IV. Load Forecasting and Supply Planning

A. Introduction

1. Objectives

The RFP objectives related to planning sought a review of:

- The reasonableness of methods for forecasting peak day and annual demand
- The consistency of asset acquisition with ensuring supply adequacy and reliability without oversupply at the least possible cost
- The reasonableness of the gas supply portfolio structure to meet forecasted peak day and annual demand
- The flexibility of winter demand portfolio planning in balancing ability to supply in warmer months without risking significant oversupply
- The sufficiency of internal controls to ensure compliance with operational supply plans while preventing the use of ratepayer storage and supply assets for non-ratepayer benefit
- How the Utilities consider reliability, flexibility, supplier diversity, and price when determining gas-supply portfolio mixture, comparing the use of city gate contracts versus supply obtained from retaining field zone and pipeline transportation to the city gate.

This chapter addresses all of these objectives except for the final one, which Chapter V addresses. Liberty addressed these objectives by examining:

- Peak-day forecasting approaches, models, methods, results, and the use of forecasts for portfolio planning purposes.
- The basis for structuring the elements of the gas-supply portfolio, and the portfolio's optimization of reliability and cost considerations.

Liberty applied the following criteria in performing its examination of planning-related issues:

- Forecasting should be routinely performed, updated regularly, and used to develop and assess the continuing viability of portfolio design and implementation
- Weather-data handling, modeling, and analysis methods should be comparable to industry norms
- Assumptions, variables, and probabilities in capacity planning should be consistent with observable supply obligations, and should consider all factors that can affect consumption
- There should be regular and comprehensive evaluations of forecasting effectiveness, of the adequacy of the portfolio, and of operational plans and actions to use that portfolio in relation to reliably and economically meeting annual and peak requirements
- Over time, there should be a strong correlation between the capacity portfolio and the load duration curve
- Gas portfolio and corporate plans should be consistent and complementary.

2. Background

a. General

Large-volume customers have had access to contract gas-transportation service since the mid-1980s. The ICC approved applicable tariff riders (in 1990 for Peoples Gas and 1991 for North Shore) that made transportation service available to all but small residential customers. Peoples Gas introduced in 1997 a pilot program targeted to small volume customers. All customers in both Utilities' service territories have been able since 2002 to choose whether to use the utility for gas supply, or to choose a third-party supplier to deliver the gas through the utility's distribution system under a transportation tariff.[123] The Utilities have a broadly diversified customer base. Peoples Gas has an urban mix of residential, commercial, and industrial customers, while North Shore has a suburban mix of residential, commercial, and industrial customers. North Shore's customer numbers grew modestly, but those of Peoples Gas declined during the audit period. The tables below show the numbers and types of customers served by each of the Utilities during the audit period.

Peoples Gas Numbers of Customers in Each Service Class at Fiscal Year End[124]

	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006
Retail								
Company Use			4					
S.C. 1	734,400	738,078	749,438	736,904	712,275	705,148	709,226	699,822
S.C. 2	67,449	73,125	67,680	68,315	67,343	68,410	68,425	65,704
S.C. 3	2	2	11	13	23	12	15	9
S.C. 4				1			2	
S.C. 6	41	41	39	42	38	41	57	40
S.C. 8	4	4	5	5	5	4	4	4
Retail Total	801,896	811,250	817,177	805,280	779,684	773,615	777,729	765,579
Transportation								
Company Use			56	59	60	60	52	50
S.C. 1				1,632	4,342	3,507	7,096	21,031
S.C. 2	20,423	14,659	19,660	17,345	16,708	15,498	14,700	16,552
S.C. 3	173	171	171	164	160	158	156	153
S.C. 4	42	42	36	31	29	29	27	27
S.C. 5	3	3						
S.C. 6	1	2	3	3	3	3	3	3
S.C. 7			5	7	5	4	3	3
Transportation Total	20,642	14,877	19,931	19,241	21,307	19,259	22,037	37,819
Grand Total	822,538	826,127	837,108	824,521	800,991	792,874	799,766	803,398

[123] Response to Data Request #34.
[124] Response to Data Request #36. S.C.1 (Small Residential Service) is residential service through a single meter for one or two dwelling units. S.C.2 (General Service) is general service for residential (multi-unit), commercial and industrial customers. Peoples Gas' S.C.3 (Large Volume Service) is service for customers with more than 41,000 therms per month. Peoples Gas' S.C.4 and North Shore's S.C.3 is service with a demand charge. Peoples Gas' S.C.6 and North Shore's S.C.5 are both Standby Services offered to their customers who may need to supplement their other sources of energy. Peoples Gas' S.C.5 (Electric Generation, Transportation, and Storage Service) was eliminated in FY1997 and replaced in FY2000 with a negotiated rate service available to certain power generators. North Shore's counterpart is S.C. 6. Peoples Gas' S.C.7 and North Shore's S.C.4 are both Contract Services available to those large volume customers that are able to bypass the utility's gas distribution system. Cities or municipalities purchase Peoples Gas' S.C.8 (Compressed Natural Gas Service) to run their natural-gas fueled transportation vehicles; other customers are eligible for this service classification.

North Shore Numbers of Customers in Each Service Class at Fiscal Year End[125]

	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006
Retail								
Company Use	-	-	-	-	-	-	-	-
S.C. 1	134,235	136,614	136,560	136,639	137,149	137,375	138,870	138,827
S.C. 2	10,344	10,705	10,563	10,696	10,572	10,631	10,708	10,470
S.C. 3			1			1	1	
S.C. 5	87	87	93	98	102	106	107	85
Retail Total	144,666	147,406	147,217	147,433	147,823	148,113	149,686	149,382
Transportation								
Company Use			19	19	19	19	19	20
S.C. 1				1,372	1,188	2,270	2,529	3,491
S.C. 2	1,884	1,895	1,851	1,963	2,042	2,101	2,146	2,443
S.C. 3	3	5	3	2	2	3	3	3
S.C. 4			3	3	3	3	3	3
S.C. 5								
Transportation Total	1,887	1,900	1,876	3,359	3,254	4,396	4,700	5,960
Grand Total	146,553	149,306	149,093	150,792	151,077	152,509	154,386	155,342

Consumption by Peoples Gas' customers declined over the period while North Shore's customers consumed approximately the same volumes of gas. The tables below show throughput for each of the Utilities by customer class for each year of the audit period.

Peoples Gas Annual Throughput by Service Class[126]
(MMDth)

	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006
Retail								
Company Use	-	-	-	-	-	-	-	-
S.C. 1	79	78	85	75	85	77	73	68
S.C. 2	37	40	40	36	41	39	36	34
S.C. 3	0	0	0	0	1	1	1	1
S.C. 4	0	-	0	0	(0)	0	0	0
S.C. 6	0	0	0	0	(0)	0	0	(0)
S.C. 8	0	0	0	0	0	0	0	0
Retail Total	116	118	125	111	127	117	110	103
Transportation								
Company Use	-	-	1	1	1	1	1	1
S.C. 1	-	-	-	0	1	1	1	2
S.C. 2	53	48	52	46	49	44	43	40
S.C. 3	16	17	17	15	15	14	14	13
S.C. 4	17	17	14	12	11	11	11	11
S.C. 5	1	1	(1)	-	-	-	-	-
S.C. 6	0	0	0	0	0	0	0	0
S.C. 7	6	5	6	6	5	5	4	4
Transportation Total	94	87	88	80	82	76	73	70
Grand Total	210	205	213	191	210	192	183	173

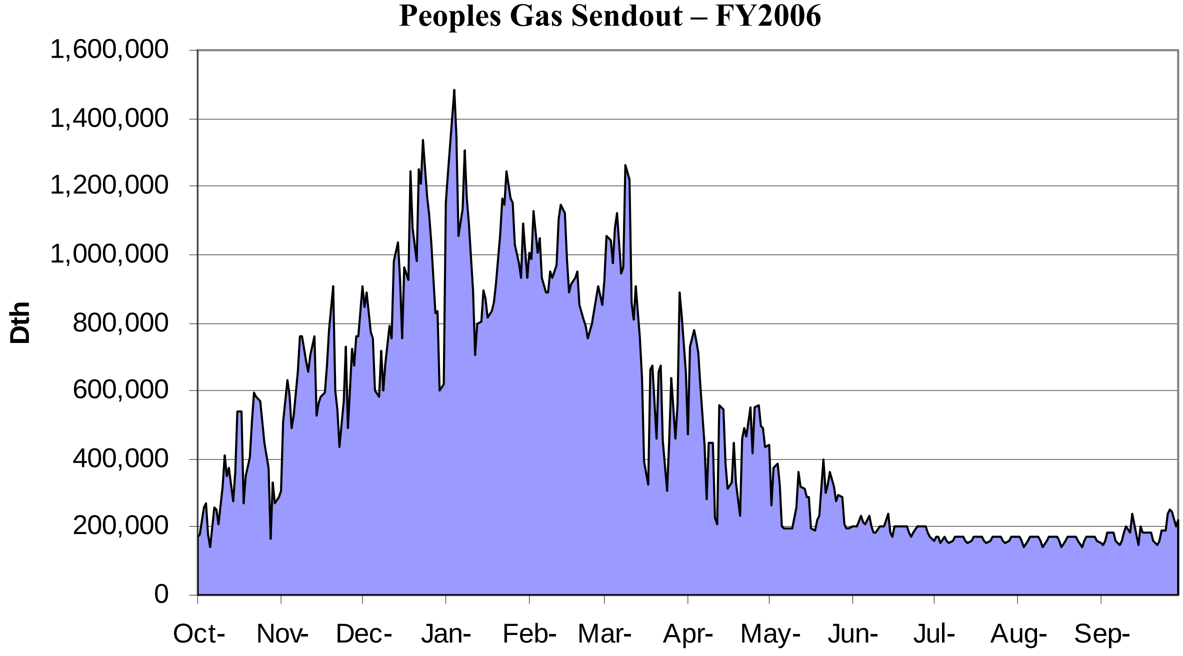
[125] Response to Data Request #36.
[126] Response to Data Request #36.

North Shore Annual Throughput by Service Class[127]
(MMDth)

	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006
Retail								
Company Use	-	-	-	-	-	-	-	-
S.C. 1	19	19	21	18	22	19	19	18
S.C. 2	4	4	5	4	5	5	5	4
S.C. 3	-	-	0	0	0	0	0	(0)
S.C. 5	0	0	0	0	0	0	0	0
Retail Total	23	23	26	23	27	24	23	22
Transportation								
Company Use	-	-	0	0	0	0	0	0
S.C. 1	-	-	-	0	0	0	0	0
S.C. 2	9	9	8	8	8	8	8	8
S.C. 3	1	1	1	1	1	2	2	2
S.C. 4	2	2	2	2	2	3	3	2
S.C. 5	0	-	-	-	-	-	-	-
Transportation Total	12	12	10	11	12	13	13	13
Grand Total	35	35	36	33	38	37	36	35

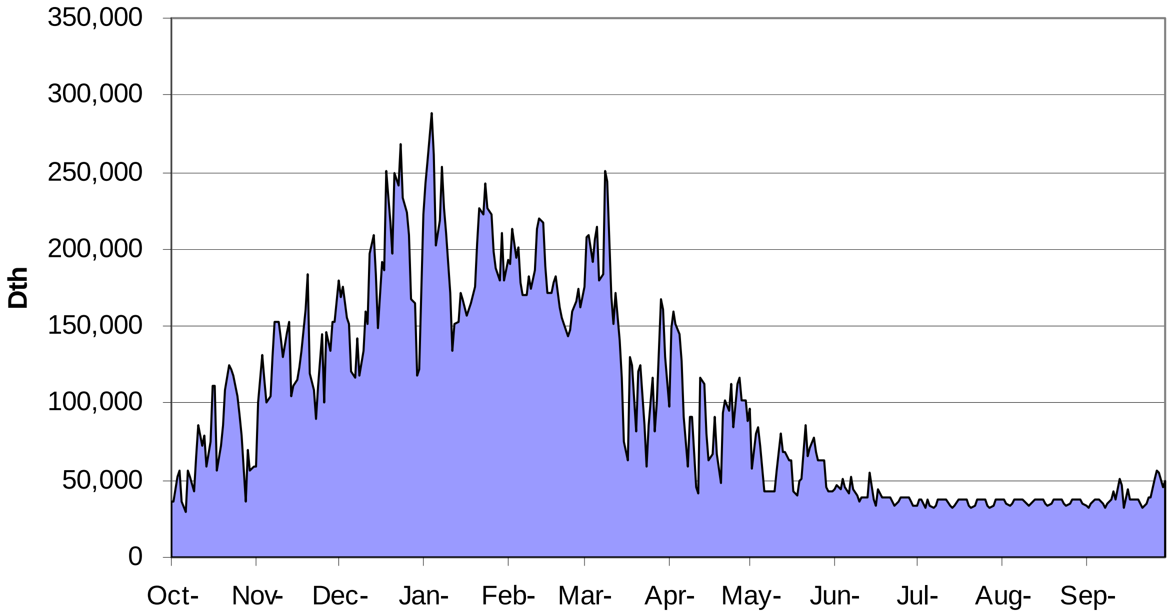
The Utilities' loads are highly weather-sensitive. The charts below show the FY2006 sendout for each of the two Utilities.[128]

Peoples Gas Sendout – FY2006



[127] Response to Data Request #36.
[128] Response to Data Request #166.

North Shore Sendout – FY2006



The Utilities' delivery capacity comes from a combination of company-owned gas transportation, storage and peak-shaving facilities, and contracts for transportation and storage services with interstate pipeline companies. Various producing and marketing companies provide commodity gas supplies.

Seven interstate pipelines serve Peoples Gas. Natural Gas Pipeline Company of America (NGPL) serves Peoples Gas directly, via two connections to its city gates and two interconnections at its Manlove Storage Field. NGPL also serves Peoples Gas indirectly, through Peoples Gas' Oakton Street Gate Station. Peoples Gas connects to six others through their interconnections with the Mahomet Pipeline.

The Mahomet Pipeline is a high-pressure pipeline owned by Peoples Gas that connects Manlove Field to its gas distribution system with two cross-connected, parallel, high-pressure pipelines. Manlove Field is its on-system storage facility in central Illinois. The Mahomet Pipeline, with a capacity of 2.325 Bcf/day, interconnects Peoples Gas with the seven interstate pipelines.[129]

The seven pipelines with which Peoples Gas interconnects through Mahomet are NGPL, Northern Border Pipeline Company (three connections), ANR Pipeline Company (two connections), Guardian Pipeline, Alliance Pipeline, the Midwestern Gas Transmission Company system, and Trunkline Gas Company.[130] The Utilities access the Tennessee Gas Pipeline system through Midwestern, and Panhandle Eastern through Trunkline.

Two interstate pipelines, NGPL and ANR, serve North Shore. One of its connections to ANR is through Northern Illinois Gas Company's (NIGas') Busse Road Station. North Shore has a peaking facility at its Peterson Road location, which is adjacent to NGPL's Grayslake Station.[131] Unlike Peoples Gas, North Shore does not have any on-system storage capacity. Rather, it leases

[129] Response to Data Request #38.
[130] Response to Data Request # 38, Attachment 3.
[131] Response to Data Request # 38, Attachment 4.

1.78 Bcf from its sister utility's on-system capability at Manlove Field while mostly relying on ANR (6.25 Bcf) and NGPL (2.25 Bcf) for its current total storage capacity of 10.3 Bcf.[132]

Until 1981, the Utilities were affiliates of Natural Gas Pipeline Company of America (NGPL).[133] PEC started NGPL, and designed its facilities to serve the two Utilities. A major supply-planning objective since separation from NGPL has been to lessen their dependence on their former affiliate.[134]

The diagram below shows the structure of the facilities in the Chicago marketplace and the interconnections available to Peoples Gas and North Shore.

[132] Response to Data Request #38.
[133] The Utilities and NGPL were affiliated until 1981, at which time PEC reorganized such that PEC remained the holding company for Peoples Gas and North Shore and MidCon was formed as a holding company that owned NGPL and other non-utility companies previously owned by PEC. MidCon Corporation was eventually acquired by Kinder Morgan's subsidiary KN Energy Inc. and subsequently reorganized under Kinder Morgan Energy Partners (KMP).
[134] Interview #16, February 2, 2007, Interview #26, March 15, 2007, and Interview #27, March 16, 2007. In comments on Liberty's Draft Report, the Utilities reported that, during the audit period, NGPL was the only pipeline that could deliver to either Utility without using Peoples Gas' Mahomet Pipeline. Therefore, at a minimum, the Utilities needed to contract for NGPL peak-day services to the extent that their peak-day supply requirements exceeded the capacity of the Mahomet Pipeline. The capacity of the Mahomet Pipeline is reported as 2.325 Bcf/day (response to Data Request #38), which is about 2.378 MMDth. Other materials supplied to Liberty (see, *e.g.*, the response to Data Request #38) report that North Shore, at least, is also connected to ANR.

Major Midwest Pipelines[135]

Peoples Gas and North Shore operate in the Chicago gas marketplace; however, their service territories do not join at any point, and there are no physical interconnections between them. The unaffiliated Northern Illinois Gas Company operates the service territory that is between the Utilities. PEC treats Peoples Gas and North Shore as two distinct utility systems for planning purposes.[136]

[135] Response to Data Request #166, p.17.
[136] Response to Data Request #38, Interview #14-15, January 31, 2007 and Interview #16, February 2, 2007.

The table below shows the Utilities' 2006 peak-day supply resources.

