of its gas portfolio.

Liberty's ROGM analysis confirms the appropriateness of the Company's gas supply portfolio. However, ULH&P itself could perform more thorough gas supply portfolio planning using a gas supply optimization model. Currently this is not conducted through use of any formal model and any optimization is a manual process based on estimates. While this is the case, the limited number of contracts currently in the ULH&P resource portfolio, and the unified nature of its service territory allow the Company to optimize its resource requirements with relative ease.

ULH&P's resource mix seems to provide the Company with an adequate level of supply-planning flexibility. Incorporating load variation in the Monte Carlo analysis enables the proper assessment of appropriate levels of the more costly swing gas and storage requirements.

d. Recommendations

(1) Improve the seasonal component of demand forecasting by incorporating Monte Carlo methodology. *(Conclusion #1)*

While ULH&P's gas supply forecasting procedures are commendable, they can be improved by using a Monte Carlo methodology in generating its long-term gas supply forecast. Furthermore, ULH&P can incorporate steps that will allow tracking any demand changes that are expected due to decreased demand or due to system improvements. Using this methodology in the development of the long-term demand forecast would ensure that all reasonable demand scenarios are covered in the generation of its forecast and hence the assessment of an adequate supply portfolio. The result would be a continued fit of the resource portfolio to demand requirements, and customers would reap the benefits of system improvements

(2) Refine the gas supply portfolio by incorporating use of a gas supply optimization model in portfolio planning. *(Conclusion #2)*

With several interstate pipeline and gas supply contracts due to expire in 2004, there are potential impacts to the gas supply portfolio that must be clearly understood. Use of a formal gas supply optimization model would enable faster analysis, and analysis of more alternatives than is now possible with the manual estimation procedures.

Use of a formal optimization model would permit a more comprehensive tracking and comparison of changing demand sensitivity to weather, evaluations of tradeoffs between peaking and storage utilization, and hence a more timely update of the resource mix.

Such a formal model can be constructed on an optimization spreadsheet with internal resources and need not be procured from more expensive external resources.

2. Organization, Staffing and Controls

a. Scope

This chapter of Liberty's report addresses the aspects of the Union Light, Heat, and Power Company (*ULH&P*) management and operations that relate to its overall organization, staffing and controls:

- Organizational Structure.
- Staffing.
- Approval Authorities.
- Work Process Definition and Control.
- Documentation Requirements.
- Auditing.

b. Background

(1) Organizational Structure & Staffing

Natural gas supply planning, procurement and management for ULH&P is handled by the Gas Resources Department (Department) of Cinergy. This Department is one of six departments reporting to the Cinergy Vice President of Gas Operations. The Cinergy Vice President of Gas Operations reports to the Vice President, Chief Operating Officer Regulated Businesses, Energy Delivery for Cinergy, who in turn reports to the President of Cinergy Regulated Businesses.

Also reporting to the President of Cinergy Regulated Businesses is the President of Cincinnati Gas & Electric Company (*CG&E*). Since ULH&P is a wholly-owned subsidiary of CG&E this individual also serves as the President of ULH&P.

The Gas Resources Department is directed by the Manager, Gas Resources, located in Cincinnati, Ohio. This seven person Department, including the Manager, is responsible for the development of all gas supply and system management strategies and the procurement of all natural gas and pipeline transportation services required to reliably deliver adequate quantities of natural gas to ULH&P. This Department is also responsible for gas procurement for the other two regulated LDCs of Cinergy, CG&E and Lawrenceburg Gas Company.

The primary responsibilities of the Gas Resources Department, related to all three LDCs, are as follows:

- Purchase natural gas supplies (59 bcf/yr.) on a daily, monthly and seasonal basis.

- Secure and manage interstate pipeline capacity (676,000 Dth/d – winter) including capacity release and off-system sales.

- Schedule, confirm and record natural gas daily deliveries to CG&E/ULH&P/Lawrenceburg Gas's city gate.

- Coordinate with CG&E/ULH&P/ Lawrenceburg Gas's Gas Control and Gas Transportation Departments daily supply and system balancing requirements, issuance of Operational Flow Orders (OFO's) to gas transportation customers' suppliers and curtailment of interruptible gas transportation customers on peak days.

- During the Commission's management performance audits, demonstrate that CG&E/ULH&P/ Lawrenceburg Gas's gas procurement policies and practices were reasonable and consistent with obtaining reliable gas supplies at reasonable prices.

- To provide expert testimony and to interface with the various Commissions regarding gas supply and interstate pipeline capacity matters.

- Perform supply analysis – develop probabilistic models for storage management, peak day and seasonal designs, daily and monthly supply/interstate pipeline capacity release planning.

- Perform risk management (price hedging) to minimize price volatility.

- Audit, process and approve for payment gas supplier and interstate pipeline invoices ($266 million for 2000).

- Prepare Expected Gas Costs for inclusion in quarterly GCR/GCA filings with the PUCs.

The Gas Resources Department works most closely with two of the other seven departments reporting to the Vice President of Gas Operations, the Gas Control Department and the Gas Rates & Transportation Department.

The Gas Control Department consists of a Manager, Gas Control, and his support staff of nine gas controllers and one supervisor who handle the gas control operations. Gas Control operates 7 days per week, 24 hours per day. The gas control section is responsible for the daily operation of the Company's gas control function by monitoring, balancing, and controlling of gas supply deliveries across the systems to ensure that the systems are performing in a safe and reliable manner.

The Gas Rates & Transportation Department consists of a Manager and his support staff of seven individuals. This group is responsible for certification of suppliers in transportation programs, and for contracting and supplier deliveries on interstate pipelines. The group monitors daily pipeline deliveries and handles billing for large volume customers. They administer the KO Transmission pipeline, an interstate pipeline affiliate, and are involved in FERC rulemaking and rate case issues.

Performance Measurement

Performance measurement for employees in the Gas Operations group is handled in accordance with the overall Cinergy program for employee performance management. In general, this program consists of several components. Employee performance is evaluated annually using the KPI, or Cinergy key performance indicator program. This method evaluates measurable performance, not just activity, and applies to employees at the Manager level and above. Through this system, the Manager's performance is measured against other Kentucky LDCs including LG&E, Western Kentucky Gas and Columbia Kentucky. Outside of Kentucky, he is measured against Columbia Ohio, DP&L and East Ohio Gas. Reviews conducted at the end of each year between employees and managers can result in salary increases.

Another aspect of employee evaluation is the AIP – annual incentive program. This program has three components: earnings per share (EPS), unit performance, and individual performance. For example, the Department Manager's goals for the AIP could be based upon actual gas costs and how they compare to gas costs for other Kentucky utilities. The system allocates a range of points depending on the level of achievement, and the accumulation of points under several performance indicators could result in incentive awards.

Beyond these structured performance measurement systems, the Vice President of Gas Operations monitors the performance of his people on a number of issues to determine if the overall performance of his group is meeting his expectations. For example, he follows the daily gas meetings and observes whether or not gas is available in the quantities, locations and pressures necessary to meet the forecasted requirements.

A further checkpoint on the short-term outlook is the regularly scheduled weekly gas planning meeting, where decisions are made on issues that are outside the scope of the daily meeting. On a weekly basis, the five staff members of Gas Resources meet in what can be characterized as an abbreviated version of the monthly supply planning meeting, where the groups takes a quick look at what has happened over the last week in terms of gas nominations and usage to determine if short term adjustments might need to be made. The Vice President receives a copy of the written notes of the meeting, and checks that the action plans have been set into motion.

Another measure of performance is the monthly supply planning meeting. This meeting looks at monthly supply planning – how much base gas is nominated, how much swing gas is needed, what the storage position is at the beginning of the month and what it should look like at the end of the month. The managers attending agree on the monthly plan, and the Vice President determines if the plan is adequate, if it is implemented as planned, and if the supplies are on tap to carry out the plan.

A further measure of performance is the Vice President's monitoring of the development of the annual winter plan. The managers are responsible for developing an achievable and logical plan based upon review of the annual pipeline contracts, evaluation of other pipeline availability, evaluation of overall capacity, where incremental storage might be obtained, and a detailed review of existing supply contracts – should they be renewed, or should the group go out for bid?

In summary, the Vice President is very involved in the activities of the gas planning, procurement and management functions, and through this involvement is able to effectively assess the overall performance of his Gas Operations Group, as well as the individual employees of the group.

Training

There is no formal training program, or training manual, for employees in the gas planning, procurement and management functions. Some informal cross-training is currently underway. For example, because of the asset management agreement with Mirant, as discussed in detail in Chapter 3, Task Area Three - Gas Supply Management, one of the gas buyers had time available and so was spending time in Gas Control learning about this operation.

The three managers whose activities are central to the gas planning, procurement and management functions are the Manager Gas Resources, Manager Gas Control, and the Manager Gas Rates & Transportation and have been with the Company 35 years, 32 years, and 34 years respectively. Considering the long tenure of each of these Managers, there is currently an organized effort underway to capture the knowledge of these individuals and ensure it is effectively retained in the organization and transferred to newer employees.

The Vice President, Gas Operations expressed some concern about the lack of “bench strength” in Gas Operations. As a result, a reorganization plan for Gas Operations was reported to be in development that would not add any FTEs (full time employee equivalents), but would increase the number of people that touch the activities and provide more opportunity for cross-training.

Job Descriptions

Job descriptions for employees involved in gas planning, procurement and management functions are current, and appropriately describe the activities and responsibilities for each of the positions in Gas Operations. Job descriptions are used to some extent in the performance measurement process, but as indicated above, the primary factors in measurement of performance are the KPI and AIP programs.

(2) Approval Authorities

Approval of activities within Gas Operations are controlled by a formal Cinergy decision matrix, or chart of approval authorities, that specifies the magnitude of commitment that various levels of management can make. These limits are specified in the Cinergy Authorized Approvals Manual.

Gas Operations does adhere to these approval authorities, and has recently been granted formal approval to modify them slightly in order to permit greater operational flexibility in the gas planning, procurement and management functions.

(3) Work Process Definition and Control

The operations of the gas planning, procurement and management functions are guided by, formalized, written policies and procedures that are current. In fact, in recognition of the critical nature of the responsibilities of the position of Supply Analyst, the procedures for this position are remarkably detailed and complete.

ULH&P is not required to file a cost allocation manual (CAM) with the Commission in that its revenue from non-regulated activities does not exceed the required threshold. Nevertheless, ULH&P has used the comprehensive CAM prepared by CG&E in its rate case filings, and uses this manual for its own cost allocation procedures.

Policies for dealing with affiliates are covered in the Cinergy Corporate Code of Conduct. All employees have received orientation on these procedures, and every employee has signed a statement of understanding regarding these procedures. This Code of Conduct was tailored to meet the specific requirements in Kentucky related to affiliated relations. The Gas Operations Group has never considered that there was any pressure of any kind to do business with an affiliate.

Cinergy has complete procedures covering Risk Management, entitled "Cinergy Corp. Amended and Restated Integrated Risk Management Policies". These procedures specify that each Risk Originating Unit has responsibility to develop its own more detailed procedures for handling risk management at the operating level. However, ULH&P is not a risk originating unit as defined in these corporate procedures; it only has regulatory risk, and therefore there is no requirement for risk management procedures.

(4) Documentation Requirements

Documentation of gas procurement and supply management activities within the Gas Resources Department is satisfactory, with the exception of not having a Strategic Plan as discussed below. As discussed above under the Section entitled *Performance Measurement*, the Vice President, Gas Operations maintains very close contact with the operations related to gas planning, procurement and management through the regularly scheduled meetings and reports that flow from these meetings.

The Vice President, Gas Operations keeps his superiors informed of what's going on through regular reports and meetings. He prepares a weekly written report for his immediate superior, the Vice President, Chief Operating Officer Regulated Businesses , and in addition, has a face-to-face meeting with him about every two weeks.

ULH&P does not have a Strategic Plan. Instead of having its own Strategic Plan, ULH&P uses the general guidance provided by the Strategic Plan prepared by CG&E. The CG&E Strategic Plan is typical of gas LDC documents of this nature, but it does not contain anything specifically relating to ULH&P.

(5) Auditing

There has not been an internal audit of ULH&P in the last 5 years.

Approximately mid-way through the current audit of ULH&P, Liberty was informed that ULH&P had initiated an internal audit of the gas procurement and management function to be conducted by PriceWaterhouseCoopers (PWC) and to be completed in approximately mid-2002. The audit will be managed by Internal Auditing at Cinergy, but actually conducted by PWC.

The Cinergy Vice President, Risk Management has conducted a risk assessment of gas procurement and management within ULH&P and has found no particular areas that concern him. Thus, PWC will not be given any particular areas into which they should focus the internal audit.

Future audit schedules for ULH&P will depend on what is found by PWC, but it is now planned that internal audits will be conducted regularly, at approximately 2 to 3 year intervals. Liberty has concerns that any future audit schedule might be based solely on the results of this PWC audit.

c. Conclusions

(1) The Gas Resources Department has done a good job of managing natural gas procurement with a limited staff, and of documenting the policies and procedures related to procurement and management of natural gas supplies.

The operations of the Gas Resources Department are conducted effectively with a limited staff, and guided by formalized, written policies and procedures that are current. Procedures used by the Department are lengthy and detailed, and are kept up to date as necessary by the individuals that use these procedures.

(2) The Gas Operations Group does not have the necessary formal training program to address the training requirements related to addition of new employees, cross-training, or departure of employees having significant knowledge of gas operations. (*Recommendation #1*)

Because the Gas Operations Group is staffed with many senior personnel who have considerable knowledge and experience relevant to the operations of ULH&P, the Group must take prompt steps to develop formal training programs that will enable proper training of new employees, cross-training of current employees, and provide for appropriate knowledge transfer when these employees of long tenure depart.

(3) Job descriptions for positions in the Gas Resources Department are current and effectively describe the positions to which they apply.

Job descriptions for employees of the Department are current, and appropriately describe the activities and responsibilities for each of the Department's positions.

(4) ULH&P does not have a Strategic Plan specific to its own operations. (*Recommendation #2*)

ULH&P does not have a Strategic Plan. Instead of having their own Strategic Plan, ULH&P uses the general guidance provided by the Strategic Plan prepared by CG&E. The CG&E Strategic Plan is typical of gas LDC documents of this nature, but it does not contain anything specifically relating to ULH&P.

(5) There has not been an internal audit of the gas planning, procurement and management functions within the last five years. (*Recommendations #3 & #4*)

It is unusual that an internal audit of the gas planning, procurement and management function at ULH&P has not been conducted within the last five years.

Although there has not been an internal audit of ULH&P in the last five years, ULH&P has indicated that an internal audit of the CG&E/ULH&P gas procurement and management function will be conducted by PriceWaterhouseCoopers (PWC) and completed in approximately mid-2002. Liberty feels it is appropriate for this audit to be conducted by PWC at this time since there have been no internal audits within the last five years. Further, ULH&P has indicated that future internal audit schedules will depend on what is found by PWC, and that future audits will be conducted regularly, at approximately 2 to 3 year intervals. Liberty has concerns that any future internal audit schedule might be based solely on the results of this PWC audit.

d. Recommendations

(1) Develop a formal training program for Gas Operations that will provide for training of new employees, cross-training of existing employees, and address the issue of losing significant gas knowledge base when an employee of long tenure leaves. (*Conclusion #2*)

Gas Operations should develop a comprehensive training program to serve as a guide for training new employees, and for providing cross-training to existing employees. ULH&P must be confident that a program is in place to provide for the ongoing knowledge transfer from the existing employees of long tenure with the Group to newer employees, such that mechanisms are in place to ensure continuity of knowledge and activities when these employees do leave Cinergy.

(2) Develop a Strategic Plan specific for the gas planning, procurement and management functions related to the operations of ULH&P. (*Conclusion #4*)

Utilities throughout the country have determined that regular preparation of strategic plans for the natural gas business is a sound way in which to effectively address the changing environment of the business and to continually keep senior management abreast of the issues facing their operations. In addition, another important value of strategic plans is that they provide information to the regulator by defining processes and actions.

Although CG&E and ULH&P's systems are integrated and the same group performs the gas procurement function for both companies, there are issues unique to ULH&P as well as issues that affect CG&E only. The Gas Operations Group of Cinergy must prepare a Strategic Plan that applies to the operations of ULH&P. While this plan may closely resemble CG&E's Strategic Plan, it also must specifically addresses the gas planning, procurement and management functions issues important to ULH&P.

(3) Provide a report on the findings of the internal audit conducted by PriceWaterhouseCoopers in mid-2002 related to natural gas procurement and management functions to the Commission as soon as the results are available. (*Conclusion #5*)

Utilities throughout the country have determined that regular internal auditing of functions that involve such significant dollar expenditures, such as natural gas procurement and management, is necessary on frequent and regular intervals.

Management of ULH&P, as well as the Commission, must be assured that discrepancies that could negatively impact Kentucky ratepayers of ULH&P do not exist in the gas planning, procurement and management function.

Therefore, as soon as the internal audit conducted by PriceWaterHouseCoopers is completed in approximately mid-2002, ULH&P should provide a summary report to the Commission of the findings related to natural gas procurement and management functions.

(4) Develop a plan for internal auditing of the Gas Resources Department based on a risk assessment analysis. (*Conclusion #5*)

Liberty feels that any schedules for internal auditing should be based on a risk assessment analysis, and not whether any discrepancies have been found in the past. Further, Liberty feels that such assessments should be made through objective tests that internal auditors apply to all the functions of a company. Cinergy should conduct such risk assessments and use the results of these assessments to establish the plan and schedule for conducting internal audits of the Gas Resources Department. Typical risk assessment analyses include factors such as a review of past internal audit findings, input from senior management as to particular issues that might be of concern to them, regular risk assessment evaluations by the Gas Resources Department, consultation with external auditors, and overall assessments by the Internal Audit Department of those areas of corporate operations presenting risk exposure to the corporation.

3. Gas Supply Management

a. Scope

This chapter addresses ULH&P's management of its gas supply resources. Topics addressed include the following:

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Renegotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management

b. Background

The gas distribution system owned by ULH&P's parent CG&E serves a unified area located on both sides of the Ohio River near Cincinnati. Because part of the area is in Ohio and part in Kentucky, the Companies' operations are broken into two units, CG&E and ULH&P, for administrative, financial-reporting and regulatory-compliance purposes. The physical aspects of the facilities owned by the two entities are operated in an integrated fashion, however.

The Companies' distribution system includes an integrated pipeline network throughout the downtown areas of Cincinnati and the adjacent cities on the Kentucky side, Covington and Newport. Company facilities, and the facilities of affiliate KO Transmission Corporation, also cross the river in several places within the network, allowing the distribution system in the central part of the Companies' service area to be operated on an integrated basis.

For ease of administration and regulatory compliance, the three gas distribution subsidiaries, CG&E, ULH&P and Lawrenceburg Gas Company (located in an adjacent area in southeastern Indiana), each has its own contracts for pipeline capacity and commodity gas supply. Solicitations for commodity supply are conducted together for all three companies, but individual contracts are signed for each company. The gas costs for the three are not commingled; measurement stations are located at each point where the Companies' facilities cross a State border, in order that each Company's gas accounts can be segregated.

Physical aspects of the Companies' facilities, and those of affiliate KO Transmission, and the locations of their respective load centers, are such that all of ULH&P's supply must come from the south on a peak day. CG&E takes some of its supply from the south also, but that supply is delivered via KO Transmission, rather than by displacement through ULH&P. KO Transmission is an interstate pipeline, subject to regulation by the FERC with respect to its rates and terms of service. It begins at an interconnection with Columbia Gulf Transmission in Kentucky, and terminates after crossing the river into Ohio. Both CG&E and ULH&P hold capacity contracts on KO Transmission, as do several large-volume industrial customers, and several marketers who provide gas to other intermediate- and smaller-sized customers in the Companies' service areas.

Under some circumstances, CG&E delivers gas to ULH&P, and vice versa. These services involve interstate commerce, so they are provided pursuant to FERC-approved rates. Each of the companies has a Service Agreement with the other for those occasions, and those Service Agreements reference the FERC-approved rate.

(1) Existing Gas Supply Portfolio

Until the early 1980s, CG&E/ULH&P was a full-requirements customer of Columbia Gas Transmission Corporation. As part of a "global" settlement among Columbia Transmission and its customers, CG&E/ULH&P obtained access to upstream pipelines that provided supply to Columbia Transmission. Those upstream pipelines included Columbia Transmission's upstream affiliate, Columbia Gulf Transmission, but also non-affiliates Texas Gas Transmission, Texas Eastern Transmission, and Tennessee Gas Pipeline. Moreover, as part of that settlement, Columbia Transmission agreed to sell an interest in some of its pipeline facilities to CG&E/ULH&P. Those facilities would provide a direct, physical connection to Columbia Gulf and Tennessee.

Columbia Transmission's parent filed for bankruptcy before the sale of the facilities interest could be completed. In 1994, however, the sale was consummated. At that time, CG&E put the facilities interest into a new subsidiary, KO (for Kentucky Ohio) Transmission. KO Transmission was subsequently expanded with additional facilities from Columbia Transmission, transferred on the same basis as before (net book cost), as part of the settlement of another Columbia Transmission rate case, FERC Docket No. RP95-408. In 1996, KO Transmission was tied into the Tennessee Gas Pipeline system, which KO crosses on the way from Columbia Gulf to CG&E/ULH&P's service area.

Going into the FERC Order 636 implementation process, ULH&P had contracts for sales service with Texas Gas and Columbia Transmission. It also had contracts for firm transportation service with Texas Gas and Tennessee Gas Pipeline (via KO Transmission), and for storage service with Columbia Transmission and ANR Pipeline. As a result of the 636 process, ULH&P's sales-service contracts with Columbia Transmission and Texas Gas were replaced with combinations of transportation and storage services on those systems. Table 3.1 below shows how the capacity portfolio has evolved:

Table 3.1 Evolution of ULH&P Capacity Portfolio
(Firm City-Gate Delivery Capacity, Dth/day)

Pipeline Service	**Before 636 Implementation**	**After 636 Implementation**	**2001–2002 Winter**
Sales Service			
Columbia Transmission	18,000		
Texas Gas	39,000		
Total Sales Service	57,000		
Firm Transportation			
Columbia Transmission		22,340	
Columbia Gulf/KO Transmission		22,340	22,538
Texas Gas	9,000	18,500	
Tennessee/KO Transmission	8,011	8,826	38,088
Total Firm Transportation	17,011	72,006	60,626
Storage Service			
a) No-Notice Service			
Columbia Transmission	35,000	51,186	46,656
Texas Gas		8,400	
b) Nominated Service			
ANR Pipeline	11,000	11,000	
Total Storage	46,000	70,586	46,656
Total Capacity at ULH&P City Gates	120,011	142,592	107,282

Since the time of 636 implementation, CG&E/ULH&P has taken advantage of its multiple pipeline connections (and the interconnection of its load centers) to improve its position. In late 2000, ULH&P's contracts with Texas Gas expired, and those contracts were not renewed. Similarly, ULH&P's contract for storage service on ANR was not renewed. Moreover, except for its contracts with Columbia Transmission and Columbia Gulf, which do not expire until October, 2004, CG&E/ULH&P has been able to buy firm capacity for only the five winter months, enabling the Company to use a combination of firm and interruptible transportation capacity to serve its load in the summer, and to fill storage.

CG&E/ULH&P's portfolio of gas-supply contracts is similar. Finding no advantage to longer-term contracts, the Company enters into firm contracts for base-load and swing supplies for the five winter months, plus a 25-day peaking service. These contracts are re-bid every year. The Company also operates a 20,200 Dth/day propane/air peaking plant, located at Erlanger, Kentucky. The Company relies on spot-market purchases for serving its summer-period load, and for storage-injection volumes. Table 3.2 below shows ULH&P's commodity contracts for the recently-completed winter heating season.

Table 3.2 Summary of Suppliers

	Supplier 1			Supplier 2	
	Firm Base	Firm Swing	25-day Peaking	Firm Base	Firm Swing
Nov-01	7,808	13,852		8,000	13,000
Dec-01	13,645	28,201	22,300	9,000	13,000
Jan-02	16,474	26,374	22,300	8,000	13,000
Feb-02	14,537	28,310	22,300	8,000	13,000
Mar-02	8,893	12,767		8,000	13,000

All volumes Dth/Day

CG&E/ULH&P also uses an asset manager. During 2001, the Company was approached by a gas marketing firm regarding management of the Company's contracts for pipeline and storage capacity, and for gas supply. After conducting a competition among similar firms, CG&E/ULH&P awarded an asset-management contract to the firm with the best bid.

Under the terms of the asset-management contract, CG&E/ULH&P reports its gas-supply requirements to the asset manager every day. The asset manager is responsible for delivering those requirements to CG&E/ULH&P's city gates; how the asset manager sources and delivers the gas to CG&E/ULH&P is at the discretion of the asset manager. CG&E/ULH&P performs its own "virtual" dispatch on a least-cost basis, however, and this virtual dispatch determines what the Company pays to the asset manager.

(2) Supplier Identification and Qualification

The Company reports that term gas suppliers are selected on the basis of 1) the supplier's ability to provide a reliable gas supply on the pipelines that serve ULH&P; 2) the supplier's ability to provide daily swing gas to help with ULH&P's temperature-sensitive load; and 3) the supplier's financial strength for meeting its contractual obligations to ULH&P. The Company reports concern about a dwindling number of potential suppliers due to mergers and acquisitions, financial failure, etc. The Company also reports concerns finding suppliers for "swing" service; *i.e.*, service that is reserved but not taken unless required. Finally, the Company reports that it has used seven different suppliers over the last five years.

CG&E/ULH&P has a general rule to spread the Companies' requirements among five suppliers. The Companies' request for proposals (RFP) for winter-period supplies for 2000/2001 went to six suppliers. Five suppliers were sent an RFP for peaking supplies. For 2001/2002, the five existing suppliers were sent RFPs for both term and peaking supplies.

The Companies' current list of spot gas suppliers includes ten companies. About half of these are producers and half of them are energy marketers. ULH&P solicits monthly from various suppliers that are deemed reliable and credit-worthy.

(3) Identification of Acquisition Needs

As discussed in Chapter 1, Gas Supply Planning, the Companies have a sophisticated set of processes for estimating their requirements for the next day, the next month and the next heating season. For the heating season, the Companies' Gas Resources Department gets base load and heating factors from the Load Forecasting Department. That information is combined with peak-day and annual weather information to estimate the Companies' requirements for base-load and swing supplies for each month of the heating season. Those estimates are used to prepare RFPs, which are issued in the spring (usually in May), for supplies to commence the following November.

A simplified version of the same process is used for each month of the non-heating season. Requirements estimates, including amounts required for storage injection, are prepared in the middle of the preceding month, and offers of spot-market supplies are sought toward the end of that preceding month. The best offers are accepted, and gas starts to flow. If needs within a month are greater or less than forecast, the Companies simply slow down or speed up storage injections correspondingly, ensuring that system requirements are met first. If indicated by price movements, or necessary to meet customer requirements, the Companies will go into the daily spot market for additional supply.

As suggested above, both CG&E and ULH&P came out of the 636 implementation process with more capacity than they felt was required for serving their loads. ULH&P has been shedding capacity as its long-term contracts expire, replacing it as necessary with winter-season-only capacity contracts, generally on Tennessee Gas Pipeline. Table 3.3 below summarizes the capacity turn-backs by ULH&P to date.

Table 3.3 ULH&P Capacity Contract Terminations
(contract quantities in Dth/day)

Effective Date	Contract MDQ	Pipeline	Contract Type
October 31, 1996	13,388	Columbia Gas Trans.	FTS
February 28, 1998	4,479	Tennessee	FT-A
March 31, 1998	8,952	Columbia Gas Trans.	FTS
March 31, 1998	6,000	Texas Gas Trans.	FT
August 31, 1998	8,959	Tennessee	FT-A
October 31, 2000	18,635	Texas Gas Trans.	NNS and FT

The total of the above turn-backs is 60,413 Dth/day. For comparison, ULH&P's design peak day for the 2001/2002 heating season was 154,475 Dth, including 20,200 Dth of on-system propane/air peaking.

The proportion of ULH&P's peak-day supply mix provided from storage is 30 percent. The Company's winter-season proportion from storage is 15 percent. While these proportions are low relative to the counterpart figures for the other LDCs studied for this project, ULH&P's evaluations suggest that additional storage is not cost-effective in the current environment.

In general, storage services are more expensive than an equivalent amount of firm transportation service. Thus, whether storage is cost-effective depends on whether, and by how much, gas purchased during the non-heating season is less costly than gas purchased during the heating season. ULH&P's analysis, done prior to its decision to relinquish NNS service on Texas Gas (which has a storage component) at the end of October, 2000, suggested that, while the summer-to-winter differential needed to be at least 30 cents per Dth to make storage cost-effective, the actual differential at that time was only 12.6 cents per Dth. In fact, in three of the eight years prior to the analysis, the summer price turned out to be higher than the succeeding winter price. Indeed, that pattern repeated itself in 2001/02. Thus, ULH&P has stuck with its five-month contracts for firm transportation on Tennessee Gas Pipeline, plus a contract peaking service, and acquiring IT storage service from Tennessee.

(4) Negotiation and Renegotiation of Contracts

ULH&P's load has been stable for the last few years. Also, ULH&P has found new options for delivery to its city gates, including five-month FT contracts on Tennessee, an interruptible storage service on Tennessee, and a delivered peaking service. Thus, as the Company's capacity contracts have expired, it has been able to compare the terms proposed for renewals to those new options.

To this point, as suggested by the table above listing the Company's capacity turn-backs, the terms for renewal have not been as favorable as those for the alternatives. Hence, the Company has elected to allow the contracts to expire, and to select the alternatives. The Company's contracts for pipeline and storage capacity on Columbia Transmission and Columbia Gulf Transmission are due to expire on October 31, 2004, and the Company is exploring options for replacement of these contracts.

As previously discussed, the Company has found no economic or operational reason to enter into gas supply contracts for more than a year. Thus, the Company's longest contracts for gas supply are for the next heating season. At any point in time, therefore, the Company's portfolio of supply contracts reflects market conditions that are quite current.

(5) Contract Terms and Conditions

ULH&P's contracts for pipeline and storage capacity are generally Service Agreements pursuant to FERC Gas Tariffs. Thus, while terms and conditions may be addressed in negotiations regarding rate cases and other FERC initiatives, they are generally not negotiated individually. CG&E and its subsidiaries participate in FERC proceedings that the Companies determine to be of significance, individually in some cases, and through customer groups in others.

As has been discussed previously, the Company buys considerable quantities of spot-market gas. A standard, Gas Industry Standards Board (GISB) contract is used for those purchases.

The Companies have had their own contract for base-load and swing quantities of gas supply. Those contracts have been modified through negotiations with suppliers over time, however. Arrangements for swing supplies, in particular, have often added a "keep-whole" feature, whereby the Company agrees to pay the supplier the difference between the contract price (generally a first-of-the-month index) and the price that the supplier gets selling the gas elsewhere in the event that the Company finds that it cannot take the gas. The "sale elsewhere" price is usually an established index, as well, but it is a daily one, rather than a monthly one. "Keep-whole" payments totaled $121,648 in 1999 and $109,814 in 2001, but only $408 in 2000.

The Company's contract for peaking service has features that are different from other supply contracts, but are common to contracts of this type. The Company pays a reservation fee for all of the days on which it might take the service, but pays the commodity cost only for the days on which it takes the service. If the service is nominated at all, however, the entire quantity must be taken.

The Companies' contracts with the asset manager are more complex. Access to the Companies' gas in storage and their pipeline capacity in the event of financial trouble on the part of the asset manager are contingencies that require special care. The Companies manage this contingency in two ways. This is first done through contract provisions that give them access to their pipeline and storage capacity in the event that the asset manager does not perform. This is also done through a letter of credit, to cover assets that are assigned to the manager, principally gas in storage. In the case of the current asset manager, ULH&P has a letter of credit covering the value of the gas in storage. As noted, ULH&P also has the ability to take its capacity and commodity contracts back, and only pays the asset manager after receiving the gas supply and service.

(6) Peak Period Performance

The Companies experienced no delivery failures for system supply during the winter of 2000-2001. Transportation-service customers experienced a supplier default in February 2001, but ULH&P was able to assist those customers, with system supply and system assets, while other suppliers were located.

(7) Price Risk Management

ULH&P examined some basic price-risk management strategies for use with system supply in the course of its participation in the KYPSC's Administrative Case No. 384. In March 2001, the Company filed a report (which had been requested of each of the Kentucky LDCs by the Commission) discussing its efforts at mitigating higher gas prices to that point.

The March Report presented some discussion of the Company's effort to reduce costs through turning back un-needed pipeline and storage capacity, and of its strategies for commodity purchasing. The March Report also presented an analysis that the Company had performed regarding possible benefits of three "hedging" strategies, namely, 1) increasing the amount of gas in storage, 2) fixing winter-period prices through suppliers, and 3) a combination of those two strategies. The Company's analysis suggested that none of the three strategies made much difference to the average price that might be expected, but that all three would have the effect of limiting the likely variation in the price, or limiting "volatility". The analysis also suggested that, while not reducing materially the expected gas cost, the second option, fixing the price through suppliers for the forthcoming winter, had the best chance of resulting in a lower average price. In all cases, the chance of a lower average price was considerably less than 50 percent, however.

On the basis of that analysis, and on the Company's belief that the Commission was interested in testing hedging through pilot programs, the Company proposed a pilot program. The proposed program was to be for two heating seasons, 2001-2002 and 2002-2003, and was to consist of "…fixed-price contracts, cost-averaging instruments based on the NYMEX strip price for a given period of time, price caps and no-cost collars." The Commission approved the Company's proposal with some modifications.

On the basis of that approval, the Company entered into the following transactions:

Table 3.4 Winter 2001-2002 Hedging Volumes

Strike Date	Supplier	Type	Delivery Point	Volume Dth/Day	Month(s)	Total Volume
12/6/2000	A	Fixed	HH	1,700	Nov	51,000
12/6/2000	A	Fixed	HH	1,700	Dec & Jan	105,400
5/11/2001	B	Fixed	HH	1,700	Dec	52,700
7/18/2001	A	Cost Avg.	HH	5,000	Nov - Mar	755,000
8/27/2001	A	Collar	CGT	1,540	Jan	47,740
8/27/2001	A	Collar	CGT	2,277	Feb	63,756
9/7/2001	B	Collar	HH	2,000	Nov - Mar	302,000
10/9/2001	B	Collar	CGT	2,000	Dec - Feb	180,000
						1,557,596

HH = Henry Hub
CGT = Columbia Gulf So. LA Onshore

The Company reported that it incurred no costs for any of these hedges; rather, it paid the hedged price to its suppliers when the gas was delivered. The total amount hedged represented 50.4 percent of the Company's expected purchases of base-load gas for the 2000-2001 heating season.

The Interim Report also reported on the Company's decision process for placing the hedges. The Vice President of Gas Operations, the Manager of Gas Resources and members of the Manager's staff met weekly to discuss market conditions for natural gas, short- and long-term weather forecasts, gas-industry trade publications and price trends, to decide when and whether to enter into these transactions. Brief summaries of each decision were made; those summaries, and the information packets considered by the participants at each decision point, were filed with the Commission.

The results of the Company's 2001-2002 program were similar to the experiences of Western Kentucky Gas. As market prices declined after the beginning of the heating season, the hedged prices paid by ULH&P, and by Western, turned out to be higher than market prices. The Company reported that its gas costs for the heating season turned out to be $1.2 million, or 10 cents per Mcf, higher than they would have been if no hedging had been conducted.

In March 2002, the Company filed its proposed hedging plan for the 2002-2003 heating season. The new plan was largely the same as the previous one, except for the elimination of price caps, and except for reducing the volumes to be hedged. The Commission approved the Company's plan, subject to the modification that there be no lower limit on the volumes hedged.

c. Conclusions

(1) ULH&P has been aggressive in shaping its capacity portfolio to fit its load profile.

The table at the beginning of this chapter speaks for itself about ULH&P's reductions in its capacity contracts. Those reductions have come as the Company's contracts have expired, and as alternatives, such as contract peaking services, interruptible storage services and seasonal contracts for firm transportation capacity, have become available.

The Company's aggressiveness in this area can be seen in its gas costs. As of March 2002, the Company's volumetric rate for small-volume customers was the lowest of the five LDCs examined as part of this study.

(2) CG&E/ULH&P's direct connections to upstream pipelines have not only lowered near-term supply costs, but have added bargaining leverage and sourcing flexibility that should continue to yield continuing savings.

The Companies' physical connection to five interstate pipelines, Columbia Gas Transmission, Columbia Gulf Transmission, Tennessee Gas Pipeline, Texas Eastern Transmission and Texas Gas Transmission, plus easy access to a sixth, ANR Pipeline Company, not only provides considerable bargaining leverage for negotiations for pipeline services, but also provides an extra measure of supply security. The Companies' greater diversity in pipeline connections affords additional supply security in that they have more gas-sourcing options in the event of some kind of supply disruption.

(3) CG&E/ULH&P's interconnection behind its city gates is also a factor in reducing its gas costs.

Interconnection is part of the Companies' bargaining power in that it allows them to shift their loads among the pipelines in response to developments in commodity and capacity costs. Access to multiple pipelines, and the flexibility to shift load among them, also provides an extra dimension of value for an external asset manager. Asset-management fees are producing a welcome offset to the capacity costs required to be borne by the Company's system-supply customers.

(4) The Company is continuing to work on reducing its capacity costs.

The Companies' Columbia contracts expire at the end of October 2004. They have already begun exploring options for the services currently purchased from Columbia.

(5) CG&E/ULH&P is appropriately concerned about a decline in the number of viable natural gas suppliers. *(Recommendation #1)*

Consolidation has been a factor in reducing the number of viable natural gas suppliers. The well-publicized financial problems of the marketing segment of the energy industry are also having its negative impact on the base of candidate gas suppliers. ULH&P has had a supplier decline to bid because of the small size of the supply package being offered.

(6) As with the other Kentucky LDCs that had hedging programs in '01/'02, ULH&P's hedging program increased costs last winter. *(Recommendation #2)*

Gas prices declined after the heating season began, which resulted in hedged prices coming in above market prices for those Kentucky LDCs that were involved in hedging programs.

d. Recommendations

(1) CG&E/ULH&P should increase its efforts to find additional potential natural gas suppliers. *(Conclusion #5)*

CG&E/ULH&P represents a relatively large market, and an attractive package of physical assets. In the time remaining under the Companies' current asset-management contract, the Companies need to discuss with potential suppliers and asset managers what options and strategies they might use to ensure that there is vigorous competition for their markets.

(2) ULH&P should work with the Commission and the other Kentucky LDCs to establish a common foundation of objectives for natural gas hedging programs. *(Conclusion #6)*

As discussed in the first section of this report, Liberty believes that the Commission, the LDCs and other interested parties should pause after next winter to review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. Also, Atmos used different hedging techniques in other States in which it operates. The Columbia Distribution Companies, whose gas-supply operations are also conducted on a centralized basis, had hedging programs in three of the five States in which they operate. Kentucky is one of the five, but not one of the three. Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management.

Liberty recommends that a specific area for discussion be the objectives of future hedging programs. In this vein, Liberty applauds the Commission's adoption of the Attorney General's suggestion, presented in the context of consideration of ULH&P's proposed hedging program for '02/'03, that public input be sought in selecting those objectives. Our experience tells us that different customer classes will prefer different objectives. That knowledge will help the Kentucky LDCs to tailor their service offerings more closely to their customers' requirements.

3. Gas Supply Management

a. Scope

This chapter addresses ULH&P's management of its gas supply resources. Topics addressed include the following:

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Renegotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management

b. Background

The gas distribution system owned by ULH&P's parent CG&E serves a unified area located on both sides of the Ohio River near Cincinnati. Because part of the area is in Ohio and part in Kentucky, the Companies' operations are broken into two units, CG&E and ULH&P, for administrative, financial-reporting and regulatory-compliance purposes. The physical aspects of the facilities owned by the two entities are operated in an integrated fashion, however.

The Companies' distribution system includes an integrated pipeline network throughout the downtown areas of Cincinnati and the adjacent cities on the Kentucky side, Covington and Newport. Company facilities, and the facilities of affiliate KO Transmission Corporation, also cross the river in several places within the network, allowing the distribution system in the central part of the Companies' service area to be operated on an integrated basis.

For ease of administration and regulatory compliance, the three gas distribution subsidiaries, CG&E, ULH&P and Lawrenceburg Gas Company (located in an adjacent area in southeastern Indiana), each has its own contracts for pipeline capacity and commodity gas supply. Solicitations for commodity supply are conducted together for all three companies, but individual contracts are signed for each company. The gas costs for the three are not commingled; measurement stations are located at each point where the Companies' facilities cross a State border, in order that each Company's gas accounts can be segregated.

Physical aspects of the Companies' facilities, and those of affiliate KO Transmission, and the locations of their respective load centers, are such that all of ULH&P's supply must come from the south on a peak day. CG&E takes some of its supply from the south also, but that supply is delivered via KO Transmission, rather than by displacement through ULH&P. KO Transmission is an interstate pipeline, subject to regulation by the FERC with respect to its rates and terms of service. It begins at an interconnection with Columbia Gulf Transmission in Kentucky, and terminates after crossing the river into Ohio. Both CG&E and ULH&P hold capacity contracts on KO Transmission, as do several large-volume industrial customers, and several marketers who provide gas to other intermediate- and smaller-sized customers in the Companies' service areas.

Under some circumstances, CG&E delivers gas to ULH&P, and vice versa. These services involve interstate commerce, so they are provided pursuant to FERC-approved rates. Each of the companies has a Service Agreement with the other for those occasions, and those Service Agreements reference the FERC-approved rate.

(1) Existing Gas Supply Portfolio

Until the early 1980s, CG&E/ULH&P was a full-requirements customer of Columbia Gas Transmission Corporation. As part of a "global" settlement among Columbia Transmission and its customers, CG&E/ULH&P obtained access to upstream pipelines that provided supply to Columbia Transmission. Those upstream pipelines included Columbia Transmission's upstream affiliate, Columbia Gulf Transmission, but also non-affiliates Texas Gas Transmission, Texas Eastern Transmission, and Tennessee Gas Pipeline. Moreover, as part of that settlement, Columbia Transmission agreed to sell an interest in some of its pipeline facilities to CG&E/ULH&P. Those facilities would provide a direct, physical connection to Columbia Gulf and Tennessee.

Columbia Transmission's parent filed for bankruptcy before the sale of the facilities interest could be completed. In 1994, however, the sale was consummated. At that time, CG&E put the facilities interest into a new subsidiary, KO (for Kentucky Ohio) Transmission. KO Transmission was subsequently expanded with additional facilities from Columbia Transmission, transferred on the same basis as before (net book cost), as part of the settlement of another Columbia Transmission rate case, FERC Docket No. RP95-408. In 1996, KO Transmission was tied into the Tennessee Gas Pipeline system, which KO crosses on the way from Columbia Gulf to CG&E/ULH&P's service area.

Going into the FERC Order 636 implementation process, ULH&P had contracts for sales service with Texas Gas and Columbia Transmission. It also had contracts for firm transportation service with Texas Gas and Tennessee Gas Pipeline (via KO Transmission), and for storage service with Columbia Transmission and ANR Pipeline. As a result of the 636 process, ULH&P's sales-service contracts with Columbia Transmission and Texas Gas were replaced with combinations of transportation and storage services on those systems. Table 3.1 below shows how the capacity portfolio has evolved:

Table 3.1 Evolution of ULH&P Capacity Portfolio
(Firm City-Gate Delivery Capacity, Dth/day)

Pipeline Service	Before 636 Implementation	After 636 Implementation	2001–2002 Winter
Sales Service			
Columbia Transmission	18,000		
Texas Gas	39,000		
Total Sales Service	57,000		
Firm Transportation			
Columbia Transmission		22,340	
Columbia Gulf/KO Transmission		22,340	22,538
Texas Gas	9,000	18,500	
Tennessee/KO Transmission	8,011	8,826	38,088
Total Firm Transportation	17,011	72,006	60,626
Storage Service			
a) No-Notice Service			
Columbia Transmission	35,000	51,186	46,656
Texas Gas		8,400	
b) Nominated Service			
ANR Pipeline	11,000	11,000	
Total Storage	46,000	70,586	46,656
Total Capacity at ULH&P City Gates	120,011	142,592	107,282

Since the time of 636 implementation, CG&E/ULH&P has taken advantage of its multiple pipeline connections (and the interconnection of its load centers) to improve its position. In late 2000, ULH&P's contracts with Texas Gas expired, and those contracts were not renewed. Similarly, ULH&P's contract for storage service on ANR was not renewed. Moreover, except for its contracts with Columbia Transmission and Columbia Gulf, which do not expire until October, 2004, CG&E/ULH&P has been able to buy firm capacity for only the five winter months, enabling the Company to use a combination of firm and interruptible transportation capacity to serve its load in the summer, and to fill storage.