2006 Peak-Day Supply Resources

(Volumes Dth)	PGL	NSG
Term Supply	320,000	58,000
Leased Storage	583,000	233,000*
Manlove Underground	694,000	0
Manlove LNG	300,000	0
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Bell Road Propane	60,000	0
LP (Liquid Propane)	0	40,000
Transportation Customer Gas	258,000	54,000
Total	**2,345,000**	**437,000**

* 63,000 Dth of this is through a contract with Peoples Gas for capacity in Manlove Field.

b. Load Forecasting

Liberty evaluated the Utilities' load forecasting function by exploring forecasting and planning processes, and how their results affected reliability and price of supply and operations. Liberty also examined how the Utilities identified and addressed changing needs and supply and market conditions during the audit period. This examination addressed responses to known and foreseeable changes and considered how effective the Utilities were in developing and exercising the capability to respond flexibly and timely to unknown and unforeseeable potential changes, which have characterized the natural gas industry over the last several years.

Liberty assessed the Utilities' analysis of historical weather and weather patterns that form a core element in determining the main elements of natural gas supply forecasts for the design day and for the normal annual and design winter forecasts. This included a review of other influences on requirements for supply such as wind, trends in use per customer, and conversion of sales to transportation. How the Utilities performed annual, peak-day, and other daily forecasts comprised a major focus of Liberty's assessment.

Liberty examined the integration of the various elements of forecasts into load duration curves. Factors considered included:

- Normal weather/design weather
- Integration of usage trends among the various customer classes
- Changes over time.

Liberty also reviewed efforts to compare forecasts with actual requirements for use in: (a) improving the accuracy of forecasts, and (b) identifying influences on requirements that the Utilities may not have incorporated into earlier forecasts.

c. Supply Planning

To assess supply-planning activities, Liberty evaluated the Utilities' practices against industry standards and common practices in gas supply planning and capacity acquisition, strategy development, and execution in dynamic market conditions. Supply planning activities of an LDC include assessment of pipeline capacity, storage, and peaking to meet forecasted load for peak day and winter months. Moreover, planners must be aware of both changing market dynamics in their service areas to address developing issues as well as taking initiatives on new capacity choices and changing demand profiles of their customer bases.

Successful supply planning requires the Utilities to rapidly update and be able to run varying future (sometimes very short-range) scenarios quickly and accurately. Models with this capability serve as important tools for forecasting, which can be very much dependent on changes in the weather, supplier disruptions, or short-term fuel market conditions.

Liberty's evaluation of supply planning involved three key practice areas. The first, supply portfolio analysis, is the search for and acquisition of a resource mix of firm transportation (FT), storage, and peaking capacity that minimizes costs while allowing the provision of reliable service under various demand scenarios.

The second is how the Utilities modified their supply portfolio in response to changing market conditions that are particularly crucial for an LDC facing the uncertainty of transportation demand and of customer switching between transportation and sales services. Observed customer migration trends between transportation and sales services, historical practices in capacity planning, and limitations on available capacity options may affect supply portfolio and capacity planning.

The third key practice area involves the examination of capacity alternatives**.** An LDC must search, identify, and adjust contract terms according to changing market conditions, in order to try to avoid commitments that may place the company at a disadvantage by better matching its capacity to the forecasted load, and by bargaining and seeking resource alternatives.

B. Findings

The Utilities' forecasting activities, conducted primarily in connection with its annual profit planning, have two aspects:

- Sales forecasting, conducted primarily through econometric analysis of billing records for Rate 1 and Rate 2 customers, and review of recent customer history for Rates 3 through 8, focused on billing and revenues
- Sendout forecasting, conducted with a suite of regression and optimization computer models, and focused on dispatching and gas costs.

This section addresses the first of those two aspects. The Supply Planning section addresses the second.

The Utilities used regression analysis, which consists of comparative statistical analysis of related variables (such as temperature and sendout) for both aspects. Sales forecasting used regression of weather against customer metering and billing data, while sendout forecasting used regression of weather against sendout. The two different sets of analyses were used for different purposes, but were checked against each other periodically.[137]

1. Load Forecasting

a. Annual Throughput

The Utilities typically began their annual load forecasting processes in early April and concluded them in late August to coincide with the next fiscal year's Annual Profit Plan. As soon as the Utilities would obtain actual March data, they prepared the Design Peak Day (DPD) model in about one week. About the same time, the Utilities would begin the Long-Term Sales (LTS) forecasting process to estimate its two key components. These components are: (1) the Firm General Demand (FGD), which is primarily residential rate classes, and (2) Large Volume Demand (LVD), which consists of the commercial and industrial rate classes.

The Utilities would then forecast customer demand, which consists of total retail sales volumes plus total transportation volumes. There are eight rate classes of customers. The Utilities classified Rate 1 and 2 customers as FGD and the others as LVD. Due to the marked difference in usage patterns and volumes between these two groups, the Utilities used two forecast methods. They used regression analysis for Rates 1 and 2. This top-down approach measures an entire customer segment's sensitivity to certain explanatory variables (*e.g.*, weather, price, and estimated efficiency improvements). They used a bottom-up approach for Rates 3 through 8 based on historical results and specific customer analyses by the Sales, Rates, and Utility Accounting and Control Departments. The two-pronged approach resulted in two separate forecasts to arrive at the forecast of total demand—a forecast of FGD and a forecast of LVD.

The forecast process for FGD used a multi-component approach. It first divided demand for Rate 1 and Rate 2, and then divided each into demand by heating and non-heating customers. Finally, the process attributed demand to number of customers and usage per customer. This disaggregation of FGD provided the following eight components, forecasted independently on a monthly basis for both Utilities:

- Usage per non-heating Rate 1 customer
- Number of non-heating Rate 1 customers
- Usage per heating Rate 1 customer
- Number of heating Rate 1 customers
- Usage per non-heating Rate 2 customer (North Shore's customers were grouped with large volume customers due to this segment's usage per customer volatility from 1997-1999)
- Number of non-heating Rate 2 customers (North Shore's customers were grouped with large volume customers due to this segment's usage per customer volatility from 1997-1999)
- Usage per heating Rate 2 customer
- Number of heating Rate 2 customers.

The Utilities divided FGD into these components because various economic, demographic, and weather factors affect each component differently. By examining individual components and

[137] Response to Data Request #22.

relating them to these factors, the Utilities have been able to gain a greater understanding of how these factors affect FGD.

The forecasting process performed a multiple regression analysis on each of the eight components. This procedure statistically related each component to factors expected to affect that component. The equations generally used econometric methods to relate specific components of FGD to factors such as natural gas prices and weather. Finally, the model estimation process yielded a forecasting equation for each component of FGD.[138]

After development of the forecasting equations for each component, the Utilities would gather expected future values for each factor used in the model: gas price, weather, use efficiency improvements, etc. Inputting these values into the forecasting equations yielded predicted monthly values for each of the eight components. The process determined total monthly demand by adding the eight components, and annual demand by summing the 12 monthly demand numbers.

For Rates 3 through 8, the forecast process would start with the annual usage from the most recent 12-month period. The Sales, Rates, and Utility Accounting and Control Departments then developed expected changes for each customer based, in part, on interviews with customer representatives. The process would then add to or subtract from the recent, actual data to yield a forecast for the coming period.

After completing the FGD and LVD forecasts, the Utilities used a separate analysis to divide the total volumes and customers into the retail and transportation segments. For FGD, the approach was generally to use the same forecasting method for sales customers only, and then subtract those numbers from the totals to yield the transportation numbers. The Utilities can identify sales customers through billing records, which is the source of the data for the regression analyses. For LVD customers, all of the transportation customers sign annual agreements that specify the levels of service that they require. Those annual agreements served as a primary data source for the Sales and Rates Department's estimates of each customer's consumption for the coming year. The Utilities estimated sales-service customers from the prior year's usage, unless the Department knew of a reason to change the expectation for a given customer.

b. Design Peak Day

The Utilities have defined Design Peak Day (DPD) as the sendout expected on a January weekday with an average temperature of minus 20 degrees Fahrenheit. The Utilities' policy has required that there be no more than a 2 to 2½ percent chance that the actual sendout experienced on such a day could exceed the DPD estimate.

The Utilities defined the weather criterion as 85 degree-days. That criterion calculates degree-days in a manner that is different from the Heating Degree Day (HDD) data collected and published by the National Oceanic and Atmospheric Administration (NOAA).[139] Rather than the

[138] Response to Data Request #22 Attachment A.
[139] A heating degree-day is a measure relating temperature to the demand for heating fuel. Heating degree-days for a particular day is determined by taking the arithmetic average of the day's high and low temperatures. If the resulting number is above 65, there are no heating degree-days for that day. If the number is less than 65, then the resulting

average of the high and low temperatures for a calendar day, the Utilities' criterion represented the average of the 24 hourly temperatures recorded between the beginning and the end of the gas day. (The gas day is the 24 hours between 9:00 a.m. on one calendar day and 9:00 a.m. on the next calendar day.) Using this approach, the Utilities were better able to relate the temperature data that they use for the design-day calculation to sendout data as measured at various points on their distribution systems, and to delivered quantity information measured at the Utilities' gate stations.

The Utilities report that the design-day weather criterion has occurred twice (January 9/10, 1982 and January 19/20, 1985) in the 48 years for which consistent temperature data is available. The 24-hour average temperature was also below minus 19 degrees Fahrenheit (but not quite minus 20) on January 15/16, 1982.

For each fiscal year from FY2001 through 2006, the Utilities used the same process to estimate the DPD. That process was as follows:[140]

- Select the Utilities' actual sendout, temperature, and degree-day information for all weekdays, in the months of December through February for the past five years
- Sort the daily data by temperature, putting the coldest days first
- For the group of all weekdays averaging 35 degrees F or colder
    - Count the number of days in the group
    - Perform an Ordinary Least Squares linear regression of sendout against degree days to produce
        - A daily base load
        - Use per degree-day
        - "Goodness-of-fit" measures
        - Standard error of the regression
    - Compute the required confidence level estimate of the DPD.
- For future years, *i.e.*, years beyond the first year of the forecast horizon, adjust the resulting DPD estimate for econometric-based expected load change between January of the first forecast year and the January in which the DPD could occur. These expected load changes could be positive or negative.

Once the Utilities derived the daily base-load and use-per-degree-day estimates, they added to the base-load two increments. First is heating load (calculated as the product of 85 degree-days times the sendout per degree-day derived from the regression model). Second is two standard deviations from the result produced by the regression model. The first increment adds in the calculated heating load; the second increases to 97.5 to 98 percent the probability that the actual system sendout under the design-day conditions will not exceed the resulting estimate.

Prior to FY2001, the Utilities developed the DPD as an historical average of available data, using the results of the same January sendout regressions used for the long-range daily gas sendout requirements forecast.[141] The Utilities began using the four-step methodology outlined above in that year. Since the Utilities typically forecast more than one year into the future, Step 4 adjusts

number is subtracted 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.

[140] The process is described in the Response to Data Request #22, Attachment A, pp. 1-2.

[141] Response to Data Request #63, and Interview #25, March 16, 2007.

the first-year DPD estimate for future years (past the first year) using econometric-based expected load changes developed in the Long-Term Sales Forecasting Methodology. The table below shows the results of the DPD calculations for the first year of the forecast horizon for the last three fiscal years of the audit period.[142]

Utilities' Design Peak-Day for FY2004-FY2006 (Dth/day)

	PGL				NSG			
Fiscal Year	**Baseload**	**Heating**	**2 Std. Dev.**	**Total**	**Baseload**	**Heating**	**2 Std. Dev.**	**Total**
2004	306,331	1,888,657	155,668	2,350,655	31,001	358,753	20,026	409,779
2005	298,421	1,876,676	166,711	2,341,808	28,327	365,345	20,359	414,030
2006	225,661	1,916,785	138,243	2,280,689	23,910	377,065	23,634	424,610

The Utilities have validated the reasonableness of their DPD estimates by comparing them with the sendouts on one of the coldest recorded days (*e.g.*, Tuesday, January 18, 1994 required sendout of 2,327,076 Dth for Peoples Gas at minus 14 degrees Fahrenheit), and asking what the additional sendout would have been had the temperature dropped to minus 20 degrees Fahrenheit (*i.e.*, adding 135,828 Dth that is obtained by multiplying the FY2005 sendout-per-degree-day estimate by an additional six degree-days). Because that hypothetical Peoples Gas sendout requirement (2,462,904 Dth) is sufficiently above Peoples Gas' FY2005 estimate of 2,341,808 Dth, the Utilities have found their estimate reasonable.[143]

The Utilities performed a reasonableness check using January 5, 1999, (the day after the coldest day in January 1999) to show the effects of prior-day weather. The Utilities selected January 5, 1999, because they believed that a minus 20 degree-day would more likely follow a minus 5 degree-day than a plus 7.2 degree day.[144] This illustrates why the customer demand on January 4 at minus five degrees is relatively low, because January 3 (averaging plus 7.2 degrees) was over 12 degrees warmer. Similarly, January 28, 2004, was over six degrees warmer than January 29. The table below uses January 5, 1999 as the basis for an additional DPD reasonableness check.

Reasonableness Check on DPD Estimates (Dth/day)

	PGL			NSG		
Fiscal Year	**Utilities Estimate**	**Alternative Check**	**Difference**	**Utilities Estimate**	**Alternative Check**	**Difference**
2004	2,350,655	2,370,723	-20,068	409,779	403,762	6,017
2005	2,341,808	2,366,988	-25,180	414,030	405,818	8,212
2006	2,280,689	2,379,493	-98,804	424,610	409,472	15,138

c. Weather Data

A significant portion of the load for local distribution companies, especially the load related to residential customer classes, has a strong correlation with weather. The use of appropriate

[142] Response to Data Request #27.
[143] Response to Data Request #27.
[144] Response to Data Request #27.

weather data is crucial in determining the forecasted level of demand for different weather scenarios. LDCs typically assess base forecasts on what they call *normal weather*. That term is defined by an average of historically observed heating degree-days (HDDs) over a number of years, as recorded by an independent authority such as the National Oceanic and Atmospheric Administration (NOAA).

LDCs factor weather into their forecasts in many ways. Coldest days and HDDs comprise the most widely used weather elements by forecasters. The analysis and use of weather data is a crucial component of an LDC's natural gas load forecasting. It is important to the determination of design peak-day and of annual sendout.

The Utilities have used weather data from the O'Hare Airport weather station for load forecasting and supply planning purposes.[145] The metropolitan Chicago area has two other airports: Midway Airport and Palwaukee Municipal Airport (also known as the Chicago Executive Airport). NOAA did not report weather data on a regular basis for Midway before 1979. Palwaukee has never had an identification with NOAA as a weather station. Therefore, the Utilities have relied on O'Hare Airport for weather data for forecasting and planning before and throughout the audit period.[146]

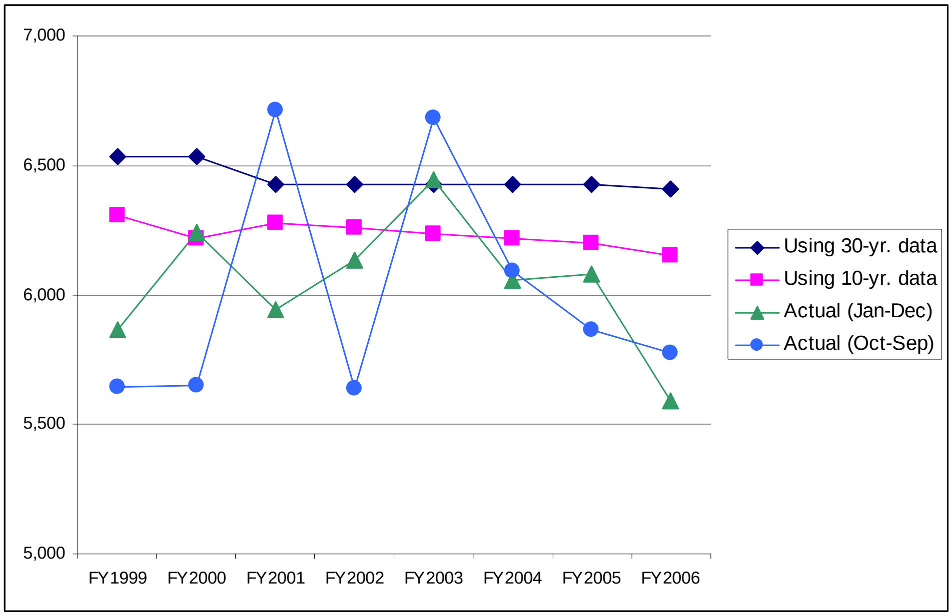
The Utilities prepared annual forecasts of gas requirements and capacity entitlements based on normal weather. Over the audit period, the Utilities calculated normal weather as the average of annual HDD over a 30-year period. They then used the 30-year average for the succeeding five years, replicating the NOAA pattern of updating weather records every ten years. Therefore, for the period FY1996 through FY2000, the Utilities calculated and used 6,536 HDDs. They used 6,427 HDDs between FY2001 and FY2005; they used 6,408 HDDs for FY2006.[147]

For FY2007, the Utilities adopted a new approach to the length of period for weather data. They reduced the averaging period to 10 years, resulting in a new normal-weather year of 6,175 HDDs. The Utilities report that this is more in line with the current industry practices. Using 10-year data and applying it to the audit period, Liberty obtained annual HDD comparisons as illustrated in the table that follows and accompanying chart. Actual HDD data are shown for the same periods for comparison, both on a calendar-year basis (January through December) and on a fiscal-year basis (October through September). The chart and table plot the 30-year, 10-year, and actual data.

[145] Although the Utilities collect the wind data, they do not use them in their long-term load forecasting. In response to Data Request #22 and in comments on Liberty's Draft Report, however, the Utilities pointed out that they use at least two forecasting models that incorporate wind in the five- to seven-day (short-term) forecast.
[146] Response to Data Request #24.
[147] Response to Data Request #25.