CG&E/ULH&P's portfolio of gas-supply contracts is similar. Finding no advantage to longer-term contracts, the Company enters into firm contracts for base-load and swing supplies for the five winter months, plus a 25-day peaking service. These contracts are re-bid every year. The Company also operates a 20,200 Dth/day propane/air peaking plant, located at Erlanger, Kentucky. The Company relies on spot-market purchases for serving its summer-period load, and for storage-injection volumes. Table 3.2 below shows ULH&P's commodity contracts for the recently-completed winter heating season.

Table 3.2 Summary of Suppliers

	Supplier 1			Supplier 2	
	Firm Base	Firm Swing	25-day Peaking	Firm Base	Firm Swing
Nov-01	7,808	13,852		8,000	13,000
Dec-01	13,645	28,201	22,300	9,000	13,000
Jan-02	16,474	26,374	22,300	8,000	13,000
Feb-02	14,537	28,310	22,300	8,000	13,000
Mar-02	8,893	12,767		8,000	13,000

All volumes Dth/Day

CG&E/ULH&P also uses an asset manager. During 2001, the Company was approached by a gas marketing firm regarding management of the Company's contracts for pipeline and storage capacity, and for gas supply. After conducting a competition among similar firms, CG&E/ULH&P awarded an asset-management contract to the firm with the best bid.

Under the terms of the asset-management contract, CG&E/ULH&P reports its gas-supply requirements to the asset manager every day. The asset manager is responsible for delivering those requirements to CG&E/ULH&P's city gates; how the asset manager sources and delivers the gas to CG&E/ULH&P is at the discretion of the asset manager. CG&E/ULH&P performs its own "virtual" dispatch on a least-cost basis, however, and this virtual dispatch determines what the Company pays to the asset manager.

(2) Supplier Identification and Qualification

The Company reports that term gas suppliers are selected on the basis of 1) the supplier's ability to provide a reliable gas supply on the pipelines that serve ULH&P; 2) the supplier's ability to provide daily swing gas to help with ULH&P's temperature-sensitive load; and 3) the supplier's financial strength for meeting its contractual obligations to ULH&P. The Company reports concern about a dwindling number of potential suppliers due to mergers and acquisitions, financial failure, etc. The Company also reports concerns finding suppliers for "swing" service; *i.e.*, service that is reserved but not taken unless required. Finally, the Company reports that it has used seven different suppliers over the last five years.

CG&E/ULH&P has a general rule to spread the Companies' requirements among five suppliers. The Companies' request for proposals (RFP) for winter-period supplies for 2000/2001 went to six suppliers. Five suppliers were sent an RFP for peaking supplies. For 2001/2002, the five existing suppliers were sent RFPs for both term and peaking supplies.

The Companies' current list of spot gas suppliers includes ten companies. About half of these are producers and half of them are energy marketers. ULH&P solicits monthly from various suppliers that are deemed reliable and credit-worthy.

(3) Identification of Acquisition Needs

As discussed in Chapter 1, Gas Supply Planning, the Companies have a sophisticated set of processes for estimating their requirements for the next day, the next month and the next heating season. For the heating season, the Companies' Gas Resources Department gets base load and heating factors from the Load Forecasting Department. That information is combined with peak-day and annual weather information to estimate the Companies' requirements for base-load and swing supplies for each month of the heating season. Those estimates are used to prepare RFPs, which are issued in the spring (usually in May), for supplies to commence the following November.

A simplified version of the same process is used for each month of the non-heating season. Requirements estimates, including amounts required for storage injection, are prepared in the middle of the preceding month, and offers of spot-market supplies are sought toward the end of that preceding month. The best offers are accepted, and gas starts to flow. If needs within a month are greater or less than forecast, the Companies simply slow down or speed up storage injections correspondingly, ensuring that system requirements are met first. If indicated by price movements, or necessary to meet customer requirements, the Companies will go into the daily spot market for additional supply.

As suggested above, both CG&E and ULH&P came out of the 636 implementation process with more capacity than they felt was required for serving their loads. ULH&P has been shedding capacity as its long-term contracts expire, replacing it as necessary with winter-season-only capacity contracts, generally on Tennessee Gas Pipeline. Table 3.3 below summarizes the capacity turn-backs by ULH&P to date.

Table 3.3 ULH&P Capacity Contract Terminations
(contract quantities in Dth/day)

Effective Date	Contract MDQ	Pipeline	Contract Type
October 31, 1996	13,388	Columbia Gas Trans.	FTS
February 28, 1998	4,479	Tennessee	FT-A
March 31, 1998	8,952	Columbia Gas Trans.	FTS
March 31, 1998	6,000	Texas Gas Trans.	FT
August 31, 1998	8,959	Tennessee	FT-A
October 31, 2000	18,635	Texas Gas Trans.	NNS and FT

The total of the above turn-backs is 60,413 Dth/day. For comparison, ULH&P's design peak day for the 2001/2002 heating season was 154,475 Dth, including 20,200 Dth of on-system propane/air peaking.

The proportion of ULH&P's peak-day supply mix provided from storage is 30 percent. The Company's winter-season proportion from storage is 15 percent. While these proportions are low relative to the counterpart figures for the other LDCs studied for this project, ULH&P's evaluations suggest that additional storage is not cost-effective in the current environment.

In general, storage services are more expensive than an equivalent amount of firm transportation service. Thus, whether storage is cost-effective depends on whether, and by how much, gas purchased during the non-heating season is less costly than gas purchased during the heating season. ULH&P's analysis, done prior to its decision to relinquish NNS service on Texas Gas (which has a storage component) at the end of October, 2000, suggested that, while the summer-to-winter differential needed to be at least 30 cents per Dth to make storage cost-effective, the actual differential at that time was only 12.6 cents per Dth. In fact, in three of the eight years prior to the analysis, the summer price turned out to be higher than the succeeding winter price. Indeed, that pattern repeated itself in 2001/02. Thus, ULH&P has stuck with its five-month contracts for firm transportation on Tennessee Gas Pipeline, plus a contract peaking service, and acquiring IT storage service from Tennessee.

(4) Negotiation and Renegotiation of Contracts

ULH&P's load has been stable for the last few years. Also, ULH&P has found new options for delivery to its city gates, including five-month FT contracts on Tennessee, an interruptible storage service on Tennessee, and a delivered peaking service. Thus, as the Company's capacity contracts have expired, it has been able to compare the terms proposed for renewals to those new options.

To this point, as suggested by the table above listing the Company's capacity turn-backs, the terms for renewal have not been as favorable as those for the alternatives. Hence, the Company has elected to allow the contracts to expire, and to select the alternatives. The Company's contracts for pipeline and storage capacity on Columbia Transmission and Columbia Gulf Transmission are due to expire on October 31, 2004, and the Company is exploring options for replacement of these contracts.

As previously discussed, the Company has found no economic or operational reason to enter into gas supply contracts for more than a year. Thus, the Company's longest contracts for gas supply are for the next heating season. At any point in time, therefore, the Company's portfolio of supply contracts reflects market conditions that are quite current.

(5) Contract Terms and Conditions

ULH&P's contracts for pipeline and storage capacity are generally Service Agreements pursuant to FERC Gas Tariffs. Thus, while terms and conditions may be addressed in negotiations regarding rate cases and other FERC initiatives, they are generally not negotiated individually. CG&E and its subsidiaries participate in FERC proceedings that the Companies determine to be of significance, individually in some cases, and through customer groups in others.

As has been discussed previously, the Company buys considerable quantities of spot-market gas. A standard, Gas Industry Standards Board (GISB) contract is used for those purchases.

The Companies have had their own contract for base-load and swing quantities of gas supply. Those contracts have been modified through negotiations with suppliers over time, however. Arrangements for swing supplies, in particular, have often added a "keep-whole" feature, whereby the Company agrees to pay the supplier the difference between the contract price (generally a first-of-the-month index) and the price that the supplier gets selling the gas elsewhere in the event that the Company finds that it cannot take the gas. The "sale elsewhere" price is usually an established index, as well, but it is a daily one, rather than a monthly one. "Keep-whole" payments totaled $121,648 in 1999 and $109,814 in 2001, but only $408 in 2000.

The Company's contract for peaking service has features that are different from other supply contracts, but are common to contracts of this type. The Company pays a reservation fee for all of the days on which it might take the service, but pays the commodity cost only for the days on which it takes the service. If the service is nominated at all, however, the entire quantity must be taken.

The Companies' contracts with the asset manager are more complex. Access to the Companies' gas in storage and their pipeline capacity in the event of financial trouble on the part of the asset manager are contingencies that require special care. The Companies manage this contingency in two ways. This is first done through contract provisions that give them access to their pipeline and storage capacity in the event that the asset manager does not perform. This is also done through a letter of credit, to cover assets that are assigned to the manager, principally gas in storage. In the case of the current asset manager, ULH&P has a letter of credit covering the value of the gas in storage. As noted, ULH&P also has the ability to take its capacity and commodity contracts back, and only pays the asset manager after receiving the gas supply and service.

(6) Peak Period Performance

The Companies experienced no delivery failures for system supply during the winter of 2000-2001. Transportation-service customers experienced a supplier default in February 2001, but ULH&P was able to assist those customers, with system supply and system assets, while other suppliers were located.

(7) Price Risk Management

ULH&P examined some basic price-risk management strategies for use with system supply in the course of its participation in the KYPSC's Administrative Case No. 384. In March 2001, the Company filed a report (which had been requested of each of the Kentucky LDCs by the Commission) discussing its efforts at mitigating higher gas prices to that point.

The March Report presented some discussion of the Company's effort to reduce costs through turning back un-needed pipeline and storage capacity, and of its strategies for commodity purchasing. The March Report also presented an analysis that the Company had performed regarding possible benefits of three "hedging" strategies, namely, 1) increasing the amount of gas in storage, 2) fixing winter-period prices through suppliers, and 3) a combination of those two strategies. The Company's analysis suggested that none of the three strategies made much difference to the average price that might be expected, but that all three would have the effect of limiting the likely variation in the price, or limiting "volatility". The analysis also suggested that, while not reducing materially the expected gas cost, the second option, fixing the price through suppliers for the forthcoming winter, had the best chance of resulting in a lower average price. In all cases, the chance of a lower average price was considerably less than 50 percent, however.

On the basis of that analysis, and on the Company's belief that the Commission was interested in testing hedging through pilot programs, the Company proposed a pilot program. The proposed program was to be for two heating seasons, 2001-2002 and 2002-2003, and was to consist of "…fixed-price contracts, cost-averaging instruments based on the NYMEX strip price for a given period of time, price caps and no-cost collars." The Commission approved the Company's proposal with some modifications.

On the basis of that approval, the Company entered into the following transactions:

Table 3.4 Winter 2001-2002 Hedging Volumes

Strike Date	Supplier	Type	Delivery Point	Volume Dth/Day	Month(s)	Total Volume
12/6/2000	A	Fixed	HH	1,700	Nov	51,000
12/6/2000	A	Fixed	HH	1,700	Dec & Jan	105,400
5/11/2001	B	Fixed	HH	1,700	Dec	52,700
7/18/2001	A	Cost Avg.	HH	5,000	Nov - Mar	755,000
8/27/2001	A	Collar	CGT	1,540	Jan	47,740
8/27/2001	A	Collar	CGT	2,277	Feb	63,756
9/7/2001	B	Collar	HH	2,000	Nov - Mar	302,000
10/9/2001	B	Collar	CGT	2,000	Dec - Feb	180,000
						1,557,596

HH = Henry Hub
CGT = Columbia Gulf So. LA Onshore

The Company reported that it incurred no costs for any of these hedges; rather, it paid the hedged price to its suppliers when the gas was delivered. The total amount hedged represented 50.4 percent of the Company's expected purchases of base-load gas for the 2000-2001 heating season.

The Interim Report also reported on the Company's decision process for placing the hedges. The Vice President of Gas Operations, the Manager of Gas Resources and members of the Manager's staff met weekly to discuss market conditions for natural gas, short- and long-term weather forecasts, gas-industry trade publications and price trends, to decide when and whether to enter into these transactions. Brief summaries of each decision were made; those summaries, and the information packets considered by the participants at each decision point, were filed with the Commission.

The results of the Company's 2001-2002 program were similar to the experiences of Western Kentucky Gas. As market prices declined after the beginning of the heating season, the hedged prices paid by ULH&P, and by Western, turned out to be higher than market prices. The Company reported that its gas costs for the heating season turned out to be $1.2 million, or 10 cents per Mcf, higher than they would have been if no hedging had been conducted.

In March 2002, the Company filed its proposed hedging plan for the 2002-2003 heating season. The new plan was largely the same as the previous one, except for the elimination of price caps, and except for reducing the volumes to be hedged. The Commission approved the Company's plan, subject to the modification that there be no lower limit on the volumes hedged.

c. Conclusions

(1) ULH&P has been aggressive in shaping its capacity portfolio to fit its load profile.

The table at the beginning of this chapter speaks for itself about ULH&P's reductions in its capacity contracts. Those reductions have come as the Company's contracts have expired, and as alternatives, such as contract peaking services, interruptible storage services and seasonal contracts for firm transportation capacity, have become available.

The Company's aggressiveness in this area can be seen in its gas costs. As of March 2002, the Company's volumetric rate for small-volume customers was the lowest of the five LDCs examined as part of this study.

(2) CG&E/ULH&P's direct connections to upstream pipelines have not only lowered near-term supply costs, but have added bargaining leverage and sourcing flexibility that should continue to yield continuing savings.

The Companies' physical connection to five interstate pipelines, Columbia Gas Transmission, Columbia Gulf Transmission, Tennessee Gas Pipeline, Texas Eastern Transmission and Texas Gas Transmission, plus easy access to a sixth, ANR Pipeline Company, not only provides considerable bargaining leverage for negotiations for pipeline services, but also provides an extra measure of supply security. The Companies' greater diversity in pipeline connections affords additional supply security in that they have more gas-sourcing options in the event of some kind of supply disruption.

(3) CG&E/ULH&P's interconnection behind its city gates is also a factor in reducing its gas costs.

Interconnection is part of the Companies' bargaining power in that it allows them to shift their loads among the pipelines in response to developments in commodity and capacity costs. Access to multiple pipelines, and the flexibility to shift load among them, also provides an extra dimension of value for an external asset manager. Asset-management fees are producing a welcome offset to the capacity costs required to be borne by the Company's system-supply customers.

(4) The Company is continuing to work on reducing its capacity costs.

The Companies' Columbia contracts expire at the end of October 2004. They have already begun exploring options for the services currently purchased from Columbia.

(5) CG&E/ULH&P is appropriately concerned about a decline in the number of viable natural gas suppliers. *(Recommendation #1)*

Consolidation has been a factor in reducing the number of viable natural gas suppliers. The well-publicized financial problems of the marketing segment of the energy industry are also having its negative impact on the base of candidate gas suppliers. ULH&P has had a supplier decline to bid because of the small size of the supply package being offered.

(6) As with the other Kentucky LDCs that had hedging programs in '01/'02, ULH&P's hedging program increased costs last winter. *(Recommendation #2)*

Gas prices declined after the heating season began, which resulted in hedged prices coming in above market prices for those Kentucky LDCs that were involved in hedging programs.

d. Recommendations

(1) CG&E/ULH&P should increase its efforts to find additional potential natural gas suppliers. *(Conclusion #5)*

CG&E/ULH&P represents a relatively large market, and an attractive package of physical assets. In the time remaining under the Companies' current asset-management contract, the Companies need to discuss with potential suppliers and asset managers what options and strategies they might use to ensure that there is vigorous competition for their markets.

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As discussed in the first section of this report, Liberty believes that the Commission, the LDCs and other interested parties should pause after next winter to review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. Also, Atmos used different hedging techniques in other States in which it operates. The Columbia Distribution Companies, whose gas-supply operations are also conducted on a centralized basis, had hedging programs in three of the five States in which they operate. Kentucky is one of the five, but not one of the three. Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management.

Liberty recommends that a specific area for discussion be the objectives of future hedging programs. In this vein, Liberty applauds the Commission's adoption of the Attorney General's suggestion, presented in the context of consideration of ULH&P's proposed hedging program for '02/'03, that public input be sought in selecting those objectives. Our experience tells us that different customer classes will prefer different objectives. That knowledge will help the Kentucky LDCs to tailor their service offerings more closely to their customers' requirements.

4. Gas Transportation

a. Scope

This chapter addresses ULH&P's programs for transportation of customer-owned gas. Topics considered include the following:

- Transportation Programs Offered
- Agency Programs
- Bypass Issues
- "Prodigal Son" Customers.

b. Background

(1) Transportation Programs Offered

ULH&P has recently revised its transportation services. Before the revisions, transportation-service customers, both firm and interruptible, were individually responsible for balancing their daily and monthly supplies with their usage. Since the changes have been made, suppliers now take responsibility for balancing their customers' supplies with usage on a pooled basis.

To facilitate the pooled balancing, the Company has added a new Interruptible Monthly Balancing Service, Rate IMBS. With this service, pool operators (suppliers) have a general obligation to balance pool usage with pool supplies on a daily basis, but they can select over-run tolerances for carrying excess deliveries into a succeeding month. Customers are charged a per Mcf rate on all throughput. This rate varies based on the tolerance level that the customer and pool operator selects; a smaller over-run tolerance has lower per Mcf charges. Under-deliveries, after taking into account any carry-over from the prior month, are "cashed out" at a first-of-the-month index for the month following the delivery month, plus pipeline commodity transportation charges and fuel. When operational flow orders (OFOs) have been issued, daily balancing resumes, although balancing is evaluated on a pooled basis, rather than customer by customer.

The Company also offers a Gas Trading Service (GTS), for use by pool operators to facilitate balancing their supplies with their customers' usage. The Company maintains an electronic bulletin board (EBB) for gas delivered into its distribution system. Participating pool operators can use the EBB to post notice for available supplies, or requirements for supply. Other participating pool operators can use those postings to buy or sell gas supplies as necessary to balance their pools. The charge for each transaction is $5.00, billed to the receiving party.

The Company's newly revised transportation services are available to customers whose usage exceeds certain minimums. These minimums are 10,000 Ccf per month (during the summer months, April through October) for Interruptible Transportation Service (Rate IT), and 20,000 Ccf per year (2,000 Mcf per year) for Firm Transportation Service (Rate FT-L). Transportation customers must also become a member of a pool (IT customers may sign up as a pool operator themselves), and subscribe to the Company's balancing service (Rate IMBS). Interruptible customers join pools under Rate AS, Pooling Service for Interruptible Transportation, and firm-service customers join pools under Rate FRAS, Firm Requirements Aggregation Service.

The pooling services are administrative vehicles for tracking the performance of pool operators. The usages of all pool members are combined into a total usage number for the pool, and that number is matched against the pool operator's total deliveries to ULH&P. Pool operators enter into a Large Volume Customer Transportation Pooling Agreement with the Company. That Agreement commits the pool operator to its balancing obligations, including the requirement to comply with OFOs, and to the balancing service rates and cash-out provisions that apply to its pool. There are no charges for joining a pool, but all charges and gas imbalances must be settled before pools are disbanded.

Suppliers providing gas to firm-service customers are evaluated by the Company "… to ensure that [they] possess the financial resources, experience, and reputation for satisfactory service that will enable [them] to perform [their] responsibilities as Supplier[s] in the program." Suppliers that do not meet the Company's financial standards are required to provide additional security, such as a letter of credit, a cash deposit, or other appropriate guarantee.

Both firm and interruptible transportation-service customers provide their own pipeline capacity, generally through their suppliers. The Company will supply gas temporarily, on a "best-efforts" basis, to firm-service customers whose supplier fails to perform, but no pipeline or storage capacity is reserved in order to be able to provide this service. Interruptible-service customers that serve "human needs and public welfare" – *e.g.*, hospitals, nursing homes, correctional institutions, etc. – must contract for a stand-by sales service, or have alternate-fuel capability.

Once customers' gas is delivered to the Company's city gates, both firm and interruptible transportation services on the Company's system are provided by displacement, rather than by point-to-point delivery. For both firm and interruptible transportation services, the Company may designate the city-gate receipt points where the customer's pool operator is required to deliver its gas. Transportation-service customers provide their proportionate share of lost-and-unaccounted-for volumes (LAUF).

Firm transportation service is subject to curtailment in times of system emergency, if curtailment is necessary to maintain service to the Company's sales-service customers. Interruptible-service customers can be interrupted as necessary to maintain firm transportation service, as well as sales services.

Both firm and interruptible transportation services require remote meter-reading equipment on the customer's meter, in order that the Company might monitor the customer's usage continuously. Metering data is available on the Company's EBB to assist pool managers in managing their supplies.

Table 4.1 below gives the number of customers and volumes transported for the Company's transportation services over the last three years. Large but temporary increases in the number of customers in the first few months of 2001 reflect supplier defaults. The Company counts each change of supplier, including temporary switches to agency service from the Company, as a new service (new customer).

Table 4.1 Transportation Customers & Volumes

	IT		FT-Commercial		FT-OPA		FT-Industrial		Total	
	Customers	Volumes	Customers	Volumes	Customers	Volumes	Customers	Volumes	Customers	Volumes
2001	20	1,503,971	13	163,120	8	187,384	36	1,083,027	77	2,937,502
2000	20	2,556,018	13	146,637	6	127,504	31	921,962	70	3,752,121
1999	19	2,965,769	13	139,349	6	90,694	29	715,985	67	3,911,797

all volumes MCF

(2) Agency Programs

The Company formerly provided an agency service to provide temporary assistance to any transportation-service customer who had lost its supplier. The agency service was provided as part of the Company's Interruptible Transportation Service, for a fee of 5 cents per Mcf. Revenues from the fee were credited to the Company's GCA (gas-cost) account.