Annual HDDs: 30-year vs. 10-year with Actual HDDs

	Using 30-yr. data	Using 10-yr. data	Actual (Jan-Dec)	Actual (Oct-Sep)
FY1999	6,536	6,309	5,866	5,646
FY2000	6,536	6,220	6,241	5,650
FY2001	6,427	6,275	5,943	6,712
FY2002	6,427	6,260	6,133	5,639
FY2003	6,427	6,236	6,443	6,684
FY2004	6,427	6,215	6,059	6,091
FY2005	6,427	6,199	6,083	5,864
FY2006	6,408	6,154	5,589	5,775



The Utilities' "Extreme Year" is 7,226 HDD, which is the actual HDD for fiscal 1982 (October 1981 through September 1982).[148] Fiscal 1984 had 7,235 HDD. Two fiscal years of the last 48 have thus experienced 7,226 HDD or higher. The Utilities' "Warm Year" for portfolio planning is fiscal 1998 (October 1997 through September 1998), which experienced 5,564 HDD.[149] The Utilities have used different colder-than-normal and warmer-than-normal design criteria in their monthly supply-planning exercises. They have tested each month's plan against the coldest and warmest weather ever experienced for that month.

d. Forecast Results

The Utilities made daily comparisons of their actual sendout to the long-range forecast. They saved the resulting Daily Sendout Forecast files on the Utilities' Intranet for future reference when developing the next long-range forecast.

[148] Response to Data Request #78.
[149] Response to Data Request #78.

The Utilities have done some work in evaluating changes in customer usage, and in understanding various reasons for changes in load, among them the load loss at Peoples Gas and the modest growth at North Shore. Two tables below show the results of the Utilities' research into factors that contributed to these trends through the audit period.[150]

Peoples Gas' analysis attributed the largest load loss to increasing gas prices (13.8 Bcf), the migration of large volume customers to alternative supply sources (*e.g.*, heating oil and/or plant closures in Chicago (11.6 Bcf), efficiency gains (9.3 Bcf), and other factors, which accounted for a total loss load of 36.5 Bcf from FY1999 to FY2006.

Peoples Gas Demand Attribution Analysis during the Audit Period

Peoples Gas Demand Attribution Analysis									
	(Volumes in Bcf)								
	1999	2000	2001	2002	2003	2004	2005	2006	Aggregate Change
Actual	209.9	204.9	213.2	191.1	209.8	192.3	183.2	173.4	
Forecast	212.3	206.7	214.9	189.0	208.7	190.2	184.8	175.6	
Error	-2.4	-1.8	-1.6	2.2	1.1	2.1	-1.7	-2.3	
% Error	-1%	-1%	-1%	1%	1%	1%	-1%	-1%	
UPC Forecast Error	-2.7	-1.8	-1.6	2.4	1.0	2.0	-1.9	-2.3	
Customer Forecast Error	0.3	0.0	-0.1	-0.3	0.1	0.1	0.2	0.0	
Change in Actual Demand from Prior Year		-5.0	8.4	-22.1	18.7	-17.5	-9.2	-9.8	**-36.5**
Change due to:									
Weather		-0.8	22.5	-21.5	20.1	-12.0	-2.8	-2.3	3.3
Base Load Shift		0.0	-1.7	-1.6	0.0	0.0	0.0	0.0	-3.3
Price		-1.3	-7.8	2.5	1.3	-4.1	-1.5	-2.8	**-13.8**
Efficiency Improvements		-2.0	-2.1	-1.5	-1.0	-0.9	-0.9	-0.8	**-9.3**
Large Volume Customers		-0.9	-3.0	-2.1	-1.3	-1.1	-1.6	-1.6	**-11.6**
Customer Growth/(Decline)		0.5	0.6	-2.6	-1.5	-1.2	0.7	0.0	-3.3
UPC Autoregressive Error Term		-1.4	-0.3	0.7	2.5	0.8	0.7	-2.0	1.0
UPC Forecast Error		0.9	0.2	4.0	-1.4	1.0	-3.8	-0.4	0.4
Total		-5.0	8.4	-22.1	18.7	-17.5	-9.2	-9.8	**-36.5**

North Shore experienced 3 Bcf load loss due to higher gas prices and 1.8 Bcf due to efficiency gains, against a 2.4 Bcf equivalent of gas volume increase attributed to customer growth in its territory. However, including all other factors, North Shore's demand did not change by the end of the audit period compared to the beginning fiscal year of the same period.

[150] Response to Data Request #72.

North Shore Demand Attribution Analysis during the Audit Period

North Shore Demand Attribution Analysis									
(Volumes in Bcf)	1999	2000	2001	2002	2003	2004	2005	2006	Aggregate Change
Actual	35.0	34.7	36.1	33.5	38.4	37.0	35.9	34.9	
Forecast	35.7	35.0	37.0	33.5	38.1	36.8	36.0	34.6	
Error	-0.6	-0.3	-0.8	-0.1	0.3	0.2	-0.1	0.3	
% Error	-2%	-1%	-2%	0%	1%	0%	0%	1%	
UPC Forecast Error	-0.7	-0.2	-0.8	-0.1	0.3	0.2	-0.1	0.3	
Customer Forecast Error	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Change in Actual Demand from Prior Year		-0.3	1.4	-2.7	5.0	-1.5	-1.1	-1.0	**-0.1**
Change due to:									
Weather		-0.1	4.0	-3.8	3.7	-2.2	-0.5	-0.4	0.5
Base Load Shift		0.0	-0.3	-0.3	0.0	0.0	0.0	0.0	-0.6
Price		-0.3	-1.7	0.6	0.1	-0.7	-0.4	-0.6	**-3.0**
Efficiency Improvements		-0.4	-0.4	-0.3	-0.2	-0.2	-0.2	-0.2	**-1.8**
Large Volume Customers		-0.4	-0.1	0.3	0.3	1.1	-0.1	-0.3	0.9
Customer Growth/(Decline)		0.7	0.5	0.1	0.4	0.2	0.3	0.2	**2.4**
UPC Autoregressive Error Term		-0.2	0.0	0.0	0.3	0.5	0.0	-0.1	0.4
UPC Forecast Error		0.4	-0.6	0.8	0.4	-0.2	-0.2	0.4	1.0
Total		-0.3	1.4	-2.7	5.0	-1.5	-1.1	-1.0	**-0.1**

The Utilities based the preceding demand attribution analysis on long-term forecasting method models that they update on an annual basis.[151] Three of the change-drivers in the attribution analysis, weather, price, and efficiency improvements, are explanatory variables in the regression equations used to forecast Rate 1 and Rate 2 demand. The Utilities developed year-to-year demand changes attributed to each of those variables by studying the coefficients that come out of the regression analysis, and by measuring the changes in the values of the independent variables (*e.g.*, the change in the price from one year to the next). The large-volume numbers in the tables are simply the observed changes in consumption for Rate classes 3 through 8. The Utilities believe that, by updating the forecasting models annually based on this type of analysis, they continually improve the accuracy and quality of their forecasts.

e. Liberty's Analysis

Liberty reviewed the Utilities' load forecasting procedures, models, and related documents and written procedures. Liberty interviewed personnel in the Gas Supply Department and others involved with gas supply and forecasting. Liberty examined the following features of the Utilities' load forecasting processes:

- Weather data analysis and assumptions

[151] Response to Data Request #72.

- Principal components of key forecasting models
- Methods used for forecasting
- Use of weather and other sensitivity analysis
- Evaluation of firm general, large-volume, and transportation demand.

i. Forecasting Processes

The Utilities conducted regression analysis of billing records for forecasting the most temperature-sensitive parts of the load; *i.e.*, customers under Rates 1 and 2. Liberty also expected to see more detailed examinations of regression coefficients, especially if the regression analysis produces unexpected results. The Utilities have examined the behavior of the regression coefficients. In at least one case,[152] they have examined industry studies to see whether others are getting the same results that they are.

The Utilities' "bottom-up" approach to Rates 3 through 8 is also reasonable. The Utilities have the benefit of annual elections of service levels for transportation-service customers. These elections give them frequent updates regarding customer intentions. Taking input from customer-service representatives is also a good practice.

The Utilities' recent effort to simplify the Long Term Sales Forecast constitutes a particular strength.[153] The fact that they have reduced the time required for maintenance and updating from 900 hours per year to about 100 should allow more time for study of trends revealed in the regressions. Study of identified trends and appropriate responses should be part of the Utilities' efforts in load analysis.

The significant drop in the Peoples Gas load over the audit period suggests that the utility has considerable capacity in its distribution system for additional throughput. Details of the locations and magnitudes of available capacity should be important inputs to the Utilities' marketing efforts; adding loads that do not require additional infrastructure can contribute significantly to the recovery of sunk costs.

Careful regression analysis of sendout versus temperature data is also a typical approach to peak-day forecasting. Liberty favors use of multiple years' data, and use of only the coldest days, in conducting this analysis. Use of multiple years prevents undue influence from an atypical year. Five years of data may be too many, however, as there could be considerable systemic changes; *e.g.*, in energy utilization efficiency, across such a long period. Liberty considers best practice in this area to be a three-year interval.

ii. Design Peak Day Weather Parameters

The Utilities have been adjusting their normal-year HDDs downward, in concert with drops in the 30-year average number published by NOAA. Recently, the Utilities have also adopted a 10-

[152] The Utilities examined an American Gas Association study of energy utilization efficiency in the residential sector to see whether others observed the trends that they were observing in that variable. Response to Data Request #22, Attachment A, pp. 5-6.
[153] Response to Data Request #22, Attachments A and C.

year average for normal weather; that change has reduced the normal-year annual HDD number even more.

The Utilities did not match this downward movement in the annual HDD number for the peak-day calculation. The portfolio-design value for that parameter continues to be a gas-day average temperature of minus 20 degrees Fahrenheit. The most recent day with such extreme weather was January 19/20, 1985.

The Utilities provided Liberty with 48 years of weather data (1958 to 2006). The average of the high and low temperatures for the day serves as the parameter used in calculating heating degree-days, or HDDs. The O'Hare Airport weather station data recorded 32 days where temperatures varied between minus 6 degrees and minus 18 degrees Fahrenheit. The coldest day in the data set (Saturday, December 24, 1983) experienced a high/low average of minus 18 degrees, or 83 HDDs.[154] The next coldest days in the data set (Tuesday, January 18, 1994, and Sunday, January 20, 1985) each had 81 HDDs. The next coldest day (Sunday, January 10, 1982) had 80 HDDs. The following table shows the 32 coldest days.[155]

Coldest-Day HDDs

Date	HDD	High/Low Average Temperature	Date	HDD	High/Low Average Temperature
12/24/1983	83.0	-18.0	01/28/1966	74.0	-9.0
01/20/1985	81.0	-16.0	01/16/1982	74.0	-9.0
01/18/1994	81.0	-16.0	01/30/1966	73.0	-8.0
01/10/1982	80.0	-15.0	01/21/1984	73.0	-8.0
12/23/1983	79.0	-14.0	01/19/1994	73.0	-8.0
01/23/1963	78.0	-13.0	01/09/1962	72.0	-7.0
01/29/1966	78.0	-13.0	02/02/1965	72.0	-7.0
01/15/1972	78.0	-13.0	01/19/1985	72.0	-7.0
02/03/1996	77.0	-12.0	01/05/1988	72.0	-7.0
01/16/1977	76.0	-11.0	12/21/1989	72.0	-7.0
12/25/1983	76.0	-11.0	12/09/1958	71.0	-6.0
01/15/1994	76.0	-11.0	01/10/1962	71.0	-6.0
02/02/1996	76.0	-11.0	12/19/1963	71.0	-6.0
01/15/1963	75.0	-10.0	01/29/1965	71.0	-6.0
01/17/1982	75.0	-10.0	01/30/1965	71.0	-6.0
01/20/1984	75.0	-10.0	01/21/1970	71.0	-6.0

An analyst can use these data to develop a frequency-of–occurrence chart for extreme-cold-day events. The following table shows the number of occurrences of extreme-cold-day events in the 48-year data set.

[154] Response to Data Request #27: on page 2, paragraph b, the Utilities replied that they choose to use "the 24-hour average temperature for O'Hare Airport" instead of the simple average of minimum and maximum daily temperatures to establish the coldest-day-ever in 48 years of data used in their DPD calculations. Both Utilities apply the rolling 24-hour average temperature method during January 9-10, 1982; January 15-16, 1982; and January 19-20, 1985 weather data to show the three days when the average temperature was -20 degrees Fahrenheit.
[155] Response to Data Request #67.

Frequency of Extreme Cold in the Utilities' Service Territories (1958-2006)

Data Days	17,501	
Data Years	48	
	Count	**Count/Data Years**
Days >=83 HDDs	1	1/48
Days >=82 HDDs	1	1/48
Days >=81 HDDs	3	3/48=1/16
Days >=80 HDDs	4	4/48=1/12
Days >=79 HDDs	5	5/48
Days >=78 HDDs	8	8/48=1/6
Days >=77 HDDs	9	9/48
Days >=76 HDDs	13	13/48
Days >=75 HDDs	16	16/48=1/3
Days >=74 HDDs	18	18/48
Days >=73 HDDs	21	21/48
Days >=72 HDDs	26	26/48
Days >=71 HDDs	38	38/48
Days >=70 HDDs	48	48/48=1/1

The tables show some days of extreme cold that occurred more recently than the mid-1980s dates of the Utilities' DPD criterion. Using the frequency-of-occurrence data as an indication of the likelihood of extreme cold would show that these events are relatively rare. An HDD of 83 has occurred once in 48 years, for example. As many as 81 HDDs has occurred only three times over that period, which means on average once every 16 years.

The Utilities' DPD model turns out to be very sensitive to the peak-day-sendout-per-degree-day variable. The table below shows the results of calculating peak-day sendout with 81 degree-days, instead of 85.

Design Peak-Day Using Alternative Degree-Days for FY2004-FY2006 (Dth/day)

	PGL			**NSG**		
Fiscal Year	**85 Degree-Days**	**81 Degree-Days**	**Difference**	**85 Degree-Days**	**81 Degree-Days**	**Difference**
2004	2,350,655	2,261,777	88,878	409,779	392,897	16,882
2005	2,341,808	2,253,494	88,314	414,030	396,838	17,193
2006	2,280,689	2,190,487	90,201	424,610	406,865	17,744

As noted above, the Utilities use the gas-day average of hourly temperatures for the DPD calculation in an effort to match the average temperature with the time period used to record the daily sendout data. Thus, to examine the effect of relaxing the standard slightly, the alternative degree-day number, and thus the difference, is calculated by multiplying the peak-day sendout per degree-day by four, and then subtracting the result from the DPD number computed by the Utilities, rather than recalculating it from scratch.

iii. Design Year Weather Parameters

Liberty constructed the following monthly HDDs table from the most-recent 10-year data. The table also shows the minimum and maximum values for each month and for the years in the data set.

Monthly HDDs (1996-2005 data)

Month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Maximum Actual	1,410	1,152	1,054	589	344	88	9	39	128	473	940	1,512	7,080
+2 Standard Deviations	1,501	1,247	1,101	627	413	97	11	29	158	485	993	1,455	7,054
Average	1,256	975	865	483	233	53	3	5	84	370	712	1,117	6,154
-2 Standard Deviations	1,010	703	629	338	53	6	0*	0*	10	254	430	778	5,254
Minimum Actual	1,018	732	640	374	87	8	0	0	35	286	496	933	5,564

* Since negative HDDs are not possible, the -2 Std. Dev. is set equal to zero in July and August. DR 67 "DayStats.xls" is the source for the above HDD calculations.

Actual, recorded values fall outside of the range defined by plus or minus two standard deviations from the average in two instances (the month of December and the maximum annual). If the HDD data fit a normal probability distribution,[156] then there would be only a 5 percent chance that an observation would fall outside that range. The table therefore suggests that the range defined by the average values plus or minus two standard deviations does not completely capture the range of likely outcomes for this variable.

Liberty understands that, due to observed warming trends, a number of state utility regulatory authorities have adopted 10-year average HDDs as the portfolio design standard. The PEC Utilities have recently done so. Liberty has also discussed with representatives of NOAA the observation that the month of January, in particular, has been unusually warm in the Midwest Region of the U. S., including Chicago.[157] The Northeast U. S., on the other hand, while generally observing the same warming trends, has within the last five years observed some record-cold days in January. Weather conditions could shift toward a resumption of cold Januaries in the Midwest.

Some companies have developed what Liberty believes is a better way of addressing weather uncertainties. They consider weather data as a series of occurrences, modeled and forecasted based on probability. A Monte Carlo simulation model allows them to use observed weather data to develop a probability distribution for each weather parameter of interest. For weather-sensitive segments of customer demand, this approach allows a conversion of a probability distribution of weather data to a probability distribution of expected requirements for supply. Whether a portfolio of supply capacity is adequate to the expected load then becomes a matter of risk

[156] In fact, it is well known that weather phenomena are not normally distributed. Normal probability distributions are often assumed by smaller gas distribution companies for forecasting purposes, however, when they do not have in-house expertise sufficient to work with Monte Carlo simulations.
[157] Source: Liberty telephone conversation with Anthony Arguez of NOAA, August 10, 2007.

analysis, which seeks to determine what level of certainty (probability) the company wants to assure that it provides supply to a particular customer segment.[158]

iv. Forecast Integration

Liberty did not find much focus on load research at the Utilities. Utilities personnel expressed concern about losses in customers and throughput at Peoples Gas, but do no responsive study of the details of customer behavior. For example, the previously noted regression analysis of Rates 1 and 2 customers identified a marked shift in their base-load component of the forecasting equations in FY2000 and 2001. Liberty did not see analysis seeking to determine the reasons for that shift. Similarly, both Utilities are experiencing considerable conversion of Rate 1 and 2 customers from sales service to transportation. Liberty found no analysis of the reasons for that shift or of its future direction.

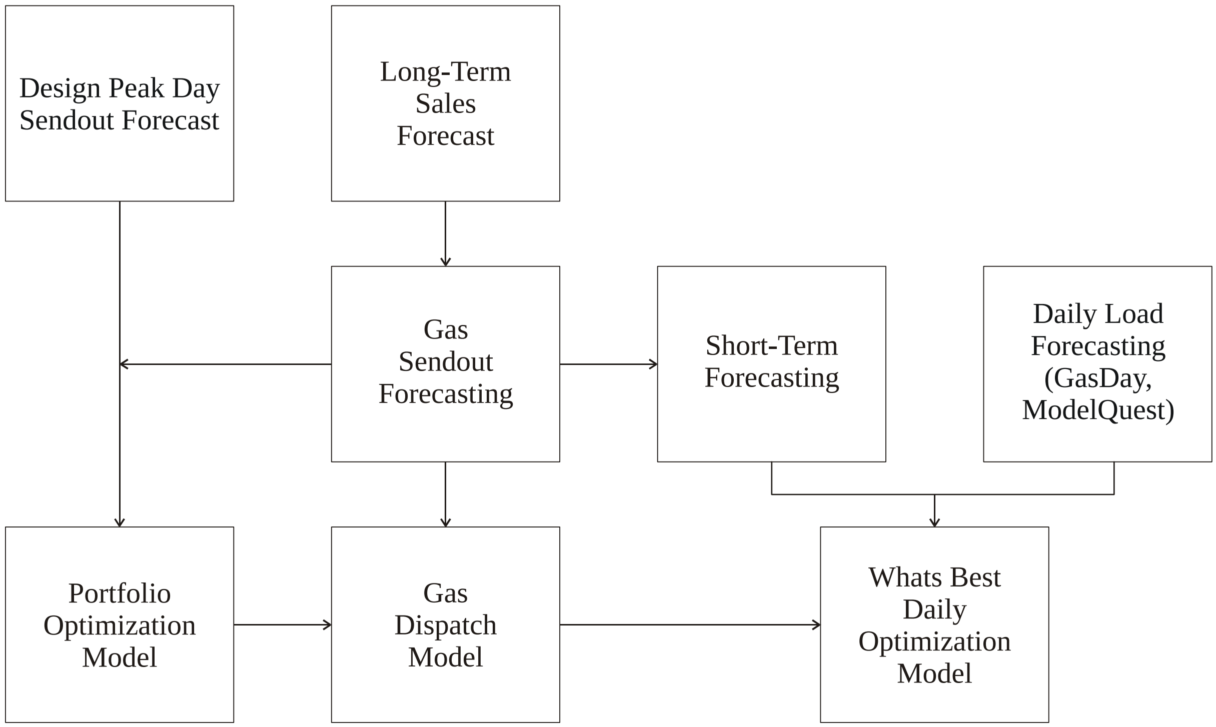
The Utilities focus considerable attention on forecasting gas sendout requirements, as discussed in the next section of this chapter. Two "drivers" for that focus are: (1) the complexity of the Utilities' supply processes, especially Peoples Gas', and (2) uncertainty about the behavior of their transportation customers; *i.e.*, their utilization of the banking provisions of their transportation tariffs. These complexities have led the Utilities' to make "stress-testing" their capacity portfolios a major part of supply planning. Such testing involves assessing portfolio performance under extreme (warm or cold weather, high or low rates of economic growth) load conditions. Supply-planning personnel showed some interest in risk-based planning, but did not identify during audit field work plans for further study.[159] However, in comments on Liberty's Draft Report, the Utilities reported that they have procured new software that may be applied to risk-based planning, and are adapting their multi-month planning model (the Gas Dispatch Optimization Model) to accept probability distributions for three inputs: (a) daily weather to forecast daily total sendout, (b) customer-owned gas supply, and (c) prices from several price points.

[158] In fact, the Utilities' demand peak day is specified in similar fashion. Regression analysis of sendout on cold days is used to relate sendout to degree-days, then a specified number of degree-days is multiplied by the resulting use-per-degree-day relationship. The regression analysis is subject to some error, however, and the Utilities' design criterion is adjusted for the possibility of error in the calculation. The initial result is adjusted upward by two times the standard error of the regression.

[159] Source: Liberty telephone conference with Marozas, Millerick, Wirick, October 5, 2007. In comments on Liberty's Draft Report, the Utilities reported that they have procured new software that may be applied to risk-based planning, and are adapting their multi-month planning model (the Gas Dispatch Optimization Model) to accept probability distributions for three inputs, 1) daily weather to forecast daily total sendout, 2) customer-owned gas supply, and 3) prices from several price points.

2. Supply Planning

The diagram below depicts the forecasting models and supply-planning processes used by the Utilities during the audit period.[160]



a. Dispatch Planning

An annual load forecast is prepared for the Annual Profit Plan. The Utilities' Gas Supply Department takes that forecast, and develops monthly customer-class demand forecasts. The annual and monthly customer-class forecasts become primary inputs for the Gas Sendout Forecasting (GSF) model. The GSF model predicts total daily sendout requirements under alternative Heating Degree Day (HDD) patterns (*e.g.*, normal, coldest-ever, warmest-ever) for each month.[161]

Throughout the audit period, Gas Supply has performed a regression analysis for each month. That analysis correlates the daily firm-load sendout (all customer classes) with the corresponding degree-days and day type. The day types in the analysis are weekdays (Monday through Thursday), non-weekdays (Saturday), and half-weekdays (Friday/Sunday). This analysis derives for each day type a constant per-day factor (base load) and a variable per-heating-degree-day factor. Gas Supply has then adjusted the per-day and per-degree-day factors from the regression analysis to reflect the volumes forecasted for off-system sales, unaccounted-for gas (UFG), and company-use gas. This process has ensured that the total of the normal-weather daily sendout volumes equals the econometrically derived annual sales volume plus unaccounted-for gas. Gas

[160] Response to Data Request #22. The Utilities will begin using the new Portfolio Optimization Model for their FY2008 portfolio re-design.
[161] Response to Data Request #22, and Interview #12-13, February 1, 2007.

Supply uses the daily (per-day and per-degree-day) factors for all service classifications combined as input into the Gas Dispatch Model.[162]

The Gas Dispatch Model (GDM) sums the daily sendouts to generate sendout requirements for each month, assuming normal weather.[163] Gas Supply then aggregates the monthly sendouts to obtain the annual sendout requirements. The Gas Dispatch Model calculates daily sendout requirements and balances the normal year's daily requirements with the gas supply available, including term-gas purchases, spot-market purchases, customer-owned gas delivered to the Utilities, and gas available for storage withdrawal or injection. The Gas Dispatch Model is updated at least monthly for "booked" volumes and revised price forecasts. From a full-year viewpoint, the Gas Dispatch Model optimizes the daily gas dispatching activity of each utility in forecasting the supply and storage mix necessary to meet the sendout requirements for each day of the forecast year.[164]

The Gas Sendout Forecasting model and the Gas Dispatch Model constitute the backbone of the Utilities' load forecasting and supply planning activities. These activities culminate in the Utilities' Annual Profit Plan. The Utilities have recently updated their Portfolio Optimization Model (POM)[165] and will use it again in FY2008, when their contracts for capacity on the Northern Border Pipeline system expire. However, for all similar strategic and portfolio analysis activities, including the regular Request for Proposals (RFP) support functions, the Gas Dispatch Model was the most important tool the Utilities used throughout the audit period.[166]

The Utilities use the Short-Term Forecasting, Daily Load Forecasting, Gas Dispatch, and What's Best Daily Optimization models to implement the Annual Profit Plan of each utility on a monthly and daily basis. The Short-Term Forecasting Model operates as a simple Excel spreadsheet file that comes from the Gas Sendout Forecasting model. It provides the particular month's gas sendout forecasts under alternative weather conditions (*i.e.*, normal, coldest-ever, and warmest-ever for that month) to the planners, schedulers, and traders in the Gas Supply Department, who use it in carrying out that month's supply activities.[167]

The Utilities use three different Gas-Day models each day to prepare load forecasts for the next seven days.[168] All three models use commercially available weather forecast data, including wind, and provide alternative estimates of total system load for the next few days. The Utilities discuss these estimates at the daily morning meeting for contingency planning of load levels different from the Gas Control Department's estimates.[169]

[162] Response to Data Request #22.
[163] In comments on Liberty's Draft Report, the Utilities pointed out that other weather patterns are used with the Gas Dispatch Model as required for portfolio, RFP and "what-if" analysis. These applications are discussed below.
[164] Response to Data Request #22.
[165] With a forecast period of one to ten years, POM was used in the last rate cases filed by the Utilities dating back to prior to the audit period. As indicated in the response to Data Request #22, this optimization model is now ready "to support the decisions required in FY2008 when much of the Utilities' Northern Border capacity expires".
[166] Interview #12-13, February 1, 2007, and Interview #27, March 16, 2007.
[167] Response to Data Request # 22, and Interview #12-13, February 1, 2007.
[168] "GasDay LR" is a linear regression daily estimation model, "ModelQuest Expert" is a non-linear statistical network model, and "GasDay ANN" is an Artificial Neural Network model. The two GasDay models are commercially available from Marquette University, Milwaukee, Wisconsin.
[169] Response to Data Request # 22, and Interview #12-13, February 1, 2007.

At least on a daily basis, the Utilities have used the What's Best Daily Optimization Model (WBDOM) to plan the mix of purchases for each day, and to help minimize shortages or over-supply situations. The WBDOM simultaneously optimizes the mix of purchases, storage injections, storage withdrawals, and peaking capacity required to satisfy system requirements at least-cost for the coming month. The model does so under the three weather patterns (normal, coldest-ever, warmest-ever for that month).[170]

b. Capacity Planning

The Utilities last performed comprehensive portfolio optimization studies in the mid-1990s, apparently in conjunction with evaluation of potential commitments to the Northern Border Pipeline system. Northern Border extended to the Chicago area in the late 1990s; the Utilities (and an affiliate) were anchor customers for that extension.[171] Since that time, the Utilities have adjusted their respective capacity portfolios. Those adjustments include the following:

- Peoples Gas
- Eliminated relatively small contracts for firm transportation (FT) on ANR and Midwestern.
- Reduced contracts on NGPL and Panhandle/Trunkline, as the Northern Border extension entered service (FY2000, 2001). The reduced contract on Panhandle/Trunkline was allowed to expire after FY2003.
- Replaced a storage service from Grands Lacs with two smaller services, one from Panhandle, and one from NGPL (FY2001).
- Subsequently moved the Panhandle storage to ANR, and combined the NGPL storage with another one on that system (FY2004).
- Shifted some storage from NGPL to ANR (FY2005).
- Retired an LPG-based peaking facility, and replaced it with contracted options for city-gate supply (FY2003).
- Varied amounts of First-of-the-Month (FOM) call options and Daily Call Options in response to their respective prices.
- North Shore.
- Eliminated FT contracts on ANR[172] and Midwestern.
- Reduced a contract on NGPL, as the Northern Border extension entered service (FY2001).
- Added a 50-day Demand Storage Service (no-notice) on NGPL (FY2001), and then increased it in FY2005.
- Split its contracted city-gate supply options between Daily Calls and FOM Calls (FY2003).

[170] Response to Data Request # 22, and Interview #12-13, February 1, 2007.
[171] So important were PEC commitments to the extension that PEC was able to influence the route of the extension, most importantly in where Northern Border would tie into Peoples Gas' facilities. Northern Border is connected to Peoples Gas' Mahomet Pipeline in three places, including upstream of the Manhattan regulator station. The maximum allowable operating pressure of Mahomet at that point is 850 psig, so supply from Northern Border is able to be injected into the Manlove Field with minimal additional compression.
[172] North Shore is not connected to Northern Border. Its Northern Border supplies are delivered via its connection to ANR.

The Utilities report[173] that they evaluated most of these changes with the Gas Dispatch Model. This model optimizes among capacity choices over one to five years, using one weather pattern at a time. In evaluating the changes, however, the Utilities would re-run the optimizations using extreme-cold and extreme-warm weather[174] in addition to the normal-weather runs. The goal of the re-runs was to ensure that the optimizations were appropriate under a range of weather conditions that the Utilities might encounter.

c. Portfolio Adjustments

The table below shows the evolution of Peoples Gas' peak-day capacity portfolio over the audit period.

Peoples Gas Winter Design-Day Portfolio during the Audit Period (MDQ in Dth/day)

	FY1999	FY2000	FY2001	FY2002	FY2003	FY2004	FY2005	FY2006
Firm Transportation	**451,056**	**555,456**	**423,448**	**377,448**	**377,448**	**320,071**	**320,071**	**320,071**
ANR	21,385	21,385						
Northern Border	98,000	215,000	215,000	215,000	215,000	215,000	215,000	215,000
Midwestern	28,600	46,000	46,000					
TTP/Citygate Swing								
NGPL	135,071	105,071	105,071	105,071	105,071	105,071	105,071	105,071
Trunkline	168,000	168,000	57,377	57,377	57,377			
Storage	**1,256,464**	**1,256,464**	**1,276,464**	**1,276,464**	**1,235,995**	**1,321,464**	**1,276,464**	**1,276,464**
ANR FSS 50 Day	75,000	75,000	75,000	75,000	75,000	160,000	200,000	200,000
NGPL DSS 50 Day	248,000	248,000	248,000	248,000	248,000	248,000	208,000	208,000
NGPL NSS 75 Day		-			-	175,000	175,000	175,000
Panhandle 30 Day		-	85,000	85,000	85,000	45,000	-	
Grands Lacs	150,000	150,000						
NGPL NSS 10 Day	90,000	90,000	90,000	90,000	69,606			
NGPL NSS 20 Day		-	85,000	85,000	64,925			
Manlove	693,464	693,464	693,464	693,464	693,464	693,464	693,464	693,464
Peaking	**500,000**	**425,000**	**440,000**	**490,000**	**505,000**	**467,000**	**520,000**	**490,000**
Weather FOM Call	[redacted]							
Daily Call Option								
Manlove – LNG	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
PNGL - PERC Peaking	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
LP Crawford	40,000	40,000	40,000	40,000	-	-	-	-
TOTAL	**2,207,520**	**2,236,920**	**2,139,912**	**2,143,912**	**2,118,443**	**2,108,535**	**2,116,535**	**2,086,535**

Compared to the beginning of the audit period (FY1999), Peoples Gas' winter FT assets were reduced by approximately 131,000 Dth/day to 320,071 Dth/day, corresponding to 20 MMDth of MSQ[175] gas volume.[176] During the same period, Peoples Gas increased the overall capability of

[173] Responses to Data Requests #284-287.
[174] As noted in the Load Forecasting section of this chapter, the Utilities' extreme-cold weather is that experienced in FY1982, which had 7,226 HDD. The extreme-warm weather is that experienced in FY1998, which had only 5,564 HDD.
[175] MSQ refers to winter Maximum Seasonal Quantities unless otherwise noted for summer or any other period during any fiscal year.

its storage assets (one ANR and two NGPL leased storage services) by about 17 MMDth winter MSQ, and eliminated 5.4 MMDth of Grands Lacs, Panhandle storage, and an NGPL leased storage service.

In FY1999, Peoples Gas' FT and storage assets were 52 percent (62 MMDth MSQ) and 38 percent (45 MMDth MSQ) of owned and contracted capacity, respectively. Peaking capacity was the other 10 percent of the total. By FY2006, these proportions had changed to 38 percent (43 MMDth MSQ) FT and 52 percent (58 MMDth MSQ) storage, while the total of FT and storage declined approximately by 6 MMDth (from 107 MMDth to 101 MMDth MSQ).

In FY2004, Peoples Gas terminated its FT contract with Trunkline, reducing its total firm supply to 322,973 Dth/day. Peoples Gas significantly increased its storage volume, from 21 MMDth MSQ to 39 MMDth MSQ, by: (1) eliminating Panhandle and consolidating the seasonal capacity of its NSS storage contracts with NGPL, and (2) not renewing the storage optimization contracts with third parties that it had previously employed for that capacity. These changes maintained NGPL's role in Peoples Gas' storage portfolio.[177]

Peoples Gas' also reduced its total peaking assets over the audit period by 10,000 Dth/day (to 490,000 Dth/day). The most notable change, however, was the decommissioning of the LP-based Crawford peaking unit. That unit had a Maximum Daily Quantity (MDQ) of 40,000 Dth/day. [redacted]

By the end of the audit period, Peoples Gas' design-day supply capacity had come down to 2.1 MMDth/day from 2.2 MMDth/day. The main contributor to the reduction was a 130,000 Dth/day drop in the FT capacity. That approximately 20 MMDth MSQ drop in FT volume was offset, however, by a 17 MMDth MSQ storage contract capacity increase, less a 5.4 MMDth storage capacity decrease.

The following table shows that North Shore's peak-day portfolio showed a similar evolution.

[176] Three FT contracts from FY1999 were eliminated in FY2001 (ANR's 21,385 Dth/day and Midwestern's 46,000 Dth/day) and FY2004 (Trunkline's 168,000 Dth/day was first reduced to 57,377 Dth/day in FY2001 before cancellation in FY2004). Northern Border started with 98,000 Dth/day capability in FY1999 and moved to its current level of 215,000 Dth/day while NGPL's MDQ was reduced to its current 105,071 Dth/day in FY2000 from 135,071 Dth/day in FY1999.