The Company's newly revised services do not provide explicitly for an agency service. In general, transportation-service customers must join a pool, and pool operators must pass the Company's evaluation. Pool operators also enter into agreements with the Company committing them to fulfill their obligations, as discussed above. Thus, the Company may have decided that the agency service was no longer required.

Under the new Full Requirements Aggregation Service, available to suppliers (pool operators) delivering gas on a firm basis to the Company's city gates, the Company undertakes to supply gas temporarily to pool members in the event that the supplier fails to deliver. The supplier would have been approved by the Company, and the Company would have a satisfactory financial guarantee of performance of the supplier's obligations in order for the supplier to be participating in the program. In the circumstances of failure to deliver, the Company would attempt to supply the pool members, and would bill the supplier for whatever costs that the Company incurred in making the supply available to the supplier's customers. The Company could invoke whatever form of guarantee had been provided in order to be sure that the Company was paid for the supply that it provided.

For the Company's revised Interruptible Transportation Service, customers will have become a member of a pool, but the pool operator may not have been evaluated to the same degree as for firm service. As noted in the previous section, ITS customers who are "human needs and public welfare" customers must purchase a stand-by service or have alternate-fuel capability.

(3) Bypass Issues

Concern over possible bypasses was at the heart of the Company's interest in acquiring an interest in Columbia Transmission's pipeline facilities that subsequently became KO Transmission Corporation. Those facilities extended to the edge of the high-capacity pipeline that surrounds the downtown areas on either side of the Ohio River. The Company felt that, if it had an ownership interest in those facilities, then its large-volume customers could not connect directly to them without the Company's permission.

The Company and CG&E continue to have a significant bypass threat in the parts of their service territory that are near interstate pipelines. The Company (and CG&E) deals with that threat with well-designed gas transportation programs, and with special contracts at discounted rates as necessary. ULH&P has one such special contract.

(4) "Prodigal Son" Customers

The Company's newly revised transportation services have an initial contract period of one year, continuing month-to-month thereafter until cancelled on 30 days' notice. A customer cannot switch back to sales service during the effectiveness of its contract for transportation service. The tariff for firm transportation service (Rate FT-L) provides explicitly that, if a customer elects to return to sales service, the customer may have to bear all incremental costs incurred by the Company to provide the additional supply, including gas-supply costs and upstream transportation and storage costs, at the Company's discretion.

c. Conclusions

(1) ULH&P's gas transportation is efficient and effective.

The Company has just completed an updating of its transportation-service program, in the course of which it has given suppliers to the program considerably more flexibility. In addition, the Company has effectively improved its control of the program. Transitioning from customer-by-customer balancing to pool-by-pool balancing should make the program easier to administer, but also able to be controlled more tightly. Tighter control should allow further reduction of the capacity resources necessary to maintain service to all of the Company's customers, and thus reduce costs.

(2) CG&E/ULH&P has adequately managed a considerable bypass threat thus far.

Bypass is probably more of a threat on the Ohio side of the service territory, but is still a concern for ULH&P. The Companies' customer list, involving a number of large, well-financed and sophisticated firms and institutions, requires considerable care and sophistication from the Companies in order to keep them as customers. The fact that the Companies have not lost any customers to bypass is testimony to their effectiveness in maintaining those relationships.

(3) ULH&P's transportation program protects the interests of system-supply customers.

Transportation-service customers must provide their own pipeline capacity (and storage if they require it). No capacity assets are reserved by the Company to backstop their suppliers' performance. Customers who return to system supply are served on a best-efforts basis, or are required to pay for any additional capacity resources required to provide service to them.

System-supply customers have the highest priority for all receipt points. Transportation-service customers are individually metered, and are assessed a proportionate share of LAUF volumes.

System-supply customers are well served by all of these features.

d. Recommendations

None

5. Gas Balancing

a. Scope

This chapter addresses ULH&P's strategies and practices aimed at achieving a balance between the amounts of gas that come into its system with the amounts that it delivers to its customers. Aspects of those strategies and practices include the following:

- Metering and Testing
- Balancing Strategies and Practice
- Assignment of Capacity to Third Parties.

b. Background

(1) Metering and Testing

The total deliveries of gas into ULH&P's system are measured at gate stations. The CG&E/ULH&P distribution system is integrated, but there are measurement points where gas flows from one company to the other, such as where gas moves across the Kentucky-Ohio border. Thus, the total amount of gas delivered through the gate stations that serve ULH&P, less ULH&P's deliveries to CG&E, equals the total amount of gas delivered into the ULH&P system.

ULH&P's transportation customers are all metered continuously. City-gate deliveries for each customer are obtained from its pipeline nominations, so deliveries for each one's account can be matched to usage every day. Any imbalance is tracked day to day and settled monthly, or carried forward if the customer's pool operator so elects.

Company-use gas is also metered. Thus, the total amount into ULH&P's system, minus transportation-customer usage, minus company-use gas, is counted as system supply. Usage by system-supply customers is measured monthly, and at different times during the month because of cycle billing, so balancing between nominations and usage must be tracked over a longer period. In fact, balancing is tracked on an annual basis by comparing rolling 12-month deliveries into the system with rolling 12-month totals of deliveries out of the system. Daily and monthly imbalances for system supply are handled through operational balancing agreements (OBAs) with the pipelines.

A rolling 12-month total ending in June is used for assessment of the Company's system-wide lost-and-unaccounted-for volume (LAUF). The June percentage is used to determine retainage for transportation-service customers, but it is also watched for evidence of possible metering errors and system leakage.

The LAUF percentages, determined in June and excluding X5, for the last five years are as follows:

Year	LAUF percentage
1997	2.64
1998	2.12
1999	3.36
2000	3.26
2001	4.19

The upward trend in the percentages has been a source of concern. Early this year, the Company convened a Measurement Committee, to discuss the LAUF data and possible causes.

The Measurement Committee is composed of representatives from Gas Control, Meter Operations, Gas Engineering and Technical Services. Other members of Gas Operations may also attend committee meetings. The Committee meets about monthly to discuss possible sources of the problem, and results of solutions tried since the last meeting.

Thus far, the Committee has identified one significant measurement problem at the California Gate Station, where KO Transmission delivers to CG&E. That problem was corrected, and the search for other problems continues. The Committee Chairman reports no difficulty to date in obtaining member participation, and resources necessary to correct identified problems.

ULH&P is also concerned that leakage from the older parts of its distribution system are part of the problem. Earlier this year, the Commission approved a special rate mechanism to recover the costs of a 10-year plan to replace all cast-iron and bare-steel gas mains in ULH&P's system.

Regarding the Company's meter maintenance and testing programs, the Company provided the following report:

> "Meters are removed or field-tested on a periodic basis as outlined and required by KYPSC regulations. Meters that are removed from service are returned to the Cinergy Meter Shop where they are tested and then repaired or retired from service. The Cinergy Meter Shop has been certified by the Public Service Commission Meter Standards Laboratory. All personnel involved in meter maintenance and testing are Cinergy employees."

(2) Balancing Strategies and Practice

The Company's balancing strategy is implicit in its approach to metering, discussed above. Transportation-service customers are metered continuously, and their supplies are compared with their usage daily. The supplies and usage of all members of a pool are tracked together, and any pool imbalance at the end of a month that is outside of the tolerance elected by the pool operator is "cashed out"; *i.e.*, bought from or sold to the pool operator at an indexed price that is specified in the Company's balancing-service rate, Rate IMBS.

The Company's customer-by-customer metering data is available to the customer and its pool operator on the Company's electronic bulletin board. The pool operator is responsible for adjusting the amount of supply to each pool as necessary to balance members' usage. In the event that the Company issues an operational flow order (OFO), then daily balancing resumes. Penalties for non-compliance with an OFO are specified in the Company's tariff.

OFOs are issued on an ongoing basis for pool operators who do not provide supplies in quantities that reasonably match their daily loads. As noted in Chapter 4, Gas Transportation, pool operators are evaluated by the Company for financial soundness and operating integrity before they are allowed to serve customers on the Company's system.

As also noted above, the Company's system supply is balanced on a longer cycle. Every month, inputs into ULH&P's system are calculated from meter readings at pipeline gate stations, adjusted for deliveries to CG&E. Deliveries to transportation-service customers are adjusted for authorized imbalances, and then subtracted from net inputs into ULH&P's system. Company-use gas is likewise subtracted from supplies to the system. The difference is then compared to the total of the metered consumption of system-supply customers.

The monthly data is affected by cycle billing, and by unbilled volumes; *i.e.*, gas consumed within a month after a customer's meter has been read. When the monthly data is summed over a year, however, those effects "wash out".

The rolling 12-month data indicates how closely inputs into the system, adjusted for deliveries to CG&E, deliveries to transportation customers and Company-use gas, match the total of meter readings, *i.e.*, how closely the system is to balance. The rolling 12-month data ending in the summer months is the point when the numbers are the closest, as the effects of cycle billing and unbilled volumes are smallest in the summer. The June number is used for LAUF assessment and retainage.

The Company does not offer small-volume transportation service in Kentucky, so the special balancing provisions normally required for that service are unnecessary.

(3) Assignment of Capacity to Third Parties

As previously noted, the Company does not offer a small-volume transportation service in Kentucky, and requires that all transportation customers provide their own pipeline capacity, as well as their own storage capacity if they feel it is necessary. Accordingly, the only circumstance in which the Company assigns its capacity to third parties is in capacity-release transactions. Those transactions are conducted through the electronic bulletin board of the pipeline whose capacity is being released, and are done so pursuant to the procedures established and administered by the respective pipelines.

c. Conclusions

(1) ULH&P's gas measurement strategies are effective.

The CG&E Companies' integrated distribution system requires that balancing be tracked on an aggregated basis, as opposed to gate-station-by-gate-station. Balancing for the three affiliates – CG&E, ULH&P and Lawrenceburg Gas – is tracked separately, however, and the Companies maintain measurement facilities for deliveries by one company to another. Established procedures allow LAUF volumes to be computed and monitored for each company separately.

(2) The Company's new (interruptible) balancing service facilitates marketer use of ULH&P's system to serve transportation customers.

With its recent revisions to its gas transportation services, the Company has introduced several new services designed to facilitate marketer use of the Company's system, including not only the Interruptible Monthly Balancing Service, but also the aggregation services, Rates AS and FRAS, and the trading service, Rate GTS. Implementation of these services has required relatively little infrastructure investment that had not already been made. The Company already had an electronic bulletin board for tracking shipper movements on its system, for example. Rather, the new services involve using existing capabilities in new ways.

These changes also impact the Company's ability to control system operations more tightly. Weather in the Greater Cincinnati area is notoriously variable, so it is common for usage to be different from nominations, for space-heating requirements, at least. Allowing these short-term imbalances to be evaluated over groups of customers, rather than individually, should allow tighter control of each group. Tighter control means that less resources are required to serve the load, which lowers costs.

(3) LAUF is increasing, but it appears that proper attention is being given to this situation. *(Recommendation #1)*

The Company has responded appropriately to the observed increase in LAUF volumes. The Measurement Committee seems to have representation from all affected areas, and appears to be functioning smoothly. The reported prioritization for its efforts, involving financial impact and rapid results, seems sound.

d. Recommendations

(1) ULH&P should provide a summary report to the Commission regarding its activities associated with managing its LAUF. (*Conclusion #3*)

ULH&P's formation of the Measurement Committee is the appropriate step to have taken in order to investigate the LAUF situation. Liberty expects that this Committee will perform as intended and that explanations for the LAUF trends will be available to ULH&P management for appropriate action. As meaningful steps are taken to resolve whatever problems might be found in the LAUF situation, ULH&P should provide summary reports to the Commission indicating the nature of any problems found and the action ULH&P intends to take to correct such problems. These reports should indicate how any LAUF problems found might have impacted customers in the past, and how resolution of these problems will impact customers in the future.

6. Response to Regulatory Change

a. Scope

This chapter addresses ULH&P's responses to the changes in the business environment that have been caused by changes in regulation of the gas industry since the late 1980s. Aspects of those responses include the following:

- Changes in Objectives for Supply
- Changes in Supply Activities
- Capacity Cost Reduction.

b. Background

(1) Changes in Objectives for Supply

For many LDCs, taking over the supply function from the pipelines occurred in two stages. The first stage was substituting spot-market gas for pipeline supply once implementation of the FERC's Order 436 provided access to pipeline transportation capacity. The second stage involved taking over operation of assigned pipeline and storage capacity after Order 636 implementation. CG&E's and ULH&P's actions in the circumstances of those changes have involved pursuit of another objective. This was a specific program for obtaining direct physical access to the upstream pipelines that Columbia Transmission had used in its provision of full-requirements service to CG&E and its subsidiaries, including ULH&P.

CG&E's and ULH&P's current management indicates that the initial motivation for that objective may well have been self-defense. Since the pipelines had struggled in the early- and mid-1980s to deal with gas supplies for which they had contracted but could not take, LDCs like CG&E/ULH&P were concerned that the pipelines, and/or their own large-volume industrial customers, would decide to deal with each other directly, thereby bypassing the LDC. Should this occur, it would thereby eliminate the LDC's opportunity to derive some revenue from providing service to those customers. In the case of Columbia's service to CG&E and ULH&P, that concern was especially acute with respect to supplies from the south. Columbia Transmission's facilities in that direction extended to the edge of the Companies' central service area, putting the pipeline uncomfortably close to major industrial loads. The Companies' particular objective in these circumstances became acquiring an ownership interest in those facilities, in order that their customers could not tie into those facilities without their knowledge and permission.

The Companies' objective was pursued over a number of years, in a variety of forums. The Companies obtained an initial ownership interest in these facilities through a settlement of a Columbia Transmission rate case, and a number of related matters, that began in 1986. The bankruptcy of Columbia's parent, filed in July 1991, interrupted the Companies' progress, but the transaction was ultimately completed in 1994. Additional interests in these pipeline facilities were acquired in 1998 as part of another rate-case settlement.

As the business environment in the natural gas industry has evolved, the Companies' strategy for use of the facilities discussed above has taken on a proactive character, rather than a strictly reactive one. The pipeline facilities in which the Companies have an ownership interest extend to their interconnection with Columbia Gulf Transmission, Columbia's upstream affiliate. This enables the Companies to access that upstream capacity directly. Moreover, in 1996, the acquired interest in these facilities, placed in an affiliated company, KO (for Kentucky-Ohio) Transmission Company, was tied into the Tennessee Gas Pipeline system, providing further diversification for the Companies' supply.

In much the same manner, working through many of the same venues, the Companies have obtained access to nearby pipeline systems that had previously served Columbia. In ULH&P's case, even before Order 636 implementation, the Company already had a supply relationship with Texas Gas Transmission and Tennessee Gas Pipeline, and a storage service on ANR Pipeline.

(2) Changes in Supply Activities

Having attained sourcing flexibility through access to most of the pipelines that serve the region, the Companies have now turned to the objective of reducing costs to their system-supply customers. As reported in Chapter 1, Gas Supply Planning, the Companies do an exemplary job of forecasting their customers' requirements. To reduce costs, the Companies are trimming their capacity portfolios to match those requirements as their capacity contracts expire. The changes in ULH&P's capacity portfolio, to date and looking forward, were discussed in Chapter 3 of this report, Gas Supply Management.

ULH&P also reports experimentation with gas-supply contracting, in an effort to reduce costs further. The Company reports "… no economical or operational reason to enter into gas supply contracts for more than one year in length with suppliers." Thus, in recent years, the Company has managed its gas-sales customers' heating season needs with five-month firm supplier contracts, storage withdrawals, and spot-market purchases. The Company's philosophy is to procure firm gas supply during the period November through March in order to insure firm deliveries during peak periods to ULH&P's non-curtailable customers. During April through October, ULH&P procures spot-market gas on a monthly and daily basis, as required for system supply and to fill storage.

In an effort to reduce gas price volatility, the Company has purchased a portion of its supply at fixed prices linked to futures prices on the New York Mercantile Exchange (NYMEX). As also noted in Chapter 3, the Company continuously monitors prices as part of its formal hedging plan, and has bought quantities forward when the price seems reasonable on the basis of its analysis of historic prices and expectations of future gas prices.

Finally, the Company and its parent, CG&E, have contracted with an asset manager. As noted in Chapter 3, Gas Supply Management, the Company did not initiate this activity; rather, it was contacted by a prospective asset manager with a proposal. After conducting a comprehensive competition, an asset manager was selected for an initial 23-month period running from December 1, 2001 through the month of October 2003.

As part of this relationship, the Company operates very nearly as it would if it were conducting its own gas-supply operations, as it still must conduct annual competitions for winter-period gas supplies, and an annual competition for a peaking service. Moreover, the Company develops a "virtual" gas dispatch on a daily and monthly basis. This virtual dispatch is the basis on which the Company pays the asset manager for the gas that the Company receives.

As reported in Chapter 2, Organization, Staffing and Controls, Liberty is comfortable that the level of current staffing is adequate for these activities.

(3) Capacity Cost Reductions

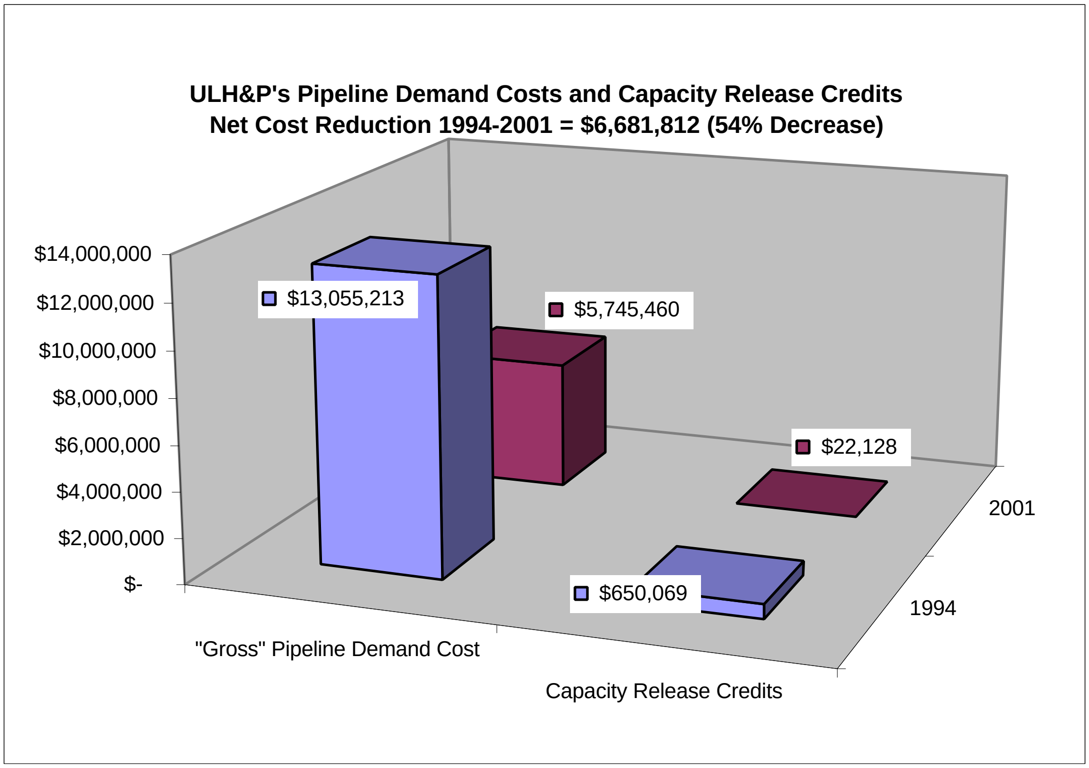
The Company's approach to reducing capacity costs has focused on eliminating unnecessary capacity costs. The Company's activities in pursuit of this objective have had two aspects. First, the Company has sharpened its estimates of what those requirements are. Liberty reported in Chapter 1 on the sophistication of its forecasting techniques. In Chapters 4 and 5, Liberty also reported on how a corollary benefit of the Company's changes to its gas transportation programs has been to reduce overall capacity requirements by requiring third-party suppliers to balance their customers' supplies with their usage more closely. These changes reduce the need for the Company to carry any extra capacity in order to ensure its ability to provide contracted levels of service.

The other aspect of the Company's activities in this area has been to relinquish pipeline and storage capacity as its contracts expire. In Chapter 3, Liberty reported on how the Company's capacity portfolio had been reduced to date, and on its continuing efforts in this regard.

The Company has also engaged in secondary-market activities – off-system sales and capacity releases – to reduce capacity costs. The Company has found, however, that the value of the capacity in secondary markets is so low that, coupled with the Company's ability to reduce its pipeline capacity, it cannot justify the effort involved in maintaining an active program. The Company will respond to an expressed interest in an off-system sale, and it posts any unused capacity on the respective pipelines' electronic bulletin boards, but the Company does not actively pursue these activities.

Figure 6.1, below, supports the Company's approach. In 1994, with an active secondary-market program, the Company was only recovering about five percent of its capacity costs through capacity releases. By focusing on trimming its portfolio, however, the Company has been able to reduce capacity costs by 54 percent since that time.

Figure 6.1



Note: Includes Pipeline "Transition Costs"

The Company's approach and results have been the same for parent CG&E. The same individuals engage in secondary-market activities for both companies, and the Companies' objective is to balance off-system sales and capacity releases between the two companies, depending on each one's available capacity. Table 6.1, below, reports the results for the two companies since 1998.

Table 6.1

Summary of CG&E and ULH&P Pipeline Capacity Release Credits and Off System Sales

		CG&E	ULH&P
Year 1998	Capacity Release	$ 1,528,578.12	$ 186,620.28
	Off System Sales	$ 199,683.28	$ 33,348.00
		$ 1,728,261.40	$ 219,968.28
Year 1999	Capacity Release	$ 437,241.86	$ 214,067.19
	Off System Sales	$ 510.23	$ -
		$ 437,752.09	$ 214,067.19
Year 2000	Capacity Release	$ 911,713.76	$ 119,297.12
	Off System Sales	$ 32,879.45	$ 5,504.00
		$ 944,593.21	$ 124,801.12
Year 2001	Capacity Release	$ 181,159.95	$ 22,128.01
	Off System Sales	$ -	$ -
		$ 181,159.95	$ 22,128.01

c. Conclusions

(1) CG&E/ULH&P's responses to changes in its business have worked out well for its customers.