[177] Two NGPL storage services contracts (NGPL NSS 10 Day and NGPL NSS 20 Day with and MDQ of 69,606 Dth/day and 64,925 Dth/day, respectively) were converted to one 75 Day NSS contract. The two previous contracts had been used in optimization agreements with third-party operators, so the effective capacity available to Peoples Gas was only 2.6 MMDth. The optimization agreements were terminated in 2002, so the capacity available to Peoples Gas increased to 13.1 MMDth MSQ.

North Shore Winter Design Day Portfolio during the Audit Period (MDQ in Dth/day)

	FY1999	FY2000	FY2001	FY2002	FY2003	FY2004	FY2005	FY2006
Firm Transportation	**93,570**	**95,429**	**64,929**	**55,929**	**55,929**	**55,929**	**57,929**	**57,929**
Northern Border/ANR	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
ANR	35,641	37,500						
NGPL	8,929	8,929	15,929	15,929	15,929	15,929	17,929	17,929
Midwestern	9,000	9,000	9,000					
Storage	**187,637**	**187,637**	**222,637**	**222,637**	**222,637**	**222,637**	**232,637**	**232,637**
NGPL DSS -50 Days			35,000	35,000	35,000	35,000	45,000	45,000
ANR FSS-50 Days	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
Manlove-28/29 Days	62,637	62,637	62,637	62,637	62,637	62,637	62,637	62,637
Peaking	**78,365**	**92,365**	**92,365**	**84,165**	**75,365**	**87,365**	**80,365**	**92,365**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LP Peterson Rd.	40,365	40,365	40,365	40,365	40,365	40,365	40,365	40,365
TOTAL	**359,572**	**375,431**	**379,931**	**362,731**	**353,931**	**365,931**	**370,931**	**382,931**

North Shore eliminated FT contracts with ANR (35,641 Dth/day MDQ) and Midwestern (9,000 Dth/day MDQ). It consolidated the latter under the NGPL contract, which expanded from 8,929 Dth/day in FY1999 to 17,929 Dth/day in FY2005. Over the audit period therefore, North Shore's contracted FT volume declined from 93,570 Dth/day in FY1999 to 57,929 Dth/day in FY2006. This reduction corresponds to a 5 MMDth drop in gas volume from that source during the winter months.

North Shore's leased storage services in FY 1999, excluding Manlove, were only provided by ANR's FSS 50-Days contract (125,000 Dth/day MDQ or 6.25 MMDth MSQ). North Shore's FY2006 portfolio included NGPL's Demand Storage Service (DSS) 50-Days contract, which increased the total storage MSQ capability to 8.5 MMDth from 6.25 MMDth in FY1999.

NGPL serves over 25 percent of North Shore's FT and storage capacity requirements, including Manlove. In FY1999, the FT contract of North Shore with NGPL had only 8,929 Dth/day MDQ capability. North Shore doubled that FT contract and awarded NGPL a storage contract nearly as large as its FT contract in MSQ terms (2.7 MMDth FT vs. 2.2 MMDth storage gas volume).

[redacted]

Overall, North Shore's winter baseload MSQ capability (including Manlove, but excluding peaking units) dropped by 14 percent (from 21 MMDth MSQ to 18 MMDth MSQ) through the audit period. North Shore's leased storage capacity without Manlove moved up to 8.5 MMDth MSQ, while FT contracts' total MSQ capability dropped to 8.7 MMDth (from 14 MMDth). The Utilities' gas planners chose to reduce the MSQ capability of each company in approximately the same absolute amounts, which produced different percentage reductions for each. This approach reduced FT's role in winter base-load portfolio requirements while increasing storage services.

d. Plan versus Actual

Appendix IV-A contains tables that show how Peoples Gas and North Shore used their winter portfolio assets on the 25 coldest days during the FY2006 and FY2005 winter seasons.[178,179] Comparing the actual use of winter portfolio assets to design-day portfolio capability of both Utilities, the coldest-day sendouts in each year (1.488 MMDth and 1.579 MMDth for Peoples Gas, and 0.302 MMDth and 0.309 MMDth for North Shore) were well below their respective design-day requirements levels. Those requirements levels were 2.281 MMDth and 0.425 MMDth, respectively, for Peoples Gas and North Shore. This result is not surprising, because the coldest days in each of those two years had temperatures much warmer (-1 degree for 2006 and +7 degrees for 2005) than the design-day temperature of -20 degrees.

The Utilities design peak-day supply portfolios to serve their customers on the peak day. On days when demand is lower than the design peak day, there is some discretion over which assets to use. The Utilities generally compare the trade-offs between current and future pricing, and between using gas in storage early, rather than saving it for potentially colder weather later in the season. This trade-off was especially important in FY2006, when 18 of the 25 coldest days were in December, but none of those days had an average temperature below zero degrees.

These comparisons show that storage service contracts and Manlove were not used to their maximum capacity during the highest load-requirements days, with the exception of FT contracts. In addition, most peaking assets were unused. However, PERC Peaking contracts, daily-priced swing gas purchases, and Call Gas Title Transfer Point (TTP)[180] purchases (summed under the ‘Swing’ column in the tables in the appendix) were called on liberally and in large nominations. The PERC Peaking Contract provided up to 60 MDth per day of supply, but was limited to 200 MDth of supply for each winter season.

e. Liberty’s Analysis

i. Portfolio Analysis

The Reconciliation Order[181] noted substantial concern by the Utilities about the impact of new pipelines into the Chicago Market on basis differentials (*i.e.*, the difference between prices in gas-producing areas and prices at the Utilities’ city gates). As holders of pipeline capacity, the Utilities would be disadvantaged in competing for sales customers if the costs of the gas that they had available for sale reflected field-market prices plus pipeline-transportation costs, while other sellers’ costs reflected a lower city-gate price. Less apparent, but also important to the Utilities’, was concern over the future of the merchant function. The Utilities had concerns over whether they would continue to buy supply for resale to their customers, or whether third-party sellers would assume an increasing role in playing that function. A massive change in that direction

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[178] In order to meet a total sendout consisting of both retail and transportation customer deliveries to the Utilities (labeled “Cust. Supply” in the tables), customers’ requirements (labeled “Sendout” in tables), Utilities used “Field Base” and “CG Base” for FT sources, “Swing” typically is a combination of “PERC Peaking” and “Call Gas TTP” (also known as spot purchases) in addition to Manlove and contracted storage services provided by ANR and NGPL.
[179] Response to Data Request #148. The capacity sources and use were derived from load duration curves prepared by the Utilities’ staff. FY1999 through FY2002 data were not made available due to the amount of work required to prepare them.
[180] The Utilities use the term “Title Transfer Point” more-or-less interchangeably with “city gate”.
[181] Order issued March 28, 2006, in Docket No. 01-0707. See, especially, pp. 39-42.

could leave the Utilities relegated largely to moving third-party gas from their city gates to the customers' locations.[182] Large-volume customers had had access to transportation service on the Utilities' systems since the mid-1980s. Progressively smaller customers began to gain access to transportation in the years that followed, culminating in complete open-access in 2002.

These concerns led the Utilities to a significant commitment to the Northern Border Pipeline system. Northern Border, which transported gas from Canada, had entered service in the early 1980s. By the mid-1990s, however, extension of the system to the Chicago area was proposed. Participation in the extension would address both of the over-riding portfolio concerns affecting the Utilities at the time:

- Access to Canadian supplies would bring lower-cost gas, displacing the higher-cost Mid-continent and Gulf-Coast supplies on which the Utilities had traditionally depended.
- Because it was a modern, fuel-efficient system accessing a low-cost production area, Northern Border capacity would likely retain its value irrespective of what happened to the merchant function.

When the Northern Border extension entered service in late 1998 (the beginning of the Utilities' FY1999), Peoples Gas initiated the portfolio adjustments noted in the earlier part of this section (North Shore made similar adjustments):

- Eliminate FT on Midwestern, reduce it on Trunkline and NGPL. Midwestern accesses the Gulf-Coast producing region, the highest-priced region, via Tennessee Gas Pipeline; Trunkline accesses the Gulf Coast directly, and the Mid-continent via its affiliate Panhandle; and NGPL accesses both the Gulf Coast and the Mid-continent. FT on Trunkline was subsequently phased out.
- Storage capacity was shifted to NGPL, primarily for operational reasons.

These same strategic concerns (eroding basis and the future of the merchant function) also led the Utilities to increase their reliance on city-gate purchases. The Utilities put substantial portions of their pipeline capacity into Gas Purchase and Agency Agreements (GPAAs) with Enron. A key feature of these agreements was pricing the commodity delivered on a city-gate basis, rather than on field-market prices plus transportation costs. Peoples Gas put a substantial portion of its pipeline capacity into similar agreements with [redacted] and [redacted] when the GPAAs expired. Additional shifts to city-gate purchasing included the following:

- Term gas commitments (even down to relatively short, 30-day ones) were made on requirements forecasts using warmer-than-normal weather, in order to avoid having to dispose of gas that could not be sold or stored. This change increased the proportion of gas bought on a spot-market basis at the city gate.
- Requirements for peaking supplies were increasingly met with call options; *i.e.*, the right to buy gas at the buyer's option. Priced on either a daily or a monthly basis, these contracts provide for delivery at the Utilities' city gates.

The other major influences on the Utilities' capacity portfolios were: (1) the continuing loss of high-load-factor (HLF) customers, particularly by Peoples Gas, and (2) continuing improvements

[182] Interview #5, February 8, 2007.

in gas utilization efficiency by both Utilities' customers.[183] The largest part of the HLF loss had occurred prior to the audit period, but it continued during the audit period. These changes meant that: (1) both Utilities' requirements for supply capacity became more seasonal, and (2) North Shore's total requirements grew only slightly over the period, while Peoples Gas' declined. These changes could be accommodated by shifting the portfolio from FT to storage in North Shore's case, but they required shedding delivery capacity in the case of Peoples Gas.

A complicating factor for capacity planning is the Gas Bank provision in both Utilities' service offerings, under which they provide storage services for their transportation-service customers. Under this provision, the customers of both Utilities may deliver to the city gate more gas than they intend to consume; when they do so, the Utilities must store the excess. Conversely, when a customer has a positive Gas Bank balance, it can consume more gas than it delivers to the city gate. Eligible customers must nominate each day how much gas they intend to deliver to the city gate, how much they intend to consume, and how much they want to store. The contracts under which the customers use these services, which are the basis of the Utilities' requirement for storage capacity to accommodate them, are annual contracts. The Utilities therefore have more than one-day's notice of how much capacity they must allow. Planning for provision of these services is difficult, however, as delivery capacity is not commonly available for only one year. Capacity therefore cannot readily be added or subtracted as customers' elections for the services change.

The Utilities manage these uncertainties with forecasts. As discussed in the Load Forecasting section of this chapter, they prepare month-by-month forecasts of capacity requirements (including capacity required to accommodate the Gas Banks), and then manage to those forecasts. Each month's forecast is checked against the coldest-ever weather on record for that month, and the warmest-ever. Capacity is then added or shed on a short-term basis as required to accommodate customer requirements.

The Utilities address possible capacity adjustments as contracts expire. An expiring contract might be allowed to expire with no action, or it might be modified or replaced with another capacity option. Possible options, and possible combinations of options, are evaluated with the Gas Dispatch Model. The Utilities run the Gas Dispatch Model heuristically, testing different combinations of capacity options under alternative weather and other load conditions.[184]

Monthly- and daily-priced call options for peaking services are put out for bid at least once per year. Longer-term capacity requirements, such as a new storage service, may also be put out for bid.

Overall, the Utilities' portfolio analysis during the audit period has focused on tactical decisions (*e.g.,* how much of which storage service to place under contract) in a context of over-riding strategic themes. These themes include the impact of new pipelines on basis differentials, the future of the merchant function, and changes in the nature of loads, for example. As discussed in the chapter on affiliate relationships, Liberty believes that another strategic theme has been the creation of opportunities for their unregulated affiliates. As also discussed there, certain consequences of those actions, such as the provision of a number of pipeline interconnections

[183] Interview #11, February 7, 2007.
[184] Utilities' comments on Liberty's Draft Report, and their responses to Data Requests #284-289.

paid for by Peoples Gas, but used mostly by the affiliates and third-party suppliers (which include affiliates), and a cost structure that assures a large difference between the cost of gas for the Utilities' and their affiliates', seem apparent. Any harm to the Utilities' customers is, however, difficult to assess.

ii. Capacity Alternatives

Another strategic theme that has affected the Utilities' supply planning is reducing their dependence on their former affiliate, NGPL.[185] PEC's formation of NGPL offered a means for assuring access for its utilities to developing supply-source areas, first in the Mid-continent, and then in the U. S. Gulf Coast. The Utilities' distribution systems and NGPL's pipeline systems were designed together; NGPL continues to be the only pipeline system that delivers directly to Peoples Gas' city gates, rather than to the Mahomet Pipeline.

Connections to Trunkline (270,000 Dth/day) and Midwestern (300,000 Dth/day) were added to the Mahomet Pipeline prior to the audit period. Additional interconnections were added with the entry into service of the Northern Border Extension (November 1998) and subsequently. The following table shows those connections, with their capacities and attendant costs to Peoples Gas. The next figure shows the locations of the connections.

Mahomet Pipeline Interconnections[186]

Pipeline	**Year in Service**	**Capacity** (Dth/day)	**Cost** ($MM)
Northern Border (Manhattan North)	1998	600,000	1.0 (both connections)
Northern Border (Manhattan South)	1998	600,000	
Northern Border (Sharp Road)	1999	420,000	2.4[187]
Alliance Pipeline, LP	2000	600,000	(included in Northern Border Sharp Road)
ANR Pipeline (Sharp Road)	2003	500,000	9.3
Guardian Pipeline	2003	108,000	(included in ANR Sharp Road)

Peoples Gas reports that all of the costs associated with the interconnects were incurred after the last general rate case (1995); accordingly all were presented for consideration for inclusion in Peoples Gas' rate base in its pending rate case.[188]

The following chart is confidential.

[185] Interview #11, February 7, 2007.
[186] Sources: Responses to Data Requests #38, 290.
[187] Includes the cost of upgrading the lateral from Mahomet to Peoples Gas' former synthetic natural gas (SNG) plant in Will County, IL.
[188] Response to Data Request #290.

[redacted]

North Shore only connects to NGPL and ANR Pipeline. Through a displacement arrangement with NGPL, however, Peoples Gas deliveries at NGPL's Grayslake Station are treated as North Shore's Manlove withdrawal gas. NGPL's Grayslake Station is located in North Shore's service territory. This displacement agreement allows Manlove Field withdrawal gas and all other gas supplies on the Mahomet Pipeline to be delivered to North Shore even though it has no direct access to Mahomet.[189]

[189] Response to Data Request #39.

In 1998, a gate station was added just north of the Illinois/Wisconsin state line, to allow North Shore to accept deliveries directly from ANR Pipeline. North Shore owns and operates a 10-inch pipeline that connects that station to one in North Shore's service territory (Edwards Road Station). The figure below shows these connections.

The following chart is confidential.

[redacted]

Despite these various interconnections, problems with some of them and developments in the Utilities' loads have effectively reduced their capacity alternatives over the audit period. In particular,

- With the entry into service of the Northern Border Extension, flow on the Midwestern system was reduced considerably, and is actually reversed for part of every year. Now, rather than providing another source of supply for Peoples Gas and North Shore, Midwestern largely moves Canadian gas to markets in the Northeast U. S. by virtue of its connection to the Tennessee Gas Pipeline system.
- While the Trunkline system accesses the Gulf Coast region, competition among gas sources in the Chicago Market makes the price at Gulf Coast trading points often higher than the price at Chicago city gates. Trunkline also connects to the Panhandle Eastern system, which accesses the Mid-continent producing region and storage in Michigan. However, Trunkline/Panhandle supply could not enter Peoples Gas' Mahomet/Manlove complex on cold days in 2003 and 2004. Due to non-performance, Peoples Gas chose not to continue service after 2004.[190]
- Alliance enters Peoples Gas' system at a point that only allows gas to flow to the city of Chicago or to ANR storage via the Sharp Road Interconnect. Due to low hourly takes in the summer and gas quality issues, annual contracts are inadvisable. However, Alliance is part of Peoples Gas' portfolio via the Citygate Call Gas RFPs and daily Citygate spot purchases during cold weather months.
- While the interconnect with the Guardian Pipeline is bi-directional (Peoples Gas can either receive gas from or deliver gas to Guardian), it runs from Joliet, IL to Ixonia, WI. Thus, it primarily moves Canadian gas arriving on the Alliance and Northern Border systems from Illinois to Wisconsin. Peoples Gas can receive system supply and customer-owned gas from Guardian, but the PEC subsidiary that uses Guardian the most is affiliate Peoples Energy Wholesale Marketing (PEWM), who uses it to move gas delivered to Mahomet via Northern Border to PEWM's customers in Wisconsin.

The Utilities' dependence on NGPL has increased over the audit period. In FY1999, NGPL supplied 19 percent of Peoples Gas' peak day. By FY2006, that proportion had increased to 21 percent. In FY1999, NGPL supplied only 2.2 percent of North Shore's peak day; by FY2006, that proportion had increased to 15 percent.

The nature of NGPL's services is more critical than those proportions suggest. NGPL serves both Utilities' city gates directly, in addition to serving Manlove Field and connecting to Mahomet. Thus, NGPL must meet any peak-day requirement that exceeds the capacity of the Mahomet Pipeline. Moreover, NGPL offers the flexible no-notice storage service that the Utilities require for balancing.[191]

As among the PEC companies, the principal beneficiaries of the various Mahomet interconnections have been the Hub and the affiliates. In particular,

- Exchanges of gas among the various interconnects have generated 11 to 32 percent of Hub revenues.

[190] Source: Company comments on Liberty's Draft Report.
[191] Interview #11, February 7, 2007.