As the gas industry has changed, the Companies have adopted a number of insightful strategies that have worked out well for their customers. Among those are the following:

- The Companies' early participation in pipeline special marketing programs, and their early provision of gas transportation service for large-volume customers, maintained those customers' usage of natural gas, rather than an alternate fuel, and has prevented bypass of their system.
- The KO Transmission system, developed initially as a defensive measure against pipeline encroachment on the Companies' markets, has become an effective tool for diversifying the Companies' sources of supply.
- The supply-source diversification that the Companies have obtained through their pursuit of direct connections to upstream pipelines has allowed the Companies to be aggressive in reducing un-needed pipeline capacity.

- The Companies' diverse access to sources of supply, and the interconnected nature of their distribution systems, have made them a desirable client for asset managers. The asset-management activity generates revenues that offset gas-supply costs.

(2) The Companys' mix of experienced staff people, with leadership from a different segment of the gas industry, has benefited their customers.

CG&E/ULH&P's Vice President of Gas Operations has a professional background in the pipeline segment of the natural gas industry, prior to joining the Companies. This background provides the Companies with insights into industry operations that are not usually found at an LDC. The understanding and fresh perspective provided by his different background has resulted in a willingness to try new things in gas-supply strategy, and generated an active interest in possibilities for new markets. In addition, the significant level of experience of CG&E/ULH&P's rank-and-file staff people provides important stability and continuity.

(3) ULH&P's customers realize significant benefit from the Company's association with CG&E.

CG&E's larger size brings the benefits of purchasing power and bargaining leverage to ULH&P's gas-supply strategy and operations. Moreover, the caliber of ULH&P's management team is higher than could be expected for a company of ULH&P's size operating on a stand-alone basis.

d. Recommendations

None

7. Affiliate Relations

a. Scope

This chapter of Liberty's report addresses the affiliate relations aspects of the Union Light, Heat, and Power Company (*ULH&P*) gas procurement practices:

- Structure of Affiliated Companies.
    - Placement and Structure of the Gas Procurement Function within the Affiliated Companies.
- Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.
    - Non-Gas Transactions with Affiliated Companies.
- Accounting and Reporting Issues for Affiliate Transactions
    - Cost Allocation Manual (CAM)
    - Allocation of Employee Time and Overheads
    - Other Accounting Issues
- Affiliate Transactions Relative to KRS 278
- Other Issues of Note

b. Background

(1) Structure of Affiliated Companies and Placement of Gas Procurement Function

ULH&P, a Kentucky corporation, is a wholly-owned subsidiary of Cincinnati Gas & Electric Company (CG&E), an Ohio Corporation. The parent company of CG&E is Cinergy Corp., a Delaware corporation and a registered holding company under the Public Utility Holding Company Act of 1935, which is also the parent of Cinergy Services, Inc., a Delaware corporation that provides a variety of administrative, management and support services to Cinergy's utility and non-utility subsidiaries. Other CG&E subsidiaries include Lawrenceburg Gas Company and KO Transmission Company. PSI Energy, Inc., a regulated utility in Indiana, and numerous non-regulated subsidiaries also exist.

ULH&P manages its operation through Cinergy's Regulated Businesses Business Unit and has only limited transactions with non-regulated affiliate companies, pursuant to its SEC-approved service agreements. In essence, all of its business is managed through the Regulated Business Unit. The Gas Resources Department (*Gas Resources*), reporting to the Vice-President of Gas Operations, is part of Cinergy Services, Inc., managed under Regulated Businesses.

(2) Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

Gas Resources provides procurement for ULH&P, CG&E and Lawrenceburg Gas Co. Each individual LDC holds its own gas commodity, transportation and storage contracts, and Mirant America's Energy Marketing, LP provides portfolio (asset) management services, paying

ULH&P a monthly fee in exchange for access to the gas assets. In the past, Gas Resources procured commodity supply from Cinergy Marketing and Trading, LP (CMT) (previously Producers Energy Marketing, LLC, also known as ProEnergy), but that contract expired March, 2000. ULH&P, through Gas Resources, has done very little or no business with the affiliate since that time. The Energy Merchant Business Unit received the RFP sent out to establish the asset management contract, but was not the winning bidder.

ULH&P and CG&E have executed two (2) Service Agreements providing for the transport of natural gas between the two companies at FERC tariff rates.

ULH&P transports gas over the KO Transmission Co. pipeline, an interstate pipeline subsidiary of CG&E, under FERC tariff rates. The pipeline has no employees, and all expenses are allocated from the affiliated companies.

Gas Resources does not provide gas commodity for electric generation, and offers no services to the electric sides of the utilities.

(2a) Non-Gas Transactions with Affiliated Companies.

ULH&P has service agreements, approved by the Securities and Exchange Commission (SEC), with Cinergy Services and with the non-utility affiliated companies which detail how costs for administrative and other services between the affiliates are to be allocated and charged. Note discussion in (3a) below.

(3) Accounting and Reporting Issues for Affiliate Transactions

(3a) Cost Allocation Manual (KRS 278.2205)

ULH&P states it is not required to file a cost allocation manual (CAM) with the Commission because its revenue from non-regulated activities does not exceed the required threshold. Nevertheless, ULH&P has used the comprehensive CAM prepared by CG&E in its rate case filings, and uses the processes and procedures set forth in this manual for its own cost allocation procedures.

ULH&P also has two (2) Agreements which detail how costs and charges are to be made between itself and affiliated companies. Each of these Agreements has been approved by the SEC.

The Utility Service Agreement dated March 2, 1994 between the Cinergy utilities (including ULH&P) and Cinergy Services, Inc. provides a Description of Services and Determination of Charges for Services, detailing how costs are allocated from Cinergy Services, Inc. Section IV of Appendix A to the Agreement defines a number of ratios to be applied to any costs or expenses which can not be directly attributed to a specific affiliate. These ratios appear to be a concerted effort to allocate costs in the most appropriate manner to each of the utility companies.

Section V then describes each function provided by Cinergy Services, and details the method of allocating costs, including the application of the appropriate ratio. This Agreement could serve as the foundation for a ULH&P CAM.

The Services Agreement dated May 14, 1999 between ULH&P and the multiple non-utility Cinergy companies outlines procedures for requesting, providing and charging for services between those entities. This Agreement also addresses Customer Information Disclosure issues in Section 5.11, prohibiting the release of ULH&P customer information to a Non-utility Company without the customer's written consent, except in limited circumstances (provision of or assistance with utility services, such as billing).

(3b) Allocation of Employee Time and Overheads

Employees do not keep timesheets; all costs are allocated based upon the methods outlined in the Agreements. The allocation method is embedded in the accounting system; employees can override the allocations if necessary, but this is not often done. The allocation ratios from the Utility Services Agreement are to be determined annually or at such time as required due to a significant change.

(3c) Other Accounting Issues

Invoices from affiliated companies to Gas Resources are handled differently from non-affiliate invoices. The Manager of Gas Resources approves all third-party invoices after they have been coded for entry into the accounting system. Invoice verification procedures provide adequate assurance of proper invoicing. The Purchase Gas Administrator verifies the invoice volumes and dollar amounts against general gas flow volumes and tariff sheets. Occasionally, meter volumes are used as a check, but in general, the gas flow volumes (shipped, scheduled, delivered compared to daily operations and storage volumes) are adequate. Work codes are assigned to the invoices, which provide accounts payable data entry with the necessary information to book the expense. Third-party invoices are sent to accounts payable for settlement with a cash instrument, usually wire transfer. Affiliate invoices, such as KO Transmission Co., go directly to the Manager of Accounting for journal entries and intercompany settlement.

There are no written procedures detailing the differences in the handling of affiliate and non-affiliate invoices. As the primary control in the system, if an affiliate invoice were to be sent to accounts payable (rather than elsewhere for journal entry), no vendor would be set up in the system and questions would be raised.

Because of the asset management agreement with Mirant, there are limited numbers of invoices coming into the Gas Resources Department. If there were any dealings with affiliates, they would not be noted as such because Mirant invoices for all gas supply.

Affiliated transactions for gas purchases are placed in a subsidiary account for intercompany purchases. The Chart of Accounts also shows some revenue and expense subaccounts for intercompany and associated company transactions.

(4) Affiliate Transactions Relative to KRS 278

Transactions between ULH&P and its affiliates that are charged at tariff rates appear to meet the definition of arm's length in KRS 278.010.

ULH&P states it is not required to provide a Cost Allocation Manual. The use of a shared services organization, however, and therefore the allocation of those shared costs among regulated and unregulated affiliates, means that the KPSC needs to understand how that process is accomplished. ULH&P files annual reports to the Commission, as required by the Commission's order in Case No. 94-104 and as required by 807 KAR 5:080, which substantially fulfill the information requirements of a CAM.

c. Conclusions

(1) ULH&P procures gas through a shared service, in-house procurement model that presents no affiliate relations issues. The day-to-day responsibility of gas deliveries to the city gate falls under an asset management contract.

The Gas Resources Department of Cinergy Services, Inc. provides gas procurement for ULH&P, CG&E and Lawrenceburg Gas. This shared service model allows for less duplication of employees and overheads than having each company provide the same function. At the same time, commodity and transportation contracts are held in each utility's name, eliminating cost and revenue (capacity release, etc.) allocation issues that could complicate ratemaking procedures. A gas purchase contract with an affiliated gas marketing organization expired more than two (2) years ago and presents no affiliate issues.

(2) ULH&P moves gas to affiliates and through affiliate pipelines at tariff rates, which meets the requirements of arm's-length transactions under KRS 278.

Movement of gas through an affiliated interstate pipeline is at filed FERC tariff rates, and existing service agreements moving gas between ULH&P and CG&E mandate FERC rates, as well. Affiliate transactions at published tariff rates, the same rates available to all potential customers, removes issues of cross-subsidization of costs.

(3) ULH&P states that it is not required to produce a Cost Allocation Manual (CAM), despite extensive allocations of costs between and among affiliates. An annual report to the Commission provides much the same information as would be included in a CAM.

One benefit of a Cost Allocation Manual is to allow the Commission to study how costs are allocated not only among regulated and non-regulated activities within a utility, but also between and among affiliated entities and the utility itself. The allocation of costs from shared service organizations deserves thoughtful consideration on the part of the utility holding company, as each ratemaking body works to ensure that its customers pay the full costs of their service, without bearing costs that do not belong to those customers.

The Annual Report to the Commission from ULH&P evidences the effort made to reasonably and fairly allocate shared service costs among Cinergy's affiliated utilities.

(4) There are no written procedures detailing how affiliate and non-affiliate invoices are handled. Invoices from affiliate companies to Gas Resources are handled differently than those from non-affiliated companies. *(Recommendation #1)*

Written procedures help define job responsibilities and highlight details in handling activities when significantly different courses of action are prescribed. Further, as staffing levels tighten, the risk increases for a knowledge base to be lost (due to retirement or an employee quitting) or unavailable (due to illness or vacation, for example).

After being checked for accuracy, non-affiliate invoices go to the Manager of Gas Resources for eventual forwarding to accounts payable, while affiliate invoices are sent directly to accounting for journal entry and intercompany settlement. The responsible employee had learned this distinction over time, without knowing why the invoices were handled differently or to which suppliers of goods and/or services each procedure might apply. While, in general, Gas Resources has done a good job in detailing policies and procedures (see Chapter 2), the department should remedy this lack of written procedures in how affiliate and non-affiliate invoices are handled.

(5) Allocation of employee time and overheads is embedded in the accounting system, incorporating the methodology of the Service Agreements. Employees do not keep timesheets, and the opportunity for exception time reporting is rarely used. Employees may not be aware of exactly how their costs are allocated to affiliates, and therefore are not always able to identify whether an activity warrants exception reporting. *(Recommendation #2)*

Particularly in a shared services environment, employee understanding of both 1) the reasons behind the need for fair and accurate allocation of shared costs and 2) the process of that allocation becomes very important. In response to the Commission's Order in Case No. 2001-092, ULH&P determined that employee training would be helpful in raising awareness of, and attention to, the issues around such cost allocation. In a letter dated April 30, 2002, the company provided to the Commission an outlined training plan for employees, which the company hopes to begin in July of this year and complete by year-end. Based upon the outline, the proposed training would appear to provide an adequate foundation for increasing employee involvement in the fair and accurate allocation of shared costs at Cinergy and ULH&P.

d. Recommendations

(1) Written procedures should be developed detailing the differences in how affiliate and non-affiliate invoices should be handled. *(Conclusion #4)*

Written procedures developed by Gas Resources should include several points. First, the procedures should detail the physical process of handling affiliate and non-affiliate invoices – how each is verified, whose approval is required and where each is to be forwarded. This level of detail would allow a new or temporary employee to carry out the function. Secondly, the procedure should list the affiliated companies most likely to submit invoices so the employee could evaluate how to appropriately handle an invoice from an unknown supplier. Finally, the reasoning behind the different handling should be summarized, to help new or cross-trained employees better understand the process.

(2) ULH&P should continue implementation of the Cost Allocation Training Program currently being developed in response to the Rate Case Order 2001-092. *(Conclusion #5)*

The Cost Allocation Training Program submitted to the Commission details the subject matter to be covered, targeted groups, the timing of the proposed training, the training agenda, and the instructors responsible for the training. Topics in the submitted training agenda include:

I. Background (PUHCA, FERC, Regulatory Agencies, and Cinergy corporate structure),
II. Service Company Training (Organization, Service Agreements, Pricing, Direct vs. Allocable Charges, Legal Entity Allocations (the embedded allocation methodology), Accounting Requirements and Regulatory Reporting),
III. Utility – Non-Utility Affiliate Transactions Training (Service Agreement, Regulatory Requirements, Appropriate Transactions, Pricing, Accounting Requirements, and Regulatory Reporting),
IV. Company and/or Gas and Electric Split Allocations Training (Appropriate Transactions, Accounting Requirements, and Annual Allocation Study), and
V. Compliance Monitoring (Responsibility of Employee, Role of Supervisor/Management, Role of Cost Accounting, and Internal Audit).

ULH&P has agreed to forward to the Commission a copy of the educational materials to be used for the training when those materials are developed.

III. Company-by-Company Reports

E. Western Kentucky Gas Company

1. Gas Supply Planning

a. Scope

This chapter of Liberty's report addresses the following aspects of the Western Kentucky Gas (*Western or WKG*) gas supply planning practices:

- Integration with Corporate Plans
- Load Forecasting/Risk Analysis
- Balancing Supply Options/Capacity Portfolio Analysis
- Supply Planning Flexibility
- Impact of New Markets
- Monitoring of Key Assumptions and Plan Implementation
- Peak Period Performance

b. Background

(1) Integration with Corporate Plans

Western, a division of Atmos Energy Corporation, is headquartered in Owensboro, Kentucky. Corporate planning as well as gas supply planning for Western is performed within Atmos, at its offices in Dallas, Texas. Atmos conducts its centralized gas control operations for all of its divisions at a facility in Franklin, TN.

Western has 180,000 customers, about 13% of Atmos' 1.4 million customers. The corporate structure within Atmos reflects a centralized approach to gas supply planning within the corporation. This translates to the use of common assumptions, common approaches and common priorities across the five business units of Atmos.

The Atmos Vice President has expressed his desire to unify and standardize procedures at the gas supply department by evaluating staffing requirements, and potentially hiring new personnel to augment current forecasting and planning efforts.

Western currently does not prepare a report comparing its forecasted gas supply plan to actual values, neither for pricing data nor for sendout plans. This is in part due to the static forecast generated for annual planning purposes, which does not consider weather scenarios against which actual sendout values can be compared.

(2) Load Forecasting/Risk Analysis

Load forecasting is a key component in evaluating all risks involved in gas supply planning. The key source of variation in gas sendout is weather, which is currently not a part of Western's annual gas supply plan. This omission has prevented the Company from properly assessing its capacity portfolio vis-à-vis its potential annual sendout. Woodward Marketing currently manages Western's gas supply portfolio under an agency agreement. During the course of this project, Western was in the process of issuing an RFP and evaluating bids for a new agency agreement to run for a four-year term until 2006.

The existence of the current agency agreement has provided Western with greater flexibility while taking away incentives to improve forecasting procedures. The lack of variability analysis in the demand forecast was also reflected in the request-for-proposals (RFP) for the new agency agreement. Atmos has acknowledged this deficiency, and will work to resolve this as a part of its desire to improve and standardize forecasting procedures for Atmos' business units including Western.

The selection of the gas supply outsourcing business model for Western has its benefits and risks. One of these risks, counter party risk, has been acknowledged but not made a formal part of the RFP process. Western has acknowledged the risk involved in heavy reliance on a sole supplier –currently its affiliate Woodward Marketing- for the bulk of its gas supply. Western does feel that the significant discount provided by the agency agreement compared to other alternatives is a significant benefit. While this is not a direct concern, some analysis regarding the tradeoff between increased cost vs. decreased reliance on a sole supplier should always be a part of the evaluation regarding any new agency agreement. For example, Western addressed credit worthiness of potential suppliers as part of its agency agreement evaluation process.

The additional capacity within Western's system allows for better risk management at the cost of reserving resources in excess of coldest weather conditions. However, the lack of a detailed forecast analysis has not enabled the identification of the amount of additional capacity on Western's system.

(3) Balancing Supply Options/Capacity Portfolio Analysis

Western's portfolio is currently based on a peak day sendout assumption of 65 HDD. Liberty's analysis of Western's gas supply portfolio indicates that the system is capable of handling an increase of 20% per month on an annual basis over the total energy sendout implied by 'Case' weather for Lexington and Louisville assumed for TXG and TNG, respectively.

This increase corresponds to assuming 75 HDD on a peak day. This figure is in line with extreme weather that has occurred in Western's service territory as indicated by Liberty's general analysis on forecasting. However, on an annual basis, the system has additional capacity to allow meeting 'Case' weather assuming the highest historical HDD for January and total annual HDD. This suggests that modifications to the portfolio can ensure a better fit between potential demand and the supply portfolio by acquiring or developing additional storage capacity and reducing firm pipeline capacity, for example.

Western's supply and pipeline capacity, by allowing for easy handling of increased demand and widely spread market areas, makes the task of determining how resources will meet forecasted load relatively easy. Western has acknowledged that Texas Gas, for example, allows shifting of usage between its zones, hence rendering moot the specific capacity allocations by meter as outlined in the contracts.

Western's potential need for more peak day capacity, for example on East Diamond Storage Field operated by Woodward Marketing needs to be evaluated further. This element has been included in the evaluation of the agency agreement RFP as a direct cost benefit in comparison with other bidders. Given this is the case, Western should evaluate obtaining additional capacity on the East Diamond Storage Field as contract retirements are expected throughout 2003-2005, and properly assess the amount of firm pipeline capacity that can be supplanted upon the generation of a comprehensive gas supply forecast including potential variation due to weather and other factors such as customer growth.

Western's peak-day estimate book contains weather sensitivity analysis for the four zones that are considered for planning purposes: Texas Gas Zones 2, 3 and 4 and Tennessee Gas Zone 2. Since this analysis is based on allocating firm capacity by zone, it does not account for savings that may be achieved for the total portfolio. Generating an annual demand forecast would enable matching resources on a load duration curve, and the assessment of the mix of firm capacity vs. storage capacity that would be optimal for the system.

(4) Supply Planning Flexibility

Western's reliance on an agency agreement for gas supply, while providing Western efficiency in planning, limits supply alternatives for the four-year term of the contract. This was true for the agreement that just expired, and is also expected to be the case for the new agreement under consideration.

Western's expected improvements to gas supply forecasting will allow better planning flexibility, since the weather scenarios considered in the peak-day estimate book augmented by weather scenarios considered for annual sendout will verify the adequacy of Western's gas supply portfolio and provide insight into expected modifications to contracts as they expire.

(5) Impact of New Markets

Western does not consider any specific impact of new markets; and does not anticipate any serious changes to its system.

(6) Monitoring of Key Assumptions and Plan Implementation

Due to Western's agency agreement, monitoring of key assumptions and plan implementation have not been a priority. Key assumptions are a part of all comprehensive forecasts, and should be indicated and periodically checked within an annual gas supply planning process. The allocation of firm capacity to requirements indicated for each of the four demand zones on Western's system has made plan implementation relatively simple at the cost of potential excess capacity which can be better identified and mitigated using an annual forecast in addition to a peak-day forecast.

The current PBR mechanism and agency agreement provide minimal incentive for Western to improve forecasting procedures and track plan implementation. The only incentive is a small one and that is to better forecast volumes in order to take advantage of more attractive base load price versus swing price.

(7) Peak Period Performance

Liberty's assessment of Western's gas supply portfolio, using customer and usage per customer data provided for the peak-day forecast, indicates that the system may benefit from supplanting firm pipeline capacity with storage capacity to ensure a better match between its gas supply portfolio and its load duration curve. As indicated earlier, annual forecasts considering various weather scenarios would enable the quantification of additional storage needed and the amount of firm capacity that can be retired.

One of the responses to Western's RFP for its agency agreement contains a bid from Woodward Marketing that is valued on the basis of 10KDth/day capacity offered <u>anytime on an annual basis</u> as a part of the proposal. Liberty believes this analysis should be extended to determine the proper amount of additional storage that would provide better peak period performance in the future while reducing costs to the consumer by supplanting firm capacity.

c. Conclusions

(1) Load forecasting should be a top priority for Atmos's Gas Supply Department. (*Recommendation #1*)

Western's load forecasting procedures do not include several elements that are outlined in the general analysis and guidelines on forecasting contained in Section I of this report. Most importantly, Western's gas supply plan does not include adequate weather sensitivity analysis similar to its peak day sendout requirements analysis. The same gas supply plan is replicated in its solicitation for asset management services. Interviews at the company indicate the intent to hire a forecasting specialist to unify forecasting practices across business units and to improve capabilities in this area.