- Park and loan services, which combine transportation on Mahomet with storage, have increased from a low of about 17 percent of Hub revenues to about 60 percent in FY2006.
- As noted above, affiliate PEWM is the principal PEC user of the connection to the Guardian Pipeline. PEWM also stores gas in Louisiana, in order to back up its flowing supplies and to provide options when prices are increasing,[192] that it can access via Mahomet's interconnections with Midwestern and Trunkline.
- Affiliate Peoples Energy Resources Corporation (PERC) provides fuels-management services to the Elwood electricity Generating Station, which PERC also partially owned;[193] Elwood is supplied via a lateral from the Mahomet Pipeline, and Mahomet's various interconnections provide abundant choices for PERC's acquisition of supplies for its service to Elwood.
- Despite ending its use of Midwestern for system supply after the FY2001 winter, Peoples Gas retained transportation service on that system until 2005 in order to facilitate movement of supply from the Alliance pipeline, which has been a source of supply for transportation-service and Hub customers, but not for the Utilities.[194]

An alternative form of supply capacity that the Utilities accessed is options. In FY2006, call options accounted for 6 percent of Peoples Gas' peak-day supply resources, and 14 percent of North Shore's. Capacity covered by options can be provided to both Utilities on any pipeline system that is connected to Mahomet. Thus, the additional pipeline connections to Mahomet have increased the Utilities' alternatives for this type of capacity.

Since 1996, Peoples Gas has bought peaking gas supply from its affiliate, Peoples Energy Resources Corporation (PERC). The contract that governed this supply relationship was presented to and approved by the ICC.[195] The contract had an initial term of three years, and continued year-to-year thereafter, unless canceled by either party on 12 months' written notice to the other.

Pricing under the PERC contract was similar to that under contracts with third parties. The PERC contract provided for a fixed charge of $200,000 per month during the service period of October 1 to April 1. The maximum daily quantity was 60,000 Dth/day, and the maximum seasonal quantity was 200,000 Dth. Converting the fixed charge to a unit rate yields $0.111 per Dth.[196] Recent third-party peaking supply contracts have had lower reservation charges. For FY2005, those charges ranged from $0.0200 to $0.0400 per Dth; for FY2006, they ranged from $0.0175 to $0.0250 per Dth. The commodity price under the third-party contracts was the Chicago City Gate daily index price as published by *Gas Daily*; however, the PERC contract was for <u>the lesser of</u> the *Gas Daily* index or $5.00 per MMBtu. Thus, the PERC contract was comparable to a daily call with a $5.00 per MMBtu cap. The value of such a call has risen considerably since signing of the original contract, as the parties never changed the pricing provision. Peoples Gas reported

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[192] Interview #64, August 22, 2007.
[193] PERC's interest in the Elwood Station was sold earlier in 2007. PERC continues to provide fuels-management services to the facility, however.
[194] As noted above, Peoples Gas now accepts bids for capacity options and winter-period spot-market supplies delivered on Alliance.
[195] Order, dated May 27, 1997, in Docket No. 96-0452.
[196] $200,000 per month/(60,000 Dth/day)*(30 days/month) = $0.111 per Dth

that it only exercised the option when the price was above $5.00.[197] Peoples Gas also reported that the PERC contract had considerable operational benefits. PERC terminated the contract at the end of September 2006, however.

iii. Portfolio Modification

The broad changes in the Utilities' portfolios (a reduced peak day in the case of Peoples Gas, and a shift from FT to storage in both portfolios) comport with the changes in the two Utilities' loads. Peak-day tends to change in proportion to the number of customers. Moreover, the proportion of winter-season capacity that must be provided by storage increases as high-load-factor customers leave the system. The following table collects some of the overall-change relationships. The Utilities generally made changes as contracts expired, although some capacity has been retained for operational purposes or released to other users for a period until a contract expired.[198]

Comparisons FY1999 to FY2006

	Number of Customers	Peak-Day Supply Capacity	Winter-Season Supply Capacity
Peoples Gas	-2.3%	-5.5%	-4.7%
North Shore	+6.0%	+6.5%	+1.8%

When presented with specific change opportunities, the Utilities would typically develop capacity alternatives, and test them against each other using Gas Dispatch Model scenarios. In FY2004 and 2005, for example, Peoples Gas allowed to expire a storage contract on the Panhandle system, and adjusted quantities between an ANR FSS contract (ultimately increased) and an NGPL DSS contract (ultimately decreased). As noted above, Peoples Gas eliminated the Panhandle storage because of performance problems; the analytical problem addressed was how much ANR FSS and how much NGPL DSS to secure under contract.

The Utilities reported:[199]

> *… twenty-seven Gas Dispatch Model scenarios … using varying levels of NGPL NSS, ANR FSS, and NGPL DSS leased storage services under normal, warm, and cold weather patterns were run between October 2002 and November 2003 to help determine the best combination of leased storage services. … The twenty-seven Gas Dispatch Model scenarios … examined NGPL DSS capacity between 8 BCF and 12.4 BCF, and ANR FSS capacity between 8 BCF and 12.25 BCF. … The final management decision [was] for 10 BCF in ANR FSS and 10.4 BCF in NGPL DSS …*

What Liberty did not find was any analysis of whether the incremental Manlove capacity used for the Hub could substitute for any of the leased storage capacity.[200] As detailed in Chapter VII,

[197] Response to Liberty question dated November 4, 2007, referring to the response to Data Request #20.
[198] The FT contract on the Midwestern system, for example, stopped being counted at the end of FY2001, but the contract continued until 2005. The capacity was used to facilitate movements of gas received from Alliance until the Sharp Road interconnect with ANR provided another outlet for the Alliance gas.
[199] Response to Data Request #284.
[200] According to the Utilities, Manlove Field's operating characteristics are not comparable to ANR FSS and NGPL DSS, so such analysis is not useful.

it appears that the storage capacity being used for the Hub is less expensive than the leased storages. Such a differential would make substitution of any amount of additional Manlove storage for leased storage beneficial to the Utilities' customers.

The Utilities have understood the need to optimize the portfolios as a whole. Reported uses of the Portfolio Optimization Model include: (1) identifying the optimal supply, transportation, and storage mix given firm sendout requirements, and (2) identifying the most advantageous and least cost-effective portions of the portfolio to aid in negotiations and portfolio refinement.[201] The Portfolio Optimization Model is the one that the Utilities have not used since the mid-1990s, but are updating for use in analyzing possibilities for when the Northern Border contracts expire.

There is a difference of opinion within the staff of the Gas Supply Department about the ability to substitute incremental Manlove storage capacity for some of the leased storages. In response to Liberty's request for any studies of that possibility, the Utilities responded:[202]

> *No such studies were performed during the audit period. Manlove capacity is not fungible with pipeline storage services. For example, pipeline storage services have longer withdrawal seasons that extend both prior to and continue after the Manlove withdrawal season. These services also have varying levels of daily no-notice injection and withdrawal capabilities, and annual cycling requirements of 50% or less. However, Peoples Gas took current Manlove Field … operating parameters into consideration when developing its existing supply, transportation, and storage portfolio and in its planning models. … Using additional Manlove capacity for system requirements or displacing purchased services with Manlove capacity would have adverse effects on the rest of the portfolio…*

The substitution possibility thus appears to have been the subject of qualitative arguments, but not of quantitative analysis. Taken together, the data-request responses and discussions with the staff of the Gas Supply Department, suggest that the Utilities study individual portfolio modifications as opportunities present themselves, but overall optimization was last studied in the mid-1990s.[203]

iv. Portfolio Fit and Analysis

That overall optimization is studied only every 10-15 years matters if the results of failing to optimize are that the Utilities are left either with significantly more or less gas-supply capacity than their customers require. Given the decline in Peoples Gas' load since its last optimization studies, the question of possible excess capacity in its portfolio certainly is one that has merited examination.

Some utilities that perform comprehensive optimization studies do so as part of integrated resource planning that may be required by their regulatory commissions. These studies also assist in documenting the decision process for supply-capacity commitments, which has relevance in

[201] Response to Data Request #22, Attachment C, p. 4.
[202] Response to Data Request #285.
[203] See, *e.g.*, the Utilities' response to Data Request #22, Attachment C, page 4.

supporting those commitments in gas-cost recovery proceedings. The studies use design annual-weather criteria, just as peak-day studies use a peak-day design criterion. The question studied is whether the capacity portfolio is appropriate to the company's service obligation under design-weather conditions. Liberty found nothing of this nature at the Utilities.

The Utilities do not prepare comprehensive estimates of the capacity required to meet their service obligations. They prepare estimates of the capacity required by their customers under normal weather conditions, and then "stress-test" those estimates under extreme weather conditions. The tests are appropriate to the purposes they serve, but do not substitute for a careful definition of the annual service obligation, which they could then compare to the owned and contracted capacity portfolio.

In the absence of a more comprehensive assessment of the fit between the Utilities' service obligations and their owned and contracted portfolio, Liberty devised a test for the possibility of excess capacity. Liberty's test uses the Utilities' planned use of their portfolios as a "proxy" for the larger number. The service obligation is to the same customers, with the same load profiles, as are considered for the planned-use estimates.[204] Trends in the planned-use estimates can then be compared to trends in owned and contracted capacity to see whether "owned and contracted" is being adjusted in response to observed changes in "planned use."

The first table below shows planned use for Peoples Gas' capacity portfolio, and the second shows owned and contracted capacity. The tables present winter-period data. Similar tables for North Shore follow.[205]

[204] The principal difference between planned use and service obligation is normal weather (for planned use) versus design weather (for service obligation).
[205] "Detailed Explanation of Changes Made to Winter Capacity Tables." provided in response to Liberty's Draft Report, and response to Data Request #310.

Planned Use of Winter Capacity - Peoples Gas
(MDth)

Capacity Requirements	**FY99**	**FY00**	**FY01**	**FY02**	**FY03**	**FY04**	**FY05**	**FY06**
Customer Requirements								
Retail	[redacted]							
Transportation Sales Including Standby Commodity								
Storage & Peaking Withdrawal Requirements for Transportation Customers								
Transportation Customers use Full Allowable Bank								
Sub-total								
Other Requirements								
UFG	[redacted]							
Compressor Fuel								
Company Use								
Sub-total								
Total Requirements	[redacted]							
Transportation Customer Supply	[redacted]							
Net Capacity to be Provided by PGL	113,841	112,295	103,960	104,732	106,025	107,722	108,280	104,475

Owned and Contracted Winter Capacity - Peoples Gas (MDth)

	FY99	FY00	FY01	FY02	FY03	FY04	FY05	FY06
Firm Transportation (1)	**62,006**	**78,342**	**58,768**	**51,157**	**50,852**	**42,675**	**41,337**	**42,744**
ANR (2)	3,208	3,208						
Northern Border (2)	14,700	32,250	32,250	32,250	32,250	32,250	32,250	32,250
Midwestern (2)	4,290	6,900	6,900					
NGPL (2)	20,261	15,761	15,761	15,761	15,761	15,761	15,761	15,761
Trunkline	25,200	25,200	8,607	8,607	8,607			
Reduction for Filling Manlove (3)	-5,652	-4,976	-4,750	-5,460	-5,765	-5,335	-6,673	-5,266
Storage (4)	**45,100**	**46,387**	**46,137**	**46,137**	**45,531**	**59,712**	**58,362**	**58,362**
ANR FSS 50 Day	3,750	3,750	3,750	3,750	3,750	8,000	10,000	10,000
NGPL DSS 50 Day	12,400	12,400	12,400	12,400	12,400	12,400	10,400	10,400
NGPL NSS 75 Day						13,125	13,125	13,125
Panhandle 30 Day			2,550	2,550	2,550	1,350		
Grands Lacs	4,500	4,500						
NGPL NSS 10 Day	900	900	900	900	696			
NGPL NSS 20 Day			1,700	1,700	1,299			
Manlove	23,550	24,837	24,837	24,837	24,837	24,837	24,837	24,837
Peaking	**10,920**	**6,170**	**3,610**	**6,690**	**10,155**	**11,127**	**14,920**	**11,380**
[redacted]								
LNG (5)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
LP Crawford	170	170	170	170				
PNGL*	200	200	200	200	200	200	200	200
TOTAL**	**118,026**	**130,899**	**108,514**	**103,984**	**106,538**	**113,514**	**114,619**	**112,486**

* Also known as "PERC Peaking" contract

** Owned and contracted for winter season (Nov-Mar) in each Fiscal Year

Notes:

(1) Does not include reduction for pipeline capacity used to fill leased storage Nov-Mar.
(2) This capacity was released to Enron and others from the winter of 2000 through 2006 in return for Citygate deliveries.
(3) Based on the 0&12 forecast for normal weather
(4) Does not include reductions for filling leased storage or leased storage April withdrawals.
(5) LNG normal weather planned volumes are 151 MDth total Nov-Mar. The remainder is reserved for peak cold weather.

Planned Use of Winter Capacity - North Shore
(MDth)

Capacity Requirements	**FY99**	**FY00**	**FY01**	**FY02**	**FY03**	**FY04**	**FY05**	**FY06**
Customer Requirements								
Retail	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Sales Including Standby Commodity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Storage & Peaking Withdrawal Requirements for Transportation Customers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transportation Customers use Full Allowable Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sub-total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Requirements								
UFG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Compressor Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Company Use & Franchise Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sub-total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Requirements	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Transportation Customer Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Net Capacity to be Provided by NSG	20,786	20,989	21,135	19,738	20,327	19,575	20,379	20,328

Owned and Contracted Winter Capacity – North Shore
(MDth)

	FY99	FY00	FY01	FY02	FY03	FY04	FY05	FY06
Firm Transportation (1)	**13,688**	**14,001**	**9,083**	**7,790**	**7,763**	**8,000**	**8,173**	**8,340**
Northern Border (2)	6,000	6,000	6,027	6,089	6,027	6,027	6,000	6,000
NGPL (2)	1,339	1,339	2,389	2,389	2,389	2,389	2,689	2,689
Midwestern (2)	1,350	1,350						
ANR- TransCanada (2)	5,346	5,625						
MGT/El Paso (2)			1,350					
Reduction for Filling Manlove (3)	-348	-314	-683	-689	-654	-417	-516	-349
Storage (4)	**7,700**	**7,816**	**9,566**	**9,566**	**9,566**	**9,661**	**10,066**	**10,066**
ANR FSS 50 Day	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250
NGPL DSS 50 Day			1,750	1,750	1,750	1,750	2,250	2,250
Manlove	1,450	1,566	1,566	1,566	1,566	1,661	1,566	1,566
Peaking	**530**	**230**	**230**	**2,400**	**3,455**	**5,880**	**2,150**	**3,902**
10-Day FOM Citygate Call	[redacted]							
20-Day FOM Citygate Call								
Weather Call								
Citygate Call Option								
Daily Citygate Purchases								
LP Peterson								
TOTAL*	**21,917**	**22,047**	**18,879**	**19,756**	**20,784**	**23,541**	**20,389**	**22,308**

* Owned and contracted for winter season (Nov-Mar) in each Fiscal Year

Notes:

(1) Does not include reduction for pipeline capacity used to fill leased storage Nov-Mar.

(2) This capacity was released to Enron and others from the winter of 2000 through 2006 in return for Citygate deliveries.

(3) Based on the 0&12 forecast for normal weather.

(4) Does not include reductions for filling leased storage or leased storage April withdrawals.

For Peoples Gas, the essential finding is that planned use of winter capacity declined over the audit period from 113.8 MMDth to 104.5 MMDth, or 8.2 percent. Over this time, winter-period owned and contracted capacity declined from 118.0 MMDth to 112.5 MMDth, or 4.7 percent. For North Shore, the findings are that planned use declined by 2.4 percent, while owned and contracted capacity actually increased, by 1.8 percent. These differences are small, but they are clearly in the same direction, *i.e.*, planned use of the capacity is declining faster than owned and contracted capacity.

Several aspects of the planned-use data, such as the significant variations in unaccounted-for gas (UFG), raise questions that the Utilities cannot readily answer.[206] Moreover, certain mitigating factors, such as downward revisions in the annual number of HDDs in normal weather in FY2001 and FY2006 affect the planned-use data but not the owned-and-contracted. Data regarding the size of customer bank balances support the Utilities' reservation of capacity for transportation-customer Gas Bank accounts.[207]

[206] Liberty telephone conference with Marozas, Millerick and Wirick, October 5, 2007.
[207] Response to Data Request #315.

C. Conclusions

1. The Utilities' annual demand forecast lacks load research and needs other improvements. *(Recommendation IV-1.)*

Regression analysis of customer billing records, which is the basis of the Utilities' annual demand forecasts, is the standard method for this type of forecast in the gas industry. However, the Utilities' implementation of the method is too shallow to yield any insights into ongoing changes in their customers' requirements. Load research, or even any interest in load research, is missing. The Utilities do not study trends in their loads sufficiently to be able to respond to them. For example, the Utilities simply do not study the reasons for and rates of migration from sales service to transportation service. The result was that, at least through FY2005, the Utilities usually forecasted sales too high, even after adjustment to actual weather.

The change from 30-year average to 10-year average HDDs for normal weather is in the proper direction (less requirement for supply) but for the wrong reasons. A number of utilities, with the support of their regulatory commissions, have moved from the 30-year average to the 10-year average. The apparent warming trend is the reasoning behind this change, but the Utilities should not embrace it just because everyone else is doing it. The Utilities should adopt a risk-based approach to supply planning, which considers weather history as a distribution of occurrences for the Utilities to use to develop probability distributions for supply planning into the future. Because the Chicago area is so amply served with pipeline systems, a risk-based approach would result in a reduction in advance commitments for supply, which is the same outcome that is resulting from changing from 30-year HDDs to 10-year HDDs.

As discussed in the chapter of this report on affiliate relationships, the Utilities' evident lack of interest in load research has served to benefit their affiliates. In the Utilities' case, inadequate gas-supply planning results in commitments to supply that are too large. The extra commitments benefit affiliates in at least the following two ways:

- Excess commitments to capacity by the Utilities means that affiliates can buy on an interruptible basis but sell on a firm basis, knowing that they will never be interrupted.
- Excess supply commitments by the Utilities result in higher selling prices to the Utilities' retail customers. This means larger profit margins for the affiliates who sell in competition with those prices, and an easier sales proposition to get customers to switch from utility sales service to transportation.

2. The Utilities' peak-day demand forecast is too conservative. *(Recommendation IV-2.)*

The Utilities forecast their Design Peak Day (DPD) based on a weather event that has happened twice in 48 years, most recently more than 20 years ago. The forecasting method then adds two standard deviations to that result to ensure that, if such a weather event occurs, there is a 97.5 percent probability that the sendout experienced by the Utilities will not exceed the estimate. This degree of conservatism is not consistent with the Utilities' locations and access to alternative supplies.

Details of the DPD calculation also seem oriented toward producing a result that is too high. The DPD portfolio standard is commonly estimated by regressing sendout against weather on the coldest days. The Utilities used the coldest days in each of the last five years in the regression analysis. Good forecasting practice for this standard requires the use of more than one year to reduce the risk that something abnormal in one year affects the calculation too much. Best practice uses two or three years. Adding older data for the regression includes usage for which several years of energy-efficiency improvements are not included. Those data will tend to make the resulting DPD too large.

3. The Utilities may not acquire assets to meet ratepayers' gas supply needs in a manner that ensures supply adequacy and reliability without over-supply at least cost. *(Recommendation IV-3.)*

Peoples Gas was losing customers and throughput volume through the audit period. Peoples Gas' own Demand Attribution Analysis quantified the effects of different factors in that loss. Liberty does not have customer-numbers and throughput data back to the mid-1990s when the Utilities were examining their capacity portfolios as part of their decision process for entering the Northern Border contracts. However, Liberty expects that the losses in customers and throughput began before the earliest years of the audit period. Comparable data for North Shore show increases in the number of customers, but flat throughput. In these circumstances, the Utilities' responsibility was to reduce capacity in the case of Peoples Gas, and to shift the capacity mix from firm transportation to storage, to reflect the increasing seasonality of their loads, for both Utilities.

Asset-management agreements, first with Enron (the GPAA contract) and then with [redacted] and [redacted], would have limited the Utilities' ability to adjust their portfolios while the agreements were effective. Such limits are standard provisions in those agreements, and economic parameters of the agreements would have reflected the asset-manager's access to capacity. Access to the Utilities' gas-supply portfolios, and expectations about Peoples Gas' and North Shore's use of those portfolios, would have been key inputs into an asset manager's offer for the right to operate the capacity. The asset manager then protects what it has bought with contract provisions limiting the capacity owner's right to change the capacity portfolio.

The Utilities clearly had the ability to adjust the portfolios between the effectiveness of the GPAA agreements and the succeeding ones, because they actually made a number of adjustments. The Utilities reported that adjustments contracted in FY2004 and FY2005 (preceded by extensive analysis in FY2003 and 2004) re-balanced their contracts for storage services between ANR and NGPL, for example. The Utilities also reported that, among the options studied were reductions in the total quantity of storage capacity under contract.[208] Thus, Liberty concluded that the Utilities had the option to reduce capacity in that and other ways, had they sought to do so.

Peoples Gas personnel argued that the remaining capacity at that point (FY2004/2005) was all necessary for operational reasons. In comments on Liberty's draft report, the Utilities provided scenarios that they examined at the time,[209] but none of the analyses demonstrated that all of the

[208] Liberty telephone conference with Wirick, Marozas and Millerick, on October 3, 2007.
[209] Response to Data Request #284.

retained capacity was required in order to meet service obligations. Thus, Liberty concluded that Peoples Gas had an opportunity to reduce the total amount of capacity owned and under contract, but elected not to do so.

Owned-and-contracted capacity has been declining, but not as fast as customer requirements.

4. **The structure of the gas-supply portfolios used by the Utilities to meet forecasted peak-day and annual demands are reasonable, but may not be optimal.** *(Recommendation IV-4.)*

The structures of the Utilities' gas-supply portfolios for retail customers are as follows:[210]

Design-Day Portfolios, FY2006

	Peoples Gas		North Shore	
	MDth	%	MDth	%
Term Supply	320	15	58	15
Re-deliveries from Storage	1,277	61	233	61
Peaking	490	24	92	24
Total	2,087	100	383	100

A very broad guideline for gas distribution companies' peak-day capacity portfolios is one-third flowing gas (referred to by the Utilities as "Term Supply"), one-third re-deliveries from storage, and one-third peaking. Relative to that guideline, the Utilities are long on re-deliveries from storage, and short on both flowing gas and peaking capacity.

The comparable numbers for winter-period capacity are as follows:[211]

Winter Capacity 2005/2006

	Peoples Gas		North Shore	
	MMDth	%	MMDth	%
Term Supply	42.7	38	8.3	37
Re-deliveries from Storage	58.4	52	10.1	45
Peaking	11.4	10	3.9	18
Total	112.5	100	22.3	100

Liberty knows of no guideline for winter-period capacity, which is understandable given that gas distributors' loads vary considerably with latitude (southern utilities have less seasonal variation), and the presence (or absence) of high-load-factor customers.

Peoples Gas and North Shore have three important difficulties in developing optimal portfolios for their retail customers:

- The Utilities' tariffs for gas transportation service provide that those customers can store gas on their systems. Thus, the Utilities have to reserve storage capacity to accommodate those balances.

[210] Utilities Kickoff Presentation, January 17, 2007, p. 45.
[211] Response to Data Request #316.

- There is a very large difference between the Utilities' typical summer-day load and their design peak days. The latter is about 10 times as large as the former.
- There is very large day-to-day variation in sendout, in the shoulder months (October and April) as well as during the winter months.

The Utilities also have an important asset for assembling effective portfolios that many gas distributors do not have, and that is connections to a number of different pipelines. Peoples Gas is connected to seven pipelines (six through its Mahomet Pipeline and one (NGPL) directly) through gate stations that have a combined delivery capacity of 6,614 MDth/day.[212] This capacity is over three times its design-day requirement for supply. North Shore connects to two pipelines, through gate stations with a combined delivery capacity of 1,505 MDth/day,[213] which is almost four times its design-day requirements. By virtue of a displacement agreement with NGPL, North Shore can access all of the supply sources connected to Peoples Gas' Mahomet Pipeline through NGPL's Grayslake Station. The capacity of North Shore's connection to NGPL at Grayslake is 375 MDth/day, which is almost as much as its design peak day.

The Utilities have moved some way toward taking advantage of this potential. The steps they have taken include the following:

- Increased use of capacity options for peaking: Peoples Gas, in particular, formerly contracted for storage services, and then worked with a third-party asset manager to configure the peaking services it needed. With capacity options, Peoples Gas now considers all of the offers from providers of peaking services that it had previously, and offers using delivery systems that are not connected to storage. Thus, the use of capacity options has increased the number of choices that Peoples has for this critical component of its supply portfolio.
- Increased use of spot-market purchases: Throughout the audit period, both Utilities made their term (one month or longer) purchases based on warmer-than-normal requirements estimates. This adjustment increased their proportions of spot-market purchases, both in field markets and at the city gate. Additional spot-market purchases provided more opportunity for competition for this component of supply.

The Utilities can and should go further in these directions. In particular, the Utilities could potentially:

- Increase the use of capacity options for peaking supplies.
- Increase spot-market purchases, especially when combined with hedging to fix prices when they are attractive.
- Refine the operational issues that require committed capacity for retail customers.
- Isolate operational issues associated with Hub operations and on-system transportation, and refine rate design to isolate the cost consequences of those issues.
- Reduce and re-balance their requirements for pipeline capacity and re-deliveries from storage for sales-service customers.

[212] Response to Data Request #38, Attachment 3.
[213] Response to Data Request #38, Attachment 4.

The current structure of the Utilities' gas-supply portfolios is not unreasonable. Their owned and contracted capacity resources include a mix of flowing gas, re-deliveries from storage, and peaking supplies that are within a reasonable range, and the changes in the mix, both in its proportions and in the nature of each type of capacity, are in the correct directions. The question is whether they should do more.

5. The Utilities' winter demand portfolio planning allows sufficient flexibility to provide supply during a warmer-than-normal month without risking over-supply.[214]

The Utilities perform annual gas-supply planning based on normal weather. They use options on supplies delivered to their city gates to accommodate the design peak day. They make any term (greater than one month) commitments for commodity assuming warmer-than-normal weather, so that they avoid having to dispose of excess gas.

Prior to the beginning of each month, the Utilities use their "What's Best" Daily Optimization Model to compute the optimum dispatch for the month under three different weather patterns: normal, coldest-ever for that month, and warmest-ever for that month. They use actual, recorded weather for each of the patterns in order to capture the variation experienced for each of the patterns. Other inputs include prices at supply points, including the cost of gas in storage, storage levels, and various contract and other constraints that affect supply choices. Gas Supply provides the results of the optimizations to the Morning Meeting group, which includes all personnel involved in selecting and dispatching supplies.

The coldest-ever load forecast uses the actual daily HDD from the coldest of the respective month on record. Using current load factors, such as use per HDD for each customer class, with the historical daily HDD provides an estimate of the highest monthly load that each Utility should reasonably expect to stand ready to serve. The flexibility in the Utilities' owned and contracted resource portfolios is used first to accommodate an increased load, but additional options include increasing swing purchases, reducing injections into storage, increasing withdrawals from storage, calling on peaking resources, and buying gas on the daily spot market.

The warmest-ever forecast again uses actual daily HDDs from the warmest of the respective month on record, with current load factors. Again, resource flexibility is used first to deal with an unusually low load, but contingency measures include reducing swing purchases, reducing withdrawals from storage, increasing injections into storage, and off-system sales.

The three dispatches (normal weather, coldest-ever and warmest-ever) are updated daily through the month. Each day, the Utilities' dispatchers and traders receive new optimizations that incorporate actuals from the previous day, and present an updated range of possibilities for the balance of the month. In this way, they can make their choices in ways that do the best that they can for that day, but preserve as much flexibility as possible for the rest of the month.

6. The Utilities do not have sufficient internal controls in place to ensure that they follow their operational supply plans while keeping the Utilities from using ratepayer storage and supply assets for non-ratepayer benefit. *(Recommendation IV-4.)*

[214] This discussion is based on the Utilities' response to Data Request #22, Attachment A, as amplified in a telephone conference between Liberty and Wirick, Marozas, and Millerick.

All assets are used in the provision of all services. The Utilities' operational supply plans for their retail customers are primarily the monthly dispatch plans. They execute those plans on facilities that are, at the same time, serving two other sets of customers, on-system transportation customers and Hub customers. At the same time that the Utilities are trying to dispatch the optimum mix of supplies to retail customers, they are also trying to deliver, or store, gas to where the other two sets of customers want it, and when they want it.

This use of the same facilities to serve three sets of customers is not a problem as long as service to each of the three is not compromised by service to the other two. By virtue of the Utilities' ICC tariffs, retail and on-system transportation customers have the same priority; the issue, then, is whether service to Hub customers compromises the quality of services to the other two. Liberty found nothing to suggest that was the case.

The Utilities' (unwritten) policy is that Hub services are secondary to on-system services. Liberty's concern is that there is plenty of capacity to accommodate all services because the Utilities are holding at least some excess capacity.

D. Recommendations

IV-1 Implement a program of load research and forecasting improvements.

A proper program of load research and forecasting improvements would result in lower gas-supply costs for the Utilities. Liberty expects that "tighter" load forecasts will reduce expected requirements for supply, which, in turn, will lower supply costs.

Load research could improve marketing and system utilization. Load research will reveal areas where the Utilities have capacity available to serve different types of loads, which, in turn, could lead to targeted marketing and development of gas-utilization projects (such as gas-fired cogeneration and fuel cells).

In view of these potential benefits, Liberty recommends that the Utilities develop a coordinated program of load research and forecasting improvements within six months of the date of this report. Appropriate linkages to marketing and gas-utilization project development should be part of the presentation.

IV-2 Justify the Design Peak Day (DPD) estimation methods.

The Utilities should prepare a report on industry practices for DPD estimation for presentation in their respective next Gas Cost Reconciliation proceedings. Liberty believes that both the addition of two standard deviations to the results of the regression, and the use of five years of coldest days rather than three, makes the DPD calculation produce an unreasonably high result, probably by at least 10 percent. The two standard deviations added to the regression result increase that number by 6.5 to 7.7 percent. Inclusion of the older cold days would add more.

IV-3 Study the sources and uses of capacity.

To recover gas-supply costs, the Utilities must show that they incurred the costs prudently. Prudence requires maintaining the supply capacity necessary to meet the Utilities' service obligations, but not significantly more.

The Utilities have not properly examined the relationships between their service obligations to their various classes of customers, and their capacity portfolios. Liberty's analysis of winter-period capacity suggests some amount of excess capacity. The Utilities maintain that the extra capacity is required for operational reasons.[215] It is also possible that the Utilities could persuade the ICC that some excess capacity is appropriate as a reserve for possible customer or throughput growth, or for weather conditions more severe than the Design Year.[216]

The two Utilities should demonstrate that the capacity they retain is required for the provision of the services that they must provide. They should identify sources and uses of capacity for each month of the year. They should examine design weather, as well as normal weather. They should identify and examine any other special load conditions.

The Utilities should also advise the ICC of tariff changes that could have an impact on their requirements for capacity. The Utilities complained to Liberty that the Gas Bank provisions of their tariffs caused them to retain extra capacity, but then declined to provide any analysis of how much difference the provisions made.[217] The examination that Liberty recommends should include a careful assessment of the nature and amounts of capacity required to meet the Utilities' obligations to their transportation-service customers.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

IV-4 Prepare and present portfolio optimization studies.

The Utilities are currently updating their portfolio optimization analytical tools in preparation for negotiations occasioned by expiration of their Northern Border contracts. They should use those enhanced capabilities to evaluate for the ICC potential adjustments to their capacity portfolios that would increase their effectiveness for the Utilities' remaining retail customers.

Optimization studies would consider weather variation, but should also consider gas price information, both field prices and city-gate prices. The studies should also consider other factors peculiar to each Utility's service territory, including the following:

- Trends in energy utilization efficiency among their customers
- Migration from sales to transportation
- Economic growth (or contraction) among different classes of customers
- Prices of competing fuels, including at least fuel oils and electricity; perhaps also coal.

[215] Liberty telephone conference with Wirick, Marozas and Millerick, October 5, 2007.
[216] The Design Year is the weather experienced in FY1982, which saw 7,226 HDD.
[217] Response to Data Request #279.

These studies should incorporate lessons learned from the load research and forecasting improvements in Recommendation IV-1 above.

Portfolio optimization studies must also carefully isolate the operational issues associated with the load for which the capacity portfolio is being acquired, namely on-system (sales and transportation) customers. Any changes in the utilities' transportation tariffs, including their storage provisions, must be incorporated into the studies. The studies should also be conducted without any Hub activity, in order that Hub activity not interfere with optimization for on-system customers.

The recommended optimization studies will address matters that will be the subject of negotiations with pipelines and others, as the Utilities will be preparing for the expiration of the Northern Border contracts. Accordingly, the Utilities should provide the results of the studies with appropriate protections for commercially sensitive information.

The Utilities should complete the implementation of this recommendation within one year of the date of this report.