(2) Insufficient attention to load forecasting has resulted in a capacity portfolio that may not be appropriate for Western's load. (*Recommendation #2*)

Western reports that its capacity portfolio is based on a peak day sendout assumption of 65 HDD. Liberty's ROGM analysis suggests that, with the base load and use factors supplied by Western, the Company's capacity portfolio could handle a peak day of 75 HDD. This number is not far off of the peak-day design criterion that we would recommend for the Lexington area (74 HDD), but it is a bit conservative for Louisville (72 HDD). Western reported that it uses Lexington for the service territory that it serves from the Tennessee Gas Pipeline system, and Louisville for the area that it serves in Texas Gas's Zone 4, which is Texas Gas's northernmost zone.

An important implication of Liberty's analysis is that Western appears to have excess capacity on other than peak days. Liberty estimates that Western's capacity portfolio could handle 20 percent more demand than that implied by our Test Case weather. Liberty's Test Case weather is a combination of 1) the maximum number of heating degree days (HDD) recorded for January, as reported by the National Climactic Data Center of the National Oceanic and Atmospheric Administration, for each of the weather observation stations reported by the Kentucky LDCs as used by them for load forecasting , plus 2) the total annual number of HDD that occurred in 1978 (which had the highest number of HDD in the last 54 years), distributed among the other 11 months in proportion to the average. For two of the six weather stations used by the companies, two standard deviations above the average had a higher number of HDD than our Test Case (set equal to 1978); for the other four, two standard deviations was lower. In no case was the difference more than 2.6 percent between our Test Case HDDs and two standard deviations above the average.

Thus, while Western might be pretty close on the peak day, Liberty's analysis suggests that it should supplant some of its FT capacity with either more storage or peaking capacity in order to bring its total capacity portfolio more in line with its load.

Liberty's analysis does not include contractual constraints, such as specific deliverability for each city-gate delivery point. Our sense is that LDCs are usually allowed to use capacity without adherence to limits on delivery to specific meters as long as the same total amount of gas is taken within a particular pipeline rate zone. Thus, contract meter-station constraints are not usually binding. Given the limitation of current forecasting data and the possibility of tightening of pipeline zonal delivery constraints, Western's supply portfolio is reasonable but indicates room for improvement to better match annual sendout generated from a forecast incorporating potential weather variation.

d. Recommendations

(1) Load forecasting, for Western Kentucky Gas, at least, needs increased emphasis within Atmos's Gas Supply Department. (*Conclusion #1*)

More detailed gas supply forecasting will benefit Western and its customers on two fronts: 1) It will enhance gas supply planning efforts, 2) it will enhance competitive bidding of Western's asset management RFP. The first priority for load forecasting improvements should be an analysis of annual weather scenarios and variation assumed by the company, and an augmented gas supply plan incorporating demand implied by these weather scenarios. The second priority would be a detailed analysis of number of customers and usage per customer and their potential variation, and weather sensitivity assumptions that may be added to commercial and industrial rate classes.

(2) The Company should identify any changes that may be needed in its capacity portfolio, and begin to negotiate for those changes as opportunities present themselves. (*Conclusion #2*)

Given a more detailed load forecast, Western can proceed to analyze changes that may need to be made in its capacity portfolio by identifying excess capacity vis-à-vis its projected demand. With this information, the Company can evaluate modifications to its portfolio given upcoming contract end dates.

Liberty's analysis using only peak-day forecast information indicates that Western may benefit from additional storage capacity that would replace firm capacity expirations in 2003-2005. Western should assess alternatives including additional capacity on East Diamond Storage offered as a part of Woodward's agency agreement proposal and the development of its own storage field to increase peak-day deliverability. Such analysis should include cost-benefit analysis comparing alternatives that would strike a balance between increased system reliability and ensuring the maximum possible cost savings for Western's customers.

2. Organization, Staffing and Controls

a. Scope

This chapter of Liberty's report addresses the aspects of Western Kentucky Gas Company (Western) management and operations that relate to its overall organization, staffing and controls:

- Organizational Structure.
- Staffing.
- Approval Authorities.
- Work Process Definition and Control.
- Documentation Requirements.
- Auditing.

b. Background

(1) Organizational Structure & Staffing

Natural gas supply planning, procurement and management for Western is handled by the Gas Supply Department (Department) of Atmos Energy Corporation. The Department is directed by the Vice President, Gas Supply, Atmos Energy Corporation, located in Dallas, Texas. Functionally, this Department has three sections – Gas Supply Planning, Nominations and Scheduling, and Gas Control. The planning function is located in Dallas, Texas, and the other two functions are located in Franklin, Tennessee. The planning section consists of a director and five analyst-type employees. The nominations and scheduling section consists of a director, manager and three technicians. The gas control section (which is a 7 days per week, 24 hours per day operation) consists of a director, manager, supervisor, and seven gas controllers. The three directors report to the Vice President, Gas Supply.

The Gas Supply Department procures and manages gas supplies for five separate business units or LDCs, one of which is Western. These five business units are Atmos Energy Louisiana, Energas Company, Greely Gas Company, United Cities Gas Company, and Western. These business units are not really separate legal entities, nor affiliates in any sense, but simply different divisions of the Atmos Energy Corporation, operating under names such as Western Kentucky Gas Company.

The Vice President, Gas Supply reports to the Senior Vice President, Utility Operations for Atmos, who in turn reports directly to the Chairman, President & Chief Executive Officer of Atmos.

Gas Supply Planning

The Gas Supply Planning section is responsible for the longer term supply planning (i.e., seasonal and annual) which includes forecasting the requirements and planning supply purchases and storage utilization to meet those requirements. This section prepares and submits Request for Proposals (RFP), evaluates proposals received and selects the supplier. Then Gas Supply Planning negotiates the general terms and conditions of the supply contracts and coordinates the contract preparation and finalization through Contract Administration. This section is also responsible for the verification and approval of all supplier and pipeline invoices. Additionally, it has responsibility for regulatory support to the Business Units in gas supply related matters, such as Gas Purchase Plans, data request responses, etc. Lastly, this section provides Rates Administration section of Accounting the estimated gas commodity costs for Gas Cost Adjustment filings.

This section is currently developing plans to add a sixth analyst position to be responsible for all of the peak day studies required for each of the 30 or more rate areas in which Atmos operates. Currently, peak day studies are handled on a case-by-case basis when they are required, as opposed to being planned and conducted on a consistent basis.

Nominations and Scheduling

The Nominations and Scheduling section is responsible for the daily management of supply agreements and the coordination with Gas Control in maintaining gas flows within daily contractual parameters. The responsibilities include the first-of-month nominating and confirmations with suppliers as directed by the supply plans provided by Gas Supply Planning. This section is also responsible for intra-month nomination increases or decreases and providing notification to supplier with appropriate contract identification and quantity to be reduced or increased. The nominations and scheduling section communicates with Gas Control daily to obtain system supply needs to stay within contractual and/or storage operating parameters. Additionally, this section is responsible for the overall end-user transportation program, which consists of scheduling, and/or confirmations of all quantities transported to end-users through the Company's systems. This includes the coordination of the transportation program with the marketers, the Accounting Department and Business Units by assisting with explanations and/or clarification of pipeline transportation procedures. Finally, this section is responsible for monitoring all pipeline Electronic Bulletin Board (EBB) for Operational Flow Orders, actual or allocated quantity information, scheduled nominated quantities, important pipeline information such as maintenance schedules, constrained areas, capacity postings (if needed), etc.

Gas Control

Gas Control operates 7 days per week, 24 hours per day. The gas control section is responsible for the daily operation of the Company's gas control function by monitoring, balancing, and control of gas supply deliveries across the systems to ensure that the systems are performing in a safe and reliable manner. Gas Control ensures contractual compliance with pipeline transportation and storage agreements and also provides storage management to ensure proper level of inventories is maintained in order to provide the expected deliverability when required. Additionally, Gas Control estimates throughput requirements for the near term (3-4 days out) and communicates these estimates to the Nominations and Scheduling section for daily supply scheduling.

Performance Measurement

At Atmos, there are three levels of performance incentive programs, or rewards for employees. All three programs are tied to Atmos earnings per share.

The first program is for executives, and includes a bonus program.

The second performance program is called the Management Incentive Program, or MIP, and is designed for high-level business unit officers, such as the Directors within the Gas Supply Department.

The third performance program is called the Variable Pay Plan, or VPP, and is for all other employees not covered by either of the above two plans. The VPP sets three levels of performance from minimum, which is 1% of salary as the reward, the target, which is 2%of salary as the reward, and the maximum, which is 3% of salary as the reward.

Employees in the Gas Supply Department are all evaluated annually, and are able to receive merit pay increases based on their own individual performance. Personnel evaluations are based on four categories that include job knowledge, accomplishments, decision-making, and planning. The Directors are able to give varying merit raises to their employees, as long as the total dollars allocated to them stay within specified budget limits.

Training

The Gas Supply Department is staffed with many senior and experienced individuals. In the group including the Vice President, the Directors and Managers, the least amount of experience in the gas business at Western or a predecessor company is 25 years. There are no formal training programs at Western, and a limited amount of cross-training does occur. However, on balance, the senior individuals feel that they are the knowledge links in the organization, and that information flows as necessary in the course of their normal activities. In addition, there are weekly staff meetings for exchange of current information and discussion of strategies for gas management. Typically, Department staff meetings are held on Monday, and are followed by Section staff meetings.

Job Descriptions

Job descriptions at Western are significantly out of date. Most job descriptions were last reviewed in 1998. Significant changes in the organization have taken place since then, and as a result, these job descriptions do not adequately describe current jobs. In some cases, the existing job descriptions are for positions that no longer exist.

(2) Approval Authorities

The Gas Supply Department engages in an annual planning process involving all of the essential areas of the Department and that results in the Strategic Plan for the Department. The document is called the "Goals and Objectives Book". It contains a vision and mission statement, and individual goals and objectives for each LDC that incorporate manpower resources and forecasts, and budgets. It contains specific objectives for each of the five Atmos LDCs. This book is first prepared at the "grass-roots" level in the Department, and then is sequentially approved by each layer of management in the Department.

When the Department is satisfied with this Book, it is taken to the Shared Services Board for approval. The Shared Services Board contains Presidents of all the five business units reporting to the Senior Vice President, Utility Operations, and all of the four vice presidents reporting to the CFO. The current chair of this Board is the President of Atmos Energy Louisiana. The chair position rotates every two years.

After approval by the Shared Services Board, the Book is taken to the Management Committee for approval and after approval here, it is sent to the Board of Directors for approval. At each step, the fundamentals of the book are presented in less detail, but Western feels that the review is quite detailed at the level of the Shared Services Board, such that senior management is involved, and knowledgeable with respect to the operations and plans of Western.

Once the book has received Board approval, each Director meets with his employees to review the goals and objectives for the year, and to discuss the challenges and plans for the year. Employees are not specifically evaluated on how they individually or as a group met the goals and objectives contained in this Book, however, employees are evaluated on how they perform their specific job duties as they relate to these goals and objectives.

There is no official approval matrix designating who in the Department has what responsibility, or who can approve various levels of procurement for gas supply. The Director of Gas Supply Planning feels that he has sufficient knowledge and experience to know who needs to approve what decisions. The Vice President of the Department makes most of the final decisions on gas supply, after review of the results of RFP analysis; higher levels of management approval are only required if the term of a contract is for greater than 5 years.

(3) Work Process Definition and Control

Formalized, written policies and procedures guiding the operations for Western are not adequate. There are no standardized procedures covering the fundamental steps of gas procurement and gas supply management, nor are there any procedures for dealing with any affiliate operations. The procedure for risk management is an abbreviated one-page statement of policy.

Some general text descriptions of Western gas procurement operations do exist, but they are not in the form of procedures, are dated 1995 and 1996, and so are quite out of date as well. These general discussion-type procedures lack necessary detail, and lack delineation of specific responsibilities by individual or function. Western is in the process of working to resolve this situation, but there is no specific timetable for completion of the project.

(4) Documentation Requirements

Documentation of gas procurement and supply management activities within the Gas Supply Department is satisfactory, and each employee has a copy of the Goals and Objectives Book. However, there are no formalized reports that flow out of the Gas Supply Department into higher levels of the Atmos organization. Western indicated that necessary information is transmitted to senior management every two weeks at meetings of the Management Committee. Further, since the plans, goals and objectives of the Gas Supply Department are prepared annually and approved by each level of upper management through the Goals and Objectives Book, Western feels that senior management is appropriately involved in approving the direction of the Department, and in monitoring this direction through the regular meetings of the Management Committee.

(5) Auditing

Ernst and Young (*EY*) conducts the internal audit of the Gas Supply Department, as opposed to there being internal audits conducted by an Atmos internal auditor. Liberty has reviewed the results of the last two EY audits, done in August of 2001, and in June 2000. All but two of the findings from the 2001 audit have been resolved. One outstanding audit item related to supplier lists and formal supplier qualifications. This is a difficult item for Atmos to resolve because of the lack of uniformity of SCADA information among the five Atmos LDCs. The Department does expect to have an interim resolution of this item in the near future, but was not sure when there would be final resolution of this item. The issue of resolving supplier verification on the Western system is much easier to handle because of the sophistication of Western's SCADA system. The Director of Gas Supply Planning is further augmenting capabilities in this area by specifying how potential gas supply bidders are qualified. Part of the qualification process will incorporate Dun & Bradstreet ratings, and interaction with the Atmos Treasury Department to include ratings of financial resources of potential gas suppliers.

The second open audit item related to verification of pipeline quantities. The Department expects to have resolved this item by the end of June 2002.

Senior management is well aware of the status of these outstanding audit items because EY sends a quarterly report to senior management on the status of all open internal audit items.

c. Conclusions

(1) Job descriptions for positions in the Gas Supply Department are out of date, and a number of them do not properly describe the current positions in the Department. (*Recommendation #1*)

Job descriptions in the Gas Supply Department are significantly out of date. Most job descriptions were last reviewed in 1998. Significant changes in the organization have taken place since then, and as a result, these job descriptions do not adequately describe current jobs. In some cases, the existing job descriptions are for positions that no longer exist.

(2) The Gas Supply Department does not have the necessary documented procedures that detail the various activities associated with procurement and management of natural gas supplies. (*Recommendation #2*)

Formalized, written policies and procedures guiding the operations of the Gas Supply Department are not adequate. There are no standardized procedures covering the fundamental steps of gas procurement and gas supply management, nor is their a formalized approval matrix designating who in the department has what responsibility. Some general text descriptions of gas procurement operations do exist, but they are not in the form of procedures, and they are dated 1995 and 1996. These general discussion-type procedures lack necessary detail, and lack delineation of specific responsibilities by individual or function.

In addition there are no procedures detailing the requirements for dealing with affiliate operations, or with other Atmos organizations conducting activities in unregulated areas in order to ensure that inappropriate cross-subsidization of activities does not occur.

Finally, the existing one-page guidelines relating to risk management are not extensive enough to provide the necessary definitions of risk activities, delineation of specific responsibilities, necessary management control functions, or overall levels of responsibility for decision-making.

(3) The Gas Supply Department does not have the necessary training program to address the training requirements related to addition of new employees, cross-training, or departure of employees having significant knowledge of Department operations. (*Recommendation #3*)

Because the Gas Supply Department is staffed with many senior personnel who have considerable knowledge and experience relevant to the operations of Western, the Department must take prompt steps to develop training programs that will enable training of new employees, cross-training of current employees, and provide for appropriate knowledge transfer when these employees of long tenure depart.

(4) The Goals and Objectives Book prepared annually by the Gas Supply Department is an important planning and management tool.

The "Goals and Objectives Book" is important as both a planning and management tool because it involves a broad spectrum of employees in its preparation and review, from the "grass-roots" level in the Department to the Board of Directors. While this document is not labeled as such, in reality it is the Strategic Plan for the Gas Supply Department. It contains appropriate vision and mission statements, and individual goals and objectives that incorporate manpower resources and forecasts, and budgets. It contains specific objectives for each of the five Atmos LDCs, and provides a means for the Department to measure its progress against planning objectives as the year progresses.

(5) The Gas Supply Department is able to accomplish a significant volume of natural gas planning, procurement and management activities with a relatively small staff because of the use of Agency Agreements (Asset Management Agreements).

Atmos is currently functioning under a business model for the Gas Supply Department that enables it to accomplish significant activity in the areas of natural gas planning, procurement and management. Central to this model is the use of Agency Agreements, or Asset Management Agrements, such as the one the Department has with Woodward for management of gas supply for Western. This is discussed in greater detail in Chapter 3, Gas Supply Management. As a result of the use of this business model, the Department is able to function effectively with a relatively small staff, considering the large quantities of natural gas involved for each of the five LDCs for which it is responsible.

(6) Internal audits of the Gas Supply Department conducted by Ernst and Young are effective.

Atmos has made arrangements with Ernst and Young (EY) to conduct internal audits of the Gas Supply Department, as opposed to there being internal audits conducted by an Atmos internal auditor. Liberty feels that this is an appropriate method of conducting internal audits for the Department. The issues identified in recent audits have been relevant to issues Liberty feels should be addressed in internal audits, the audit findings have received appropriate management attention, and audit recommendations are receiving appropriate follow-up.

d. Recommendations

(1) Revise and update job descriptions for the Gas Supply Department to appropriately reflect the current staffing of the Department, and the current responsibilities of this staff. (*Conclusion #1*)

The Gas Supply Department should begin a program to update all job descriptions. This program should ensure that all job descriptions are reviewed to determine that they accurately describe the current responsibilities and activities of the positions for which they were written, and that job descriptions for positions that no longer exist are removed from the files of active job descriptions.

(2) Develop formalized, written policies and procedures that will cover the planning, procurement and management of natural gas supplies for which the Gas Supply Department is responsible. (*Conclusion #2*)

The Gas Supply Department should begin a program to develop formalized, written procedures covering all aspects of gas supply planning, procurement and management activities. These procedures should provide sufficient detail of necessary actions and assignment of responsibility for these actions such that they can be used both for training of new employees, and cross-training of existing employees. A formal approval matrix is the best way to designate who in the department has what responsibility.

Procedures should be developed to cover affiliate relations activities, and the necessary controls with affiliated organizations and other Atmos entities dealing in activities in unregulated areas. Specific care must be taken to ensure that procedures deal with necessary controls in areas where cross-subsidization could occur.

Risk management procedures should be expanded to provide a more complete picture of the areas of risk to which the Gas Supply Department is exposed, assignment of specific responsibilities for activities in these areas and establishment of appropriate functions for management review and control of risk related activities.

The area of risk management is complex, and in many cases new to natural gas utility operations. Therefore, Section I.B of this report contains the outline of a typical Risk Management Policy.

(3) Develop a formal training program for the Department that will provide for training of new employees, cross-training of existing employees, and address the issue of losing significant Department knowledge base when an employee of long tenure leaves the Department. (*Conclusion #3*)

The Gas Supply Department should develop a comprehensive training program to serve as a guide for training new employees, and for providing cross-training to existing employees. Western must be confident that a program is in place to provide for the ongoing knowledge transfer from the existing employees of long tenure with the Department to newer employees, such that mechanisms are in place to ensure continuity of knowledge and activities when these employees do leave Atmos.

3. Gas Supply Management

a. Scope

- Existing Gas Supply Portfolio
- Supplier Identification and Qualification
- Identification of Acquisition Needs
- Negotiation and Re-negotiation of Contracts
- Contract Terms and Conditions
- Peak Period Performance
- Price Risk Management

b. Background

(1) Existing Gas Supply Portfolio

WKG's distribution system was developed along the routes of the Texas Gas Transmission Corporation's and Tennessee Gas Pipeline Company's interstate gas transmission systems. As a consequence, much of WKG's capacity portfolio consists of contracts on those two pipelines. In recent years, WKG has added relatively small amounts of capacity on the Trunkline Gas Company and Midwestern Gas Transmission Company systems. Trunkline passes on the west side of the Company's service territory in and around Paducah, KY, where the Company was experiencing growth in its load. The capacity on Midwestern was added to provide peak-period delivery capacity to the Owensboro area . WKG's capacity and supply portfolio is presented in Table 3.1, below.

Table 3.1 Transportation & Storage Capacity*

Company:	Texas Gas Pipeline					Tennessee Gas Pipeline					Trunkline Gas P/L	Midwester n P/L
Type:	NNS Transport	FT Transport	SFT Transport	IT Transport	Grand Total	FT-GS Transport	FT-G Transport	IT Transport	Grand Total	FS Service-ACQ	FT Transport	FT Transport
										1,313,538		
Jan	140,000	18,500	12,500	120,189	291,189	8,088	33,229	40,000	81,317		8,000	10,000
Feb	140,000	18,500	12,500	120,189	291,189	8,088	33,229	40,000	81,317		8,000	10,000
Mar	140,000	18,500	12,500	120,189	291,189	8,088	33,229	40,000	81,317		8,000	10,000
Apr	126,205	18,500	-	120,189	264,894	8,088	27,700	40,000	75,788		8,000	10,000
May	94,292	18,500	-	120,189	232,981	8,088	18,500	40,000	66,588		2,200	10,000
Jun	94,292	18,500	-	120,189	232,981	8,088	13,500	40,000	61,588		2,200	10,000
Jul	94,292	18,500	-	120,189	232,981	8,088	13,000	40,000	61,088		2,200	10,000
Aug	94,280	18,500	-	120,189	232,969	8,088	13,000	40,000	61,088		2,200	10,000
Sep	94,292	18,500	-	120,189	232,981	8,088	16,000	40,000	64,088		2,200	10,000
Oct	131,161	18,500	-	120,189	269,850	8,088	23,500	40,000	71,588		8,000	10,000
Nov	140,000	18,500	12,500	120,189	291,189	8,088	33,229	40,000	81,317		8,000	10,000
Dec	140,000	18,500	12,500	120,189	291,189	8,088	33,229	40,000	81,317		8,000	10,000
Total	1,428,814	222,000	62,500	1,442,268	3,155,582	97,056	291,345	480,000	868,401	1,313,538	67,000	120,000

* All volumes Dth/Day except ACQ

The American Louisiana segment of ANR Pipeline Company's transmission system passes through the heart of WKG's Texas Gas service territory. WKG has two interconnects with

ANR, that it uses for storage fill only. WKG solicited a proposal from ANR for the requirement that resulted in the Midwestern contract, but ANR did not have the capacity available at the times of the year when WKG needed it.

WKG also has five on-system storage facilities. The operational characteristics of those facilities are presented in Exhibit 3.1, on page 3. WKG's on-system storage provides 80,000 Mcf/day of peak-day delivery capacity, but that capacity is of limited duration. Hence, WKG also uses No-Notice Service on both Texas Gas and Tennessee Gas Pipeline, in order to provide seasonal storages with more extended withdrawal capabilities.

The configuration of WKG's distribution facilities is a collection of unconnected links to the interstate transmission systems, with little interconnection behind WKG's city gates. Thus, WKG has little ability to move gas supplies from one part of its distribution system to another. In fact, WKG requires aggregation of its requirements across its Texas Gas delivery points in order to access the full re-delivery capacity of its storage facilities.

The bulk of WKG's commodity supply is provided under a Natural Gas Sales, Transportation and Storage Agreement between WKG and Woodward Marketing, L.L.C. Under this agreement, WKG makes Woodward its agent for the operation of its pipeline capacity, and allows Woodward to operate WKG's on-system storage facilities. For its part, Woodward undertakes to supply all of WKG's requirements, when, as and where WKG experiences them. The balance of WKG's commodity supply is acquired from local producers, who sell gas directly into WKG's distribution system.

(2) Supplier Identification and Qualification

The parent company's Gas Supply Department (*Gas Supply*), which conducts supply-contracting activities for all five of Atmos's operating divisions, maintains bidders lists. WKG's list is a combination of bidders with whom WKG has previously done business, (maintained and updated as necessary), and additional bidders who have met credit qualifications and who either have done business with other Atmos divisions, or have requested to be put on WKG's bidders list. WKG's list is updated for each WKG solicitation.

Gas Supply has a bidder qualification process, but it is not formalized. The process begins with experience with a prospective bidder somewhere among the Atmos companies. Atmos then checks financial background and trade references. Qualified bidders are put on lists for the divisions for whose requirements they want to compete.

EXHIBIT 3.1
WKG STORAGE FIELD OPERATIONAL PARAMETERS

Bon Harbor
- Cycle full working gas capacity

- Water Drive Reservoir
- Working Gas Capacity = 778,660 MCF
- Injection: 12,000 MCFD
- Withdrawal: 15,000 MCFD
- Inject early in the season after withdrawal. Keep the field on-line as much as possible. Do not allow field to sit stagnant for long periods of time. Prefer one (1) month maximum shut-in time.

Grandview

- Cycle full working gas capacity
- Inject early in the season for a couple of days if possible to dry out wellbores. No other restrictions.
- Working Gas Capacity = 250,000 MCF
- Injection: Max = 3,600 MCFD, Min = 1,000 MCFD
- Withdrawal: Max = 4,000 MCFD, Low End = 2,000 MCFD, 30 Day Avg. = 3,000 MCFD; Gas is compressed out when the field pressure and flow rate drop off.

Hickory

- Cycle full working gas capacity
- Inject early in the season for a couple of days if possible to dry out wellbores. No other restrictions.
- Working Gas Capacity = 450,000 MCF
- Injection: Max = 15,000 MCFD, Min = Not Applicable, gas is free flowed in.
- Withdrawal: Max = 18,000 MCFD, Low End = 6,000 MCFD, 30 Day Avg. = 8,000 MCFD

Kirkwood

- Cycle full working gas capacity
- No injection restrictions.
- Working Gas Capacity = 200,000 MCF
- Injection: Max = 5,000 MCFD, Min = 4,000 MCFD with compressor, not applicable when free flowing from ANR.
- Withdrawal: Max = 10,000 MCFD, Low End = 3,000 MCFD, 30 Day Avg. = 5,000 MCFD

St. Charles

- Cycle full working gas capacity
- No injection restrictions.
- Working Gas Capacity = 2,600,000 MCF
- Injection: Max = 18,000 MCFD, Min = 12,000 MCFD
- Withdrawal: Max = 40,000 MCFD, Low End = 15,000 MCFD, 30 Day Avg. = 27,000 MCFD; Gas can be compressed out towards the low end at a rate of about 19,000 MCFD.

Totals:

Max Daily Withdrawal	94,000	MCFD
Withdrawal 30 Day Avg.	53,000	MCFD
Withdrawal @ Low End	37,000	MCFD
Working Gas Capacity	4,250,000	MCF
Max. Daily Injection	26,000	MCFD when compressing
Min. Daily Injection	N/A	when free flowing

In discussions with Atmos's Gas Supply personnel, Liberty observed that the range of potential competitors for providing supply in field markets is considerably broader than that for providing combined supply and asset-management services at WKG's city gates. Atmos's response was that the Company does not prohibit firms from teaming for the purpose of bidding for Atmos's business, and indeed the current contractor, Woodward Marketing, has teamed with a large gas supplier to compete for the new contract. Atmos is concerned about consolidation among, and the weakened financial condition of, wholesale market competitors, and the Company does what it can, consistent with the public-service obligations of its operating divisions, to encourage firms to compete for its business.

(3) Identification of Acquisition Needs

As noted earlier, requirements estimation is done by Atmos's Gas Supply Department in Dallas. Peak-day deliverability from WKG's on-system storage, plus its contracted No-Notice services, are subtracted from its peak-day capacity requirements, and the result is compared to the remaining available peak-day capacity (mostly Firm Transportation, or FT). If a deficiency results, additional capacity is sought. The process must be done separately for the Texas Gas and Tennessee Gas portions of WKG's service territory, as there is little capacity to move gas between the two.

The connection to Trunkline was added for operational reasons. The Paducah area had been served from Texas Gas, but the load growth in that area was away from that source. Adding the connection to Trunkline provided another feed from the other side of the load. The new connection was initially for more capacity than the current contract, but WKG found that it did not require the larger amount.

For commodity, the Company's Natural Gas Sales, Transportation and Storage Agreement provides almost all of the Company's supply, delivered to its city gates. (The balance is provided by local production.) WKG's practice has been to make the term of those agreements match the term of its performance-based ratemaking plan, which has been four years. The term of the currently effective agreement is a little over three years, because the company originally selected to perform as WKG's agent found after about one year that it could not meet the terms of the contract, and paid to settle it. The replacement contract was structured to coincide with the remaining term of the Company's PBR plan. Thus, until recently, the Company had not "been to the market" in several years.

(4) Negotiation and Renegotiation of Contracts

Similar to most other LDCs, WKG came out of the Order 636 process with approximately the amounts of pipeline and storage capacity that the pipeline companies had been using to serve its requirements prior to that time. WKG's customer numbers have been growing, but the decline in use per customer is offsetting that growth. Since Order 636, WKG has added the Midwestern connection, which is primarily a peaking resource, and has adjusted its Texas Gas contracts somewhat.

As noted earlier, WKG requires some flexibility in its nominations on the Texas Gas system, in order to allow full access to its on-system storage. WKG has been able to work with Texas Gas to obtain that flexibility, and feels that it has a good working relationship with Texas Gas. WKG has had recent negotiations with both Texas Gas and Tennessee Gas over a number of matters, including implementation of the FERC's Order 637, and feels that it has no outstanding issues with either pipeline at this time.

WKG's agency agreement with Woodward covers about 98 percent of its commodity supply. For the two percent that comes from local production, WKG uses month-to-month contracts, with the exception of a few contracts with two-year terms. Consequently, there is little need to re-visit any of these contracts; rather, the Company waits for them to expire if necessary.
WKG has made some adjustment of its capacity contracts in response to changes in its load, but those changes have been forthcoming.

(5) Contract Terms and Conditions

WKG's contracts for capacity are service agreements pursuant to FERC Gas Tariffs. Thus, those service agreements are governed by the terms of those Tariffs.

For commodity, WKG generally uses a form contract with general terms and conditions, plus an "Exhibit A" that contains the particular terms of each purchase arrangement. Particular terms include price, daily and annual purchase volumes, and receipt and delivery points. WKG's agreement with Woodward also covers the sharing of capacity-release revenues, and certain rights and responsibilities that both parties have in the management of WKG's pipeline capacity and storage facilities.

In other divisions, Atmos has tried competing its requirements for gas supply separately from its requirements for asset-management services. Atmos reports that the combination approach yields better results.

Atmos's Legal Department has a Contract Administration section that assists Gas Supply in finalizing purchase contracts. Contract Administration maintains the contract files for all of Atmos's operating divisions.

(6) Peak Period Performance

As noted in the discussion in Task Area One – Gas Supply Planning, Liberty's assessment is that WKG is slightly deficient on peak-day supply capacity. While no delivery failures occurred, Woodward also noted recently that some of its delivery capacity (not under contract to or owned by WKG) was required in January, 2001, in order to alleviate a low-pressure situation in WKG's Owensboro service area. All delivery obligations were met, however.

(7) Price Risk Management

WKG has traditionally hedged its winter-period gas costs by buying gas during the summer and injecting it into storage. This storage is both Company-owned storage and capacity under contract from the Company's pipeline suppliers. The quantity hedged in this manner amounts to about half of the Company's winter-period requirements. The Company does not sell gas to any customer class under a fixed-price option, nor does it provide any other unconventional gas-supply options to its customers.

For the winter of 2001/2002, the Company also used futures contracts to protect against price spikes, such as had been experienced the previous winter. Futures contracts were purchased during the April-to-October period of 2001, for gas to be delivered during the succeeding November through March. As the Company already had its full requirements under contract, the futures contracts were used purely as a price-risk management device, with no physical delivery taken under those contracts. The quantity covered by the financial hedging program was 4.7 Bcf, or about 25 percent of the Company's winter-period requirements.

Prices for natural gas declined over the course of 2001. Consequently, WKG's financial hedges, like those of the other Kentucky LDCs that engaged in hedging in that year, cost its customers money. WKG's Hedging Report, filed March 22, 2002 in Case No. 2002-00093, reported that the average price of the hedged volumes was $3.66 per MMBtu. As a result, WKG's financial hedging program added $5.7 million to its gas costs over the period, or about 30 cents per MMBtu.

c. Conclusions

(1) WKG's gas supply management has produced good results.

According to GCA data on file with the Commission, WKG's gas costs are consistently among the lowest in the State. While WKG has the advantage of on-system storage, its gas costs have consistently compared favorably with the other Kentucky LDC with that advantage, LG&E. On-system storage is an advantage in comparisons of gas costs because the costs of that storage are included in non-gas costs, rather than in gas costs. Thus, other things being equal, gas costs would be lower for a company with on-system storage than for one that acquired all of its storage off-system.

(2) WKG's bidding procedures should be improved to avoid affecting the competition for managing its gas-supply operations. *(Recommendation #1)*

As noted in the discussion in Task Area One – Gas Supply Planning, Liberty is concerned that WKG's capacity portfolio may not be a good fit for the Company's system-supply load. A more appropriate capacity portfolio could include more peaking capacity, and possibly less pipeline capacity. There are restrictions on deliveries to individual city gates in Texas Gas's FERC Gas Tariffs, and in its Service Agreements with each of its customers, including WKG. If those restrictions are not enforced, as is the case now, WKG can get by with less capacity on Texas Gas. In a business environment of tightening pipeline operating conditions, however, it seems prudent to expect that those restrictions may begin to be enforced in the not-too-distant future. In that event, WKG needs almost all of the capacity currently under contract in order to meet its delivery obligations under Liberty's Test Case Weather scenario. (See the further discussion of Liberty's Test Case Weather scenario in Section I of this report.)

Liberty is concerned that the level of knowledge that bidders have about WKG's system-supply load could affect the competition to replace WKG's supply manager. In its recent request for proposals (RFP) to replace WKG's current supply-management agreement, Atmos's Gas Supply Department included monthly estimates of WKG's requirements for supply, but did not include information regarding the specific nature of WKG's load – information such as base load and use factors, service-area HDD data, etc. Liberty's concern is that a bidder who knew more about WKG's load than was contained in the RFP might bid differently from one who did not. Thus, as the RFP was structured, incumbency could have provided an advantage in the bidding.

Liberty examined this situation in considerable detail, and found that as the bid evaluation process developed, additional specific load information was provided to the bidders in response to their questions. In the final analysis, Liberty felt that the selection process was not compromised because of the initial omissions in the RFP. In the future, however, the bidding procedures must be improved.

(3) WKG's hedging program needs more study. *(Recommendation #2)*

As noted in the first section of this report, Liberty is concerned that the Commission's interest in gas price stability has not yet been reconciled with its interest in low prices. Thus, while WKG's hedging program for '01/'02 was clearly consistent with guidance given by the Commission, and was approved by the Commission, it resulted in prices that were above market prices. Again, as previously discussed, Liberty believes that the Commission, the LDCs and other interested parties should work together to establish objectives for the companies' hedging programs as part of their evaluation of the pilot programs conducted for the winters of '01/'02 and '02/'03.

d. Recommendations

(1) In future years, Atmos's Gas Supply Department should implement improved bidding procedures. *(Conclusion #2)*

As discussed in Conclusion 2, Liberty is concerned that the incumbent provider of gas supply and supply-management services has knowledge about WKG's load that other potential competitors were not provided in a timely way. Liberty believes that this additional knowledge could have affected bidding strategies.

Liberty believes that WKG's customers will suffer at some point in the future if the competition to provide gas supply and supply-management services is perceived as unfair. If competitors learn that one of the bidders had knowledge that the others did not, they could decline to bid in the future. Vigorous competition on a "level playing field" is necessary to ensure that WKG's customers get the most favorable terms possible.

Given the currently weakened financial condition of the firms who could provide the supply-management services that WKG seeks, and given current conditions in gas markets, Liberty does not believe that a new competition for the supply-management agreement would produce a result that is better for customers than the competition that is nearly complete. In fact, Atmos' Gas Supply Department is concerned that a new competition might result in worse terms than were proposed when the bids were due in late April. Consequently, Liberty recommends that WKG implement new and improved bidding procedures the next time that the Company goes to the market for gas supply and supply-management services, approximately four years from now.

Liberty's recommendations about the improvements necessary for all of the procedures associated with natural gas procurement and supply management are detailed in Task Area Two–Organization, Staffing and Controls. Specific elements of bidding procedures that Liberty found lacking in the recent bidding process included requirements for bidder's meetings, requirements for comprehensive detail in the original RFP, and procedures for notification of all bidders when questions from one bidder are answered.

A specific point to be added here is Liberty's concern that the four-year term that WKG has been using for its supply-management contracts may be too long. Liberty's particular concern is that load conditions, market conditions, pipeline operating conditions, and the financial condition of potential competitors, are all in a state of flux now, and may still be changing four years from now. Ensuring maximum benefit to WKG's customers, in our view, requires testing the markets more often than once every four years. Perhaps more importantly, assuring vigorous competition for WKG's business requires frequent communication to potential competitors that WKG is interested in that competition.

Liberty is aware that a longer-period relationship has material benefits for suppliers, and that a share of those benefits for customers may show up in the form of better terms for a longer contract. Liberty's suggestion is that the better-terms possibility be evaluated through competitive bidding. When WKG next goes to market for supply-management services, it should ask for proposals for two-, three- and four-year periods, and then evaluate whether the difference in proposed terms provides sufficient benefit to warrant the longer-period relationship.

(2) WKG should work with the Commission, the other Kentucky LDCs and other interested parties to establish a common foundation of objectives for natural gas hedging programs. *(Conclusion #3)*

As discussed in the first section of this report, Liberty believes that the Commission, the LDCs and other interested parties should pause after next winter to review the results of the pilot hedging programs conducted for the winters of '01/'02 and '02/'03. The three LDCs with '01/'02 programs used different techniques to stabilize prices of their supplies. Also, Atmos used different hedging techniques in other States in which it operates. The Columbia Distribution Companies, whose gas-supply operations are also conducted on a centralized basis, had hedging programs in three of the five States in which they operate. (Kentucky is one of the five, but not one of the three.) Thus, among companies with interests in Kentucky, there is a considerable body of experience with price-risk management.

Liberty recommends that a specific area for discussion be the objectives of future hedging programs. In this vein, Liberty applauds the Commission's adoption of the Attorney General's suggestion, presented in the context of consideration of ULH&P's proposed hedging program for '02/'03, that public input be sought in selecting those objectives. Western has included a related question in a survey of its customer attitudes. Our experience tells us that different customer classes will prefer different objectives. That knowledge will help the Kentucky LDCs to tailor their service offerings more closely to their customers' requirements.

4. Gas Transportation

a. Scope

This chapter addresses WKG's natural gas transportation and related services. Aspects of those services include the following:

- Transportation Programs Offered
- Agency Programs
- Bypass Issues
- "Prodigal Son" Customers.

b. Background

(1) Transportation Programs Offered

WKG primarily offers four transportation services, T-2/G-1, T-2/G-2, T-3 and T-4. Each of these services is available to any customer with expected consumption of 9,000 Mcf/year or more.

T-2 service is coupled with a stand-by sales service – G-1 for firm stand-by service, and G-2 for interruptible. Customers for these services may choose to take any or all of their supply as a sale – any monthly imbalance resulting from consumption in excess of nominated transportation supply is the amount of sales service taken. Under heavy system load conditions, however, WKG may impose daily balancing restrictions (Operational Flow Orders, or OFOs) that require customers to maintain a balance between their usage and deliveries from their suppliers.

T-3 transportation service is interruptible service with no back-up supply. If a customer has a negative imbalance at the end of a month (consumption exceeds nominated supply), the customer is assessed over-run penalties. Moreover, under OFO conditions, daily balancing is required. Finally, T-3 service can be interrupted by WKG if necessary.

T-4 transportation service is like T-3 except that the service is firm. Quantities nominated by the customer and delivered to one of WKG's city-gate receipt points will be re-delivered to the customer under essentially any load conditions.

WKG also has T-1 and T-5 transportation services. T-1 is a Storage Transportation Service that applies to customers who have their own storage facilities connected to WKG's distribution system. A charge applies for transportation both to and from the customer's storage facility, and the service is interruptible. T-5 service provides a framework under which transporters may access an alternative pipeline in addition to their traditional interstate carrier into Western's system. T-5 is a "best-efforts" service, in order to preserve access to those other pipelines for WKG's system-supply customers.

Rates for WKG's firm transportation services are the same as the non-gas component of its sales-service rates, which decline as the customer's volumes increase. WKG has 19 special contracts with large-volume customers that provide for negotiated rates. Transportation-service customers provide their own pipeline capacity, which is usually managed for them by a marketer acting as their agent.

Table 4.1 gives the number of customers and volumes transported for WKG's transportation services over the last three fiscal years. In addition to the data in the table, WKG reports movement under the T-1 rate of 22,566 Mcf in fiscal year 1999, 22,702 Mcf in FY 2000, and none in FY 2001.

Table 4.1 Transportation Customers and Volumes

	T-2/G-1		**T-2/G-2**		**T-3**		**T-4**		**Total Transportation**	
Period	Cust	Volume	Cust	Volume	Cust	Volume	Cust	Volume	Cust	Volume
FY 1999	7	135,979	8	616,394	65	15,939,680	77	8,798,670	157	25,490,723
FY 2000	5	60,434	5	269,125	65	15,290,851	83	9,884,200	159	25,504,610
FY 2001	7	47,483	7	437,449	65	13,546,210	86	9,186,161	164	23,217,303

Notes: FY ends September 30.
"Customer" counts for annual periods represent the average number of customers. Customers using a combination of transportation services during a given month are shown under their primary transportation service. All volumes are in standard Mcf.

(2) Agency Programs

WKG does not have its own agency program, as there are a number of marketers (12) that are active in its service territory. In addition to providing supply to WKG's transportation-service customers, the marketers act as their customers' agent for pipeline nominations and scheduling. WKG is a confirming party for their nominations, which it does as part of maintaining control over movements on its system.

(3) Bypass Issues

Bypass is a constant threat for WKG because of the location of its service territory, along "pipeline alley". Pipeline alley is an industry term used to refer to an area traversed not only by the five pipelines that serve WKG, but also close to main lines for the Texas Eastern and Columbia Gulf Transmission systems. WKG's load has always been 50 to 60 percent industrial, much of which is large-volume customers, for which bypass economics are generally the most favorable.

WKG has avoided bypass by offering well-designed services at low rates. WKG began to offer gas transportation service in 1984, well before the FERC's Order 436, itself over six years before Order 636 (the latter order providing broad access for large-volume customers to the interstate transmission system). As noted above, WKG's rates for transportation service are based on fully-allocated costs. WKG switches to a special contract rate if necessary to maintain the load.

(4) "Prodigal Son" Customers

WKG reports that, once a customer has left sales service for transportation, the customer almost never comes back. Occasionally a smaller-volume transportation-service customer will decide that the savings available through direct purchases are not worth the extra trouble, and will come back to sales, but that circumstance is rare. The attraction of direct-purchase arrangements is flexibility: customers can work with marketers to design gas-supply arrangements that suit their particular interests and circumstances.

c. Conclusions

(1) WKG's gas transportation program is efficient and effective.

WKG operates a very successful transportation program in very competitive circumstances by offering well-designed transportation services at competitive prices. The attention that WKG gives to its customers and services is important, but perhaps its best competitive weapon is WKG's extremely low cost structure. WKG's non-gas costs, which are the basis for its transportation rates, have long been the lowest in Kentucky, and are among the lowest in the United States.

(2) WKG works at protecting the interests of system-supply customers.

First, and most importantly, WKG's rates for transportation services are based on fully-allocated costs. The Distribution Charge for High-Priority Service under WKG's General Transportation Service (Rate T-2) is the same as the Distribution Charge for the Company's General Firm Sales Service (Rate G-1), for example. Rates are lower for lower-quality services, and must be discounted in competitive situations. WKG does what it can, however, to recover some fixed costs even in competitive situations.

Transportation customers are also assessed a proportionate share of lost-and-unaccounted-for volumes (LAUF). Another sign of WKG's concern for system-supply customers is the T-5 rate. Conditions on the availability of this service limit the ability of transportation-service customers to pre-empt access to low-cost gas supplies that might become available on one of WKG's non-traditional pipelines (ANR, Midwestern and Trunkline).

A fourth indicator of WKG's concern for all of its customers, both sales-service customers and transportation-service customers is the Company's effort – discussed in more detail in the next chapter of this section – to adjust its tariffs in response to changes in pipeline operating conditions. These changes may have the effect of requiring WKG to assist some of its customers in balancing their loads. The focus of WKG's efforts to adjust its tariffs is to ensure that any costs that it incurs in providing that assistance is passed on to the customers that cause them, as opposed to spreading those costs over all of its customers.

d. Recommendations

None

5. Gas Balancing

a. Scope

This chapter addresses WKG's strategies and programs to achieve a balance between the amounts of gas that come into its system with the amounts that it delivers to its customers. Aspects of those strategies and programs include the following:

- Metering and Testing
- Balancing Strategies and Practice
- Assignment of Capacity to Third Parties

b. Background

(1) Metering and Testing

WKG's approach is to meter everything. Small-volume sales-service customers' meters are read monthly, but larger-volume customers meters are read continuously. All company-use gas is metered; none is estimated.

WKG tries to read the meters measuring amounts of gas coming into its system (city gates) at the same time of day as it reads amounts going out at customer meters. The purpose of this practice is to reduce possible measurement differences due to variations in patterns of customer use.

Lost-and-unaccounted-for volumes (LAUF) are determined by comparing the sum of meter readings going into WKG's system to the sum of measurements going out. As the Company's small-volume customers are metered monthly, the comparisons must allow for meter-reading schedules. Comparisons are made on a 12-month rolling-average basis, with a summer (low-use) number used for the billing factor used in the tariff.

As WKG's system is composed of mostly unconnected segments, these comparisons are made on a segment-by-segment basis as much as possible. The Company's local operations at the town level participate in the review of LAUF levels, as monitoring LAUF rates is an important part of WKG's leak-detection efforts.

WKG uses statistical sampling of all meter classes in its meter-testing program. That program was presented to and approved by the KYPSC in Case No. 1999-059.

(2) Balancing Strategies and Practice

WKG's largest customers are metered with electronic flow measurement (EFM) devices, and the results are telemetered into WKG's offices. Smaller-volume transportation-service customers are metered continuously, but the results are not telemetered in. Metering data is put onto a web site as it becomes available, in order that large-volume users can adjust their nominations as necessary to keep their nominations and usage in balance.

Nominations for transportation-service customers are generally submitted to the pipelines by each customer's supplier (a marketer), acting as the customer's agent. While the supplier's nomination to a pipeline may cover multiple customers, WKG, in its confirmation and acceptance of the supplier's nominations, requires that those nominations be disaggregated to the individual customer and delivery point level, in order that WKG might track the relationship between each customer's nominations and its usage, on both a daily and monthly basis.

Imbalances are tracked monthly for billing purposes. During OFO conditions, the balance between nominations and usage are monitored daily in order to maintain system control and deliveries to all customers.

WKG does not now provide a separate balancing service. WKG's configuration as a collection of discrete sub-systems, connected to different pipelines, would make it difficult to balance large customers' requirements other than on a customer-by-customer, delivery-point-by-delivery-point basis. The Company is watching developments in pipeline operating conditions, however, and considering whether specialized balancing services may be required.

(3) Assignment of Capacity to Third Parties

Under the Natural Gas Sales, Transportation and Storage Agreement relationship that WKG uses to manage its gas-supply resources, the Company designates its asset manager as its agent under its contracts for gas transportation and storage services. Its agent is then responsible for all nominations, capacity-release notices, etc., for WKG's capacity and its load to the operators of those facilities (generally, the pipeline companies). The agent may release some capacity temporarily, when it is not required to serve WKG's load, but WKG is not involved in those transactions.

WKG's transportation-service customers provide their own pipeline capacity, which is typically administered for them by their suppliers, acting as their agents. WKG has never held pipeline capacity for these customers, as they bought only interruptible sales service from WKG in the days before they had access to their own pipeline capacity.

c. Conclusions

(1) Measurement is a priority at WKG, and the Company's results demonstrate the benefit of this attention.

WKG's LAUF is the lowest among the five Kentucky LDCs studied for this project. The proportion used in the Company's current billings is 1.09 percent. The lowest proportion among the other four LDCs is about two percent, and others are in the vicinity of four percent.

WKG's attention to measurement is driven by the nature of its load, with 50 to 60 percent being large-volume industrial customers where relatively small measurement errors can have large-dollar consequences. The Company's focus on measurement has made it a leader in this area, both in Kentucky and across Atmos.

(2) WKG is studying the consequences for its system of changes in pipeline operating conditions. *(Recommendation #1)*

The trend that WKG is watching is the effort by pipelines to accommodate more customers without expanding capacity. Often those new customers are natural-gas-fired electricity-generating facilities. Of the pipelines serving customers in Kentucky, Texas Gas is perhaps the most aggressive about these matters, as it has a number of new electricity-generation customers.

The change that is driving the effort is limits on variation in hourly flow, perhaps leading to hourly (as opposed to daily) balancing. The study effort is Atmos-wide, rather than just WKG, as it presents broad issues about instrumentation and managing measurement and control data. Atmos has recently updated its System Control and Data Acquisition (SCADA) system, and implementation of the full capabilities of the new system is continuing.

d. Recommendations

(1) The Company should inform the Commission about the issues surrounding pipeline operating conditions, and the potential consequences of those issues for LDC customers. *(Conclusion #2)*

While Texas Gas is perhaps "out front" on evaluating changes to pipeline operating conditions because of relatively limited capacity and the siting of an unusual number of new electricity-generating facilities along its route, Liberty expects that more pipelines will be seeking these types of changes in the not-too-distant future. Accordingly, Liberty is concerned that the Commission be informed about the changes, and their potential consequences for LDC customers.

As a means of informing the Commission about the changes, Liberty recommends that WKG prepare a short report, or present a briefing on this subject for the Commission Staff. If the Company feels that Commission involvement in deliberations at the FERC on these matters would be helpful, it could request some such involvement at that time.

6. Response to Regulatory Change

a. Scope

This chapter addresses WKG's responses to the changes in the operating environment that have been caused by changes in regulation of the gas industry since the late 1980s. Aspects of those responses include the following:

- Changes in Objectives for Supply
- Changes in Supply Activities
- Capacity Cost Reduction.

b. Background

(1) Changes in Objectives for Supply

WKG's parent company's principal objective in its administration of the gas-supply function is the same as its principal objective in all other aspects of its business which is to deliver high-quality service at the lowest possible cost. What has changed with the changes in the Company's regulatory and business environment is how the parent has pursued that objective in the conduct of its supply function.

The FERC's Order 636 moved responsibility for the "merchant" function -- buying gas in field markets and transporting it to the city gate – from the pipeline segment of the gas industry to the distribution segment. Atmos has developed its own way of administering that function. Atmos' approach involves focusing its activities on presenting its customers' requirements at the city gate, and then managing its distribution system to ensure reliable deliveries from its city gates to its customers.

Supply activities upstream of Atmos's city gates – the acquisition of gas supply in field markets, and the management of pipeline and storage capacity involved in getting the supply to its city gates – have been out-sourced as much as possible. In the case of WKG, the Company in 1996 entered into an agreement with a supplier "… to enhance the value of Western Kentucky Gas Company's natural gas storage and transportation rights." In 1998, that agreement was replaced with arrangements that became WKG's recently-expired Natural Gas Sales, Transportation and Storage Agreement.

Under the latter agreement, WKG appoints the contractor as its agent for management of all of WKG's transportation and storage contracts. WKG also has the contractor nominate WKG's on-system storage facilities. Further, the contractor provides all of the gas supply required by WKG's sales-service customers, including quantities injected into storage.

WKG's contractor is free to manage and use all of WKG's gas-supply resources as it sees fit within operational parameters, as long as WKG's requirements for supply at its city gates are met. The contractor agrees to provide supply to WKG at a discount to the composite price index that is used in WKG's performance-based rate mechanism (PBR). Under that mechanism, WKG and its customers split the discount. WKG and its customers also split 90 percent of any revenues generated by secondary-market activities involving supply resources under contract to WKG.

Atmos uses similar arrangements everywhere that it can. At last report, Atmos had four other "agency" agreements, involving service territories in Kansas, Missouri, Louisiana, Tennessee, Virginia and Georgia. Atmos reports that it has experimented with variations on these arrangements, but finds that the agency arrangement works best.

(2) Changes in Supply Activities

Liberty reported earlier in Chapter 2 that Atmos's own gas-supply activities are three-fold:

- Gas supply planning: forecasting customers' gas requirements and conducting competitions to provide those requirements;
- Nominations and scheduling: monthly and intra-month notification to suppliers of system-supply customers' requirements, and of transportation customers' nominations; and
- Gas control: monitoring, balancing and control of deliveries to the Company's city gates, and from those points to its customers.

As also noted, these activities are conducted on a shared-services basis for all of Atmos's divisions. Gas Supply Planning is located in Dallas, and the other two functions are located in Franklin, Tennessee.

As well as having tried to improve its upstream arrangements through experimentation, Atmos has worked to improve its own activities. As also reported in Chapter 2, an amazingly small number of people (22) manage the supply activities of Atmos's five divisions, which involve 35 pipelines and 1.4 million customers. Another position has been authorized for the Gas Supply Planning area, to focus on peak-load forecasting.

(3) Capacity Cost Reduction

In the typical business arrangements for the conduct of the gas-supply function, LDCs engage in secondary-market transactions – off-system sales and capacity-release transactions – in order to generate margins that can be used to offset the costs of maintaining pipeline and storage capacity under contract. Most LDCs have pipeline capacity that is required to serve their customers on peak days, but is available for other uses on other days. In Atmos's case, the agent conducts the secondary-market transactions. The customers' share of the benefit of those transactions comes in the form of a discount on the price of the commodity supplied to the division's city gates as well as a sharing of the revenues from the capacity released by the agent. Indeed, WKG's recently-expired Sales, Transportation and Storage Agreement worked this way.

In the conventional business model, margins from secondary-market activities are helpful in carrying the costs of the necessary capacity, but are not sufficient to cover fully the costs of excess capacity. In other words, it costs the customers money if an LDC carries extra capacity for the purpose of increasing secondary-market activities.

The Atmos model's performance is the same on this point. While the commodity-price discounts and sharing of capacity release credits are helpful in paying capacity costs, they do not cover those costs fully. Thus, full advancement of customers' interests requires eliminating any excess capacity.

As noted earlier in Chapter 3, Gas Supply Management, relinquishing pipeline capacity is a risky proposition for WKG if the capacity might be needed in the near future to accommodate load growth, or changes in pipeline operating conditions. Potential competition for pipeline capacity in the future is not sufficient justification for maintaining an unreasonable amount of excess capacity, however. The balance that is required between retaining a reasonable amount of capacity to accommodate load growth, and relinquishing capacity that is clearly in excess of the Company's requirements, places a premium on careful estimation of both load-growth possibilities, and of the amounts and types of capacity that are required to serve current customers. As noted in Chapter 1 of this section, Liberty feels that load forecasting needs increased emphasis within Atmos's Gas Supply Department.

WKG, like most LDCs, is using about the same amounts of capacity that it was assigned in the FERC Order 636 implementation process. Connections to ANR, Midwestern and Trunkline have been added since that time, however. Atmos reports that there has been some adjustment in its contract levels on Texas Gas.

c. Conclusions

(1) Atmos conducts its gas-supply function pursuant to a business model that is different from other LDCs.

As is suggested by the discussion above, suppliers compete to provide a product to Atmos's operating divisions that is different from the one provided to most other LDCs. For most LDCs, suppliers compete to provide a commodity delivered to a receipt point, located in a gas-producing region, on a pipeline on which the customer (the LDC) holds capacity. For Atmos's divisions, the supplier is competing not only for the right to provide supply, but also for the right to manage a division's pipeline and storage assets. In the conventional model, the location of the competition is a producing area; in the Atmos model, the location of the competition is the division's city gates.

(2) The Company's business model involves risks that are different from those in the conventional model. *(Recommendation #1)*

As we noted in Chapter 3, the pool of potential suppliers to a production-area receipt point is vastly larger than the pool of potential suppliers to WKG's city gates. Field markets may have literally hundreds of participants who are capable of providing a readily-available commodity to any number of pipeline receipt points. The number of competitors who can combine the commodity with the ability to manage pipeline and storage capacity is much smaller. Suppliers of the commodity still compete for the right to provide supply, but that competition is conducted by the agent, not by WKG.

WKG's contract is with the agent, not with the suppliers. All terms of WKG's contract are negotiated between WKG and the agent; the contract is unique to that relationship. Thus, rather than conducting a competition for a commodity, that can be provided by perhaps hundreds of competitors, pursuant to terms that are standardized across thousands of transactions, WKG conducts a competition for a service, that can be provided by a much smaller number of competitors, pursuant to terms that are unique to the particular relationship.

The much-thinner market at the city gate gives rise to business risks that are different from those in the conventional model. Among those different risks are the following:

- <u>Counter-party risks.</u> The number of competitors that can perform the services that the new model requires is smaller than the number that can supply gas. Moreover, the competitors that are in business to perform those services are ones that are currently having considerable financial difficulty (Enron, Dynegy, Mirant, etc.). WKG's original choice for its 1998 supply services agreement, for example, could not perform.
- <u>Failure to supply.</u> If there is a failure to supply, it occurs at a less-liquid location (WKG's city gates). Thus, WKG's ability to access its pipeline capacity in the event of a failure is critical.

A delivery failure in a producing area is a disappointment, but hardly a crisis, as there are likely to be hundreds of other suppliers available to fill the need. Supplier failure at a city gate could be much more serious. The pipeline capacity provided to the supplier in its agency role could be committed to another customer. Gas in storage for winter-period delivery to an LDC could be seized by one of the supplier's creditors in response to a failure elsewhere. The firms that contract to provide city-gate services often have little in the way of independent assets that might be used to guarantee their performance.

While the Atmos business model does create these risks, it is only fair to acknowledge the benefits as well as the risks of this business model. For example, the Atmos business model has consistently resulted in gas costs and non-gas costs that are among the lowest in Kentucky and the nation. This is discussed more fully in both Chapters 3 and 4.

d. Recommendations

(1) WKG should work with the Commission to help it understand the risks in the parent company's business model, and how the Company is dealing with those risks. *(Conclusion #2)*

Liberty expects that Atmos is fully aware of these risks, and that it takes appropriate measures to limit the Company's and its customers' exposure to them. Liberty's concern is that the Commission also understand the risks that are inherent in the Atmos business model, and be comfortable with the limits on customer exposure that are negotiated into WKG's supply arrangements. Liberty's recommendation is that the Company prepare a series of brief reports to the Commission on this subject.

The first report should identify the principal risks, including counter-party risks and the risks of supplier failure. That same report should inform the Commission about the measures that Atmos is taking to limit its customers' exposure to those risks. Subsequent reports, perhaps at six-month intervals, should update the initial one, plus provide updates on principal indicators of the vitality of city-gate markets. Of particular interest will be the number of viable competitors, and their financial strength.

7. Affiliate Relations

a. Scope

This chapter of Liberty's report addresses the affiliate relations aspects of Western Kentucky Gas Company (WKG) gas procurement practices:

- Structure of Affiliated Companies.
  - Placement and Structure of the Gas Procurement Function within the Affiliated Companies.
- Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.
  - Non-Gas Transactions with Affiliated Companies.
- Accounting and Reporting Issues for Affiliate Transactions
  - Cost Allocation Manual (CAM)
  - Allocation of Employee Time and Overheads
  - Other Accounting Issues
- Affiliate Transactions Relative to KRS 278
- Other Issues of Note

b. Background

(1) Structure of Affiliated Companies and Placement of Gas Procurement Function

WKG is a division of the utility operations segment of Atmos Energy Corporation (Atmos), a Texas and Virginia corporation. The other utility divisions are Greeley Gas Co., United Cities Gas Co., Energas Co. and Atmos Energy Louisiana Gas Co. Acquisition of Mississippi Valley Gas Co. is expected to be completed during the 2002 fiscal year. The non-regulated segment is primarily composed of Atmos Energy Marketing, LLC (of which Woodward marketing, LLC is a wholly owned subsidiary), Atmos Pipeline and Storage, LLC, and Atmos Power Systems, Inc. The non-regulated companies are separate subsidiary entities under Atmos Energy Holdings, Inc.

Gas procurement for all of the utility divisions is the responsibility of the Gas Supply Planning Department (Gas Supply), which reports to the Vice President, Gas Supply. The function is part of another unit of the corporation, Atmos Shared Services Division. Shared Services provides multiple administrative and executive functions for the regulated and non-regulated segments of Atmos.

The shared services model, combined with the use of a gas asset management contract, allows a relatively small number of employees to provide for the gas procurement and load control for all of the utility divisions.

(2) Gas Supply, Transportation, and Storage Transactions with Affiliated Companies.

Gas Supply provides procurement for all five utility divisions of Atmos. WKG assigns all its pipeline and supplier contracts to Woodward Marketing, LLC under WKG's agency (asset management) agreement. Pipelines and suppliers invoice Woodward, and Woodward invoices WKG/Atmos. Woodward is an affiliated gas marketing company that was selected after the original contract holder claimed huge financial losses and asked to be released from the contract. Woodward had been the second place bidder and was willing to honor the terms of its original bid. WKG presented the selection to the Commission, and, in Case 99-447, the decision to award the contract to Woodward was found to be reasonable and in the public interest.

The Woodward contract reviewed in Case 99-447 expired in May, 2002. During the course of this project, Western was in the process of issuing an RFP and evaluating bids for a new agency agreement to run for a four-year term until 2006, coterminous with the extension of WKG's PBR.

(2a) Non-Gas Transactions with Affiliated Companies.

Atmos' structure, under which the five (5) LDCs and the shared services group are divisions of the company and not separate entities, means that there are almost no non-gas transactions with affiliated companies.

(3) Accounting and Reporting Issues for Affiliate Transactions

(3a) Cost Allocation Manual (KRS 278.2205)

Costs for centralized, shared functions, including accounting, human resources, gas supply, legal, rates and the Customer Service Support Center are fully allocated by Atmos. A Cost Allocation Manual (CAM) details how shared service units expenses are allocated to its regulated divisions and non-regulated affiliates and how utility division general expenses are allocated to regional or rate division levels. In addition to sections defining corporate structure, account coding structure, and a glossary, services provided by the shared service unit are described in the CAM, and the provider and users of the service are listed as well as the basis for allocation among the users. The basis for allocation varies with each service, and examples of the basis for allocation include sales revenue, number of meters, capital expenditures, gross direct property plant and equipment, number of customers, and number of employees.

(3b) Allocation of Employee Time and Overheads

Gas Supply executive time is allocated based upon an analysis of the time each of the analysts, or lower level positions, spends on matters for the various 5 utility business units, WKG being one of these business units. If a manager or executive spends time on a division or affiliate that has not been included in the analysis, it is possible to do exception reporting so the appropriate cost center is charged.

(3c) Other Accounting Issues

Invoices from Woodward Marketing, which holds the current asset management contract for WKG, can contain commodity, transportation and storage components. The verification and approval process is thorough, and each invoice is reviewed and approved for the following: logged to gas analyst, price checked, volumes/quantity checked, director approval, vice president approval, and rate division code. The distribution of charges to the appropriate accounts is done by a senior accountant, who is also responsible for ensuring the charges are properly reflected in the general ledger.

There are no subaccounts within the chart of accounts to reflect affiliate transactions. The accounting department treats Woodward Marketing (a wholly-owned affiliate) as just another vendor. At this time, Atmos is not required by any jurisdiction to report affiliate transactions.

(4) Affiliate Transactions Relative to KRS 278

In accordance with KRS 278.2213(12) - which requires that a utility notify customers of competing suppliers of a nonregulated service - WKG provides a list to transportation customers that includes alternative gas suppliers along with the name of its gas marketing affiliate.

The selection of Woodward Marketing, an affiliate, as the provider of asset management services for WKG, was the result of an open bid process. The award of the contract, which expired in May, 2002, resulted in a determination by the Commission in Case 99-447 that the selection of Woodward, the second place bidder, after the original contractor was released from the contract, was reasonable and in the public interest.

c. Conclusions

(1) Gas procurement is provided by the Gas Supply Department in Dallas, Texas, under a shared services unit model. This model prevents duplication of services and overheads when providing gas procurement for multiple distribution utilities.

The shared services model, combined with an asset management contract, allows a relatively small organization to provide gas procurement for WKG and its sister utilities.

(2) All the utilities owned by Atmos Energy Corporation, and the shared services unit, are divisions of Atmos, not affiliated companies.

Atmos' corporate structure is unique among the five (5) utilities studied under this audit, where the holding company model is predominant. Even though the shared services unit is a division of the single company, rather than a separate entity, the issues surrounding allocation of shared costs among regulated and non-regulated entities are similar to those entities using a holding company structure.

(3) WKG's asset management contract with affiliate Woodward Marketing that expired in May, 2002, met the arm's length standard of business dealings, per Case 1999-447.

Award to an affiliate of the contract for asset management services occurred after a competitive bid process. After WKG detailed the evaluation/selection process to the Commission, the Commission's review of the process resulted in the decision that selection of Woodward was reasonable and in the public interest.

(4) Invoices from Woodward Marketing provide sufficient detail and are handled appropriately within WKG.

Atmos' invoice verification and approval process is thorough. Multiple individuals review the invoice, and appropriate backup for volumes and pricing is attached to the invoice, as is the detail for distribution to the general ledger, prior to its submission to accounts payable.

(5) WKG uses an appropriate process for allocating shared-service costs among the utilities, as detailed in its Cost Allocation Manual.

The Cost Allocation Manual identifies services provided to regulated divisions and non-regulated affiliates, and defines the basis of allocation of costs for each service. The basis for allocation varies with each service, and examples of the basis for allocation include sales revenue, number of meters, capital expenditures, gross direct property plant and equipment, number of customers, and number of employees.

(6) The Atmos chart of accounts does not contain affiliate subaccounts.

Atmos states it is not required to report affiliate transactions to any jurisdictional authority. If asked to report such information, the company would search for transactions by vendor name. The ability to identify affiliate transactions in this manner meets the FERC requirements related to identifying such transactions.

(7) In accordance with the requirements of KRS 278.2213, when requested, WKG provides to its transportation customers a listing that includes names of alternative gas suppliers when the name of its gas marketing affiliate is included.

The referenced statute states that if a utility receives a request for a recommendation from a customer seeking a specific service which is offered by the utility or its affiliate, competing suppliers must be provided if the utility names itself or its affiliate. WKG meets this requirement by providing an appropriate listing of suppliers.

d. Recommendations

None