Appendix IV-A – Utilities' 25 Coldest Days' Sendout By Contract Type

PGL Winter 2006: Top 25 Coldest Days' Sendout by Contract Type (in MMBtu)

PGL Winter 2006	Sendout	Cust. Supply	Field Base	CG Base	Swing	Manlove	ANR FSS	NGPL DSS	NGPL NSS
18-Feb-06	1,488	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19-Dec-05	1,468	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18-Dec-05	1,386	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6-Dec-05	1,383	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7-Dec-05	1,363	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19-Feb-06	1,325	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20-Dec-05	1,304	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5-Dec-05	1,303	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17-Feb-06	1,278	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21-Dec-05	1,246	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17-Dec-05	1,234	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9-Dec-05	1,226	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16-Dec-05	1,192	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8-Dec-05	1,161	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4-Dec-05	1,129	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20-Feb-06	1,121	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2-Dec-05	1,094	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24-Nov-05	1,091	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1-Dec-05	1,090	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11-Dec-05	1,080	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10-Dec-05	1,076	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13-Dec-05	1,065	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16-Nov-05	1,062	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12-Dec-05	1,059	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8-Feb-06	1,052	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

PGL Winter 2005: Top 25 Coldest Days' Sendout by Contract Type (in MMBtu)

PGL Winter 2005	Sendout	Cust. Supply	Field Base	CG Base	Swing	Manlove	ANR FSS	NGPL DSS	NGPL NSS
17-Jan-05	1,579	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16-Jan-05	1,484	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24-Dec-04	1,455	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23-Dec-04	1,449	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15-Jan-05	1,432	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14-Jan-05	1,416	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22-Dec-04	1,415	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18-Jan-05	1,410	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19-Dec-04	1,364	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22-Jan-05	1,332	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27-Jan-05	1,274	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25-Dec-04	1,273	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23-Jan-05	1,263	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20-Dec-04	1,233	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

21-Jan-05	1,224	[redacted]
21-Dec-04	1,224	[redacted]
17-Feb-05	1,222	[redacted]
20-Jan-05	1,191	[redacted]
26-Dec-04	1,184	[redacted]
27-Dec-04	1,184	[redacted]
28-Jan-05	1,181	[redacted]
1-Mar-05	1,180	[redacted]
6-Jan-05	1,168	[redacted]
26-Jan-05	1,163	[redacted]
13-Dec-04	1,155	[redacted]

NSG Winter 2006: Top 25 Coldest Days' Sendout by Contract Type (in MMBtu)

NSG Winter 2006	Sendout	Cust. Supply	Field Base	Swing	Manlove	ANR FSS	NGPL DSS
18-Feb-06	302	[redacted]					
19-Dec-05	277	[redacted]					
6-Dec-05	274	[redacted]					
18-Dec-05	270	[redacted]					
17-Feb-06	265	[redacted]					
7-Dec-05	263	[redacted]					
5-Dec-05	256	[redacted]					
19-Feb-06	253	[redacted]					
20-Dec-05	242	[redacted]					
17-Dec-05	242	[redacted]					
21-Dec-05	239	[redacted]					
16-Dec-05	232	[redacted]					
9-Dec-05	230	[redacted]					
24-Nov-05	224	[redacted]					
4-Dec-05	218	[redacted]					
11-Dec-05	213	[redacted]					
8-Feb-06	213	[redacted]					
16-Nov-05	212	[redacted]					
1-Dec-05	211	[redacted]					
2-Dec-05	210	[redacted]					
8-Dec-05	210	[redacted]					
20-Feb-06	208	[redacted]					
16-Feb-06	203	[redacted]					
25-Nov-05	202	[redacted]					
12-Feb-06	201	[redacted]					

NSG Winter 2005: Top 25 Coldest Days' Sendout by Contract Type (in MMBtu)

NSG Winter 2005	Sendout	Cust. Supply	Field Base	Swing	Manlove	ANR FSS	NGPL DSS
17-Jan-05	309	[redacted]					
16-Jan-05	287	[redacted]					
14-Jan-05	281	[redacted]					
23-Dec-04	281	[redacted]					
22-Dec-04	281	[redacted]					

15-Jan-05	280	[redacted]
24-Dec-04	272	[redacted]
19-Dec-04	264	[redacted]
22-Jan-05	260	[redacted]
8-Jan-05	256	[redacted]
17-Feb-05	239	[redacted]
27-Jan-05	238	[redacted]
25-Dec-04	235	[redacted]
21-Dec-04	232	[redacted]
13-Jan-05	230	[redacted]
26-Jan-05	229	[redacted]
23-Jan-05	229	[redacted]
1-Mar-05	226	[redacted]
20-Dec-04	226	[redacted]
13-Dec-04	225	[redacted]
21-Jan-05	224	[redacted]
26-Dec-04	222	[redacted]
2-Mar-05	218	[redacted]
6-Jan-05	217	[redacted]
20-Jan-05	215	[redacted]

V. Procurement, Sales, and Portfolio Optimization

A. Introduction

1. Objectives

The RFP sought a review of the Utilities' practices and activities associated with gas supply planning, purchases, and sales. This chapter addresses the objective remaining from the planning area, and most of the objectives in purchases and sales, specifically:

- From Planning:
  - Determining how the Utilities consider reliability, flexibility, supplier diversity, and price when determining their gas supply portfolio mixtures and comparing the use of city-gate contracts versus supply obtained from retaining field zone and pipeline transportation to the city gates.
- From Purchases and Sales:
  - Determining the internal controls that ensure that ratepayers receive best purchase and sales prices
  - Determining the reasonableness of the process for deciding whether to make off-system sales
  - Determining the reasonableness of the process for deciding whether to release capacity for both transportation and storage
  - Determining how the Utilities ensure maximum credits from their leased assets (in particular, the reasonableness of the process for choosing between self-managing the assets, releasing them to a third party or allowing a third party to manage them).

Liberty's examinations in this area included:

- Evaluating the processes applied to commodity purchases
- Verifying that the Utilities have conducted purchasing cost-effectively
- Evaluating the overall approach to managing the transportation and peaking portfolios, including pipeline capacity and storage contracts, peaking facilities, and contracts (and any other commodity purchases that prove to be excessive)
- Verifying that the transactions made have been cost-effective.

2. Background

The Orders in the 2001 Reconciliation Proceedings comprehensively addressed the Utilities' Gas Purchase and Agency Agreements (GPAA) with Enron. Each Utility's GPAA with Enron covered both gas supply and the management of gas-supply assets for a five-year term beginning on October 1, 1999, (the beginning of the PEC's FY2000) and ending on October 31, 2004.

The GPAAs contained three main provisions through which Enron North America (Enron NA) provided gas supply to the Utilities:

- Baseload Quantity gas: A fixed, predetermined quantity of gas supplied every day for the duration of the contract[218]
- Summer Incremental Quantity (SIQ) gas: An additional daily amount supplied during the storage-injection season (April 1 through December 1 of each year)
- Daily Incremental Quantity (DIQ) gas: An incremental amount that supplied in addition to the other two.[219]

The three provisions disadvantaged the Utilities for the following reasons:

- Baseload Quantity: Normally priced on a monthly basis, the pricing of a portion of Peoples Gas' winter months' quantities could change to daily at Enron NA's option.
- SIQ: Enron NA could require the Utilities to take almost three times the contractual minimum under this provision. The supplier did so on 176 of the 244 days of the storage injection season that occurred during the period covered by the 2001 Reconciliation Proceeding. Over 68 percent of the days when Enron NA delivered over the minimum amount of SIQ gas, Peoples Gas was forced to sell part of the gas back to Enron NA at a penalty, because the Utility had no place to put the extra gas.
- DIQ: The structure of the contracts gave Enron NA an incentive to supply less SIQ gas and more DIQ gas when the daily gas price went above the monthly price.

The contracts also provided for the Utilities to release certain pipeline capacity to Enron NA. However, the contracts required the Utilities to reimburse Enron NA for the costs of the capacity. Previously, the Utilities used that capacity in making off-system sales. Those sales, which essentially stopped when the GPAA contracts went into effect, generated credits against the costs of the capacity. Because the Utilities' customers paid for pipeline capacity costs through the purchased-gas-cost (PGA) provision of their tariffs, but paid Enron NA a city-gate price for the gas, the ICC concluded that the Utilities' customers effectively paid for the capacity twice.[220]

The Order notes that Peoples Gas also had other gas-supply arrangements with other Enron entities, particularly Enron Midwest (Enron MW). One of the arrangements was a Storage Optimization Contract (SOC). That contract allowed Enron MW to use storage capacity under contract to Peoples Gas for various revenue-generating transactions, such as purchases and sales, and short-term storage transactions. The three-year SOC began in FY2000. Enron MW and

[218] The base-load quantities varied monthly, but the contract specified them for the duration of the contract.

[219] In comments on Liberty's draft Report, the Utilities stated

> *With respect to the DIQ, several items need to be noted. First, the right to exercise the DIQ provision was at the Companies' discretion. Second, Enron was obligated to provide DIQ on any day during the term in an amount equal to the total of firm transportation assets released to them by the Company less any baseload and SIQ scheduled on that day. This feature, the ability for the Company to nominated daily swing quantities was present in the Oneok and Occidental contracts that succeeded the GPAA, but not the onerous SIQ provision.*

[220] ICC Orders in Docket Nos. 01-0707 and 01-0706, March 28, 2006. The concern about paying twice for the pipeline capacity is expressed in the Peoples Order (Docket No. 01-0707) at p. 57.

Peoples Gas' customers shared in profits generated by such transactions, pursuant to the terms of the agreement.[221]

The Orders found all of these transactions and relationships to be imprudent. The settlements of the 2001 Reconciliation Proceedings covered not only 2001, but also 2002, 2003, and 2004. Reconciliation Dockets that examine the Utilities' gas costs for fiscal years 2005, 2006, and for October – December 2006 have been underway.

Peoples Gas and North Shore have each entered into long-term and short-term gas supply contracts with various suppliers, including [redacted] and others, with remaining gas-supply terms up to two years.[222]

B. Findings

1. The GPAA Contracts

a. Enron Bankruptcy[223]

Soon after the end of FY2001, Enron and a number of its subsidiaries filed for bankruptcy. The Utilities advised Liberty that Enron NA's performance under the GPAAs had deteriorated significantly during November 2001, and that the Utilities had given notice to initiate the process provided under the contracts for their termination. Before that process could result in termination, however, Enron filed for bankruptcy.

The Utilities' first priority at that time (December 2001) was to get their gas-supply capacity resources out of the bankruptcy proceeding, in order to assure that they would be able to use them unhindered in conducting the gas-supply activities needed to keep their customers supplied. Accordingly, the Utilities filed an emergency motion to the Bankruptcy Court seeking termination of the GPAAs. Enron objected. It was then expecting to reorganize, and wanted to keep the GPAAs (which were valuable assets) intact. Enron argued that the court should authorize it to negotiate termination payments with the various counter-parties to its contracts, and provide those payments to the bankruptcy proceeding, in lieu of the contracts themselves.

The Utilities sought to regain promptly their control over the gas-supply assets that the GPAAs had assigned to Enron NA. The Utilities agreed to suspend their emergency motion if Enron would assign those assets back to them for the duration of the suspension.[224] This result, after bankruptcy court approval, obtained for the balance of December 2001 through February 2002. The Utilities in consultation with bankruptcy counsel determined this course of action to be the

[221] Another relationship split Enron MW's profits with an affiliate of the Company.
[222] Response to Data Request #4.
[223] Interview #60, July 11, 2007, and responses to Data Requests nos. 249-255.
[224] In comments on Liberty Draft Report, the Utilities stated:

> *The loss of its largest supplier, one which was responsible to provide approximately 2/3 of it's annual supplies, was clearly a critical situation that required immediate action. The Company's only options were to go to the open market to acquire redundant assets to those that were released under the GPAA (and the extent to which such assets were available was unknown), or to somehow regain control of those same assets. The option of relying on interruptible, or spot market supplies was dismissed as unreliable and unsafe.*

promptest way to regain access to their gas-supply assets, while avoiding any liability to the Bankruptcy Court for lost value in the contracts.

During this period, Enron asked the Utilities to extend the suspension period, as it had begun to consider selling the GPAA contracts, and using the proceeds to pay creditors. The Utilities remained interested in having a third party with market expertise fulfill the functions covered by the GPAAs; therefore, they agreed to the extension. Enron then conducted a sale of the contracts. The various interested parties were generally firms with whom the Utilities had done other business. The Utilities held discussions with the various interested parties, and were able to express their views to Enron about the various parties' suitability.

OEMI won the competition for the contracts. The Bankruptcy Court approved the transaction in March 2002; the contracts resumed operation on April 1, 2002.

The transaction either terminated or transferred to OEMI all aspects of the Utilities' relationships with Enron NA and Enron MW. OEMI paid Enron's bankrupt estate $39.5 million for the GPAAs, subject to adjustment for changes in the price of natural gas between the time of contract signing and the effective date. The Utilities' parent company received $9 million from OEMI in settlement of financial instruments between Enron and various PEC entities. The Utilities' parent also received $1.3 million for the right to negotiate for Enron's one-half interest in enovate, the partnership formed by Enron MW and the Utilities' parent to conduct energy-trading activities in the Midwest U.S.[225] OEMI's performance under the GPAA contracts was supported by a parental guarantee ($15 million) and a letter of credit ($10 million).

b. The GPAAs Under OEMI

The change from Enron NA to OEMI did not otherwise change the contracts. The provisions that the ICC found problematic in the Order in the 2001 Reconciliation Proceeding remained in effect. OEMI's $39.5 million payment gave it the right to finish out the two and one-half years remaining under the contracts. The tables that follow show what happened under the three objectionable provisions after OEMI took over the contract.[226] The Monthly-to-Daily Pricing line shows the number of days in each fiscal year on which the supplier (Enron NA in FY2000, 2001; OEMI in FY2002-2004) exercised its right to convert from monthly to daily pricing. The Extra SIQ Volumes line shows the number of days in each year on which the supplier required Peoples Gas to purchase extra SIQ volumes (more than 45,000 MMBtu/day). The Sell-Back Days line shows the number of days on which Peoples Gas sold gas back to the supplier. The FY2002 entries are segregated to account for the interim period during which control of the assets returned to the Utilities.

[225] These activities included other transactions with the Utilities. See the discussion below of the Storage Optimization Contract.
[226] Response to Data Request #47. As reported in the Order in the 2001 Reconciliation Proceeding, Enron did not exercise the monthly-to-daily pricing provision. OEMI did exercise it, however. There was also an option for the Utilities to change from monthly to daily pricing, and they exercised that option during the Enron period. The table shows supplier pricing, not the Utilities' pricing elections.

GPAA Supplier Performance – PGL

Feature	FY2000	FY2001	FY2002	FY2002	FY2003	FY2004
Monthly-to-Daily Pricing	0	0	0	183	111	66
Extra SIQ Volumes	91	175	31	101	117	129
Sell-Back Days	92	170	57	4	5	19

GPAA Supplier Performance – NSG

Feature	FY2000	FY2001	FY2002	FY2002	FY2003	FY2004
Monthly-to-Daily Pricing	0	0	0	183	31	0
Extra SIQ Volumes	91	177	29	100	117	138
Sell-Back Days	50	0	0	0	0	0

2. [redacted] Contracts

Following expiration of the GPAAs in October 2004, similar contracts, with [redacted] accounted for much of Peoples Gas' supply for FY2005 and 2006.[227] The basic structure of those contracts, under which Peoples Gas assigned the capacity to the supplier in return for a discount on the city-gate price of the gas, was similar to the GPAAs. The RFP for these contracts differed from Peoples Gas' other RFPs for gas supply. It was dated June 4, 2004, and was entitled "Request for Proposal for Citygate Supply and Capacity Release by The Peoples Gas Light and Coke Company (PGL) for Multi-Year Period."

The RFP specified that Peoples Gas was seeking citygate supply consisting of both baseload and swing components, with pricing based on Chicago Citygate indices. Peoples Gas would also release certain firm transportation capacity on Northern Border and NGPL to the successful bidder, and would receive supply at the city gate. The RFP asked respondents to bid separately on providing supplies via each pipeline, and were invited to combine the bids if that could give more favorable pricing to Peoples Gas.

The RFP specified pricing for baseload and swing quantities. The RFP also discussed the release of transportation capacities, commenting on receiving credit or reimbursing supplier(s) should the rates be lower or higher, respectively. The RFP also listed extensive specific NBPL and NGPL transportation data and base-load quantities on each pipeline by month for the term of the proposed agreement.

The RFP included extensive Peoples Gas calendar year 2002 and 2003 historical information on heating degree-days, sendout, and transportation customer deliveries to aid prospective bidders. The RFP asked bidders to complete a Supplier Information Form, and to provide the usual signed Transaction Confirmation, Letter of Credit, Guaranty, and bid form.

In addition to the three provisions regarding city-gate baseload, city-gate swing, and assigning certain transportation capacities, the Transaction Confirmation made a fourth provision of the RFP clear. This feature provided for the "put" or sell-back of baseload gas when Peoples Gas had not nominated any swing gas. Peoples Gas could exercise this right for up to 50,000

[227] Response to Data Request #48, Book 9.

Dth/day, a meaningful quantity, for any 15 individual days during the put period of November 1 through March 31 for each year during the term of the contract. This put right gave operating flexibility to Peoples Gas, and, significantly, did so with no cost penalty for exercising it. The cost of the commodity to Peoples Gas and the cost credit obtained by Peoples Gas for putting this gas back were identical.[228] The GPAA contracts had required a penalty when the Utilities exercised the sell-back provision. Before including the "put option" in the [redacted] agreements, Peoples Gas was often faced with having to sell gas at a loss on surplus supply days.[229]

Liberty found the other provisions in the governing Transaction Confirmation clear and specific. For example, one important feature was to define the relationship of the swing gas to the baseload gas. Peoples Gas could nominate this additional, daily quantity over the daily baseload quantity up to the contractually agreed daily contract quantity.

Peoples Gas sent the RFP to 13 potential suppliers, 11 of whom responded with a combined 17 total or partial responses. Some contained offers expressed in different terms from those of other offers. The variances required efforts to place all offers on the same analytical basis. The documentation associated with the bid shows that Peoples Gas made appropriate, objective efforts to evaluate and consider all bids on the same basis, appropriately responded to 45 questions from bidders, and ranked the suppliers primarily by price, while also considering the suppliers' ability to perform and the assets they had to enable their performance. The low cost bidders won each part of the RFP; the NGPL part went to [redacted] and the NBPL part went to [redacted].

Peoples Gas succeeded in securing in multi-year combination contracts that avoided the disadvantageous pricing provisions of the GPAA contracts. There were, however, improvements to the RFP process that Peoples Gas could have made. Peoples Gas did not know how bidders apportioned combined costs among the four provisions in the contracts.[230] Peoples Gas did not analyze what the costs would have been to do separately what the [redacted] contracts did in a combined fashion. Any RFP that combines various aggregated deliverables should also ask for the cost bids of the disaggregated components as well as the cost bid for the aggregate. However, Peoples Gas received a sufficient number of aggregated bids from which to select low-cost, credit-qualified winners.

The following is a summary of certain results of these contracts:

- For FY2006, [redacted] aggregate cost of $9.04/Dth was driven by the fact that it was the largest supplier of more expensive winter spot gas.[231] However, [redacted] was one of the four lowest winter-spot gas suppliers among the 21 winter spot-gas suppliers.

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[228] Response to Data Request #99.

[229] Response to Data Request #140, Interview #21, February 9, 2007. In comments on Liberty's Draft Report, the Utilities stated:

The Company's actions, with respect to structuring the contracts with [redacted]*, were clearly impacted by the experience with the GPAA. Provisions that were considered negatively by Commission Staff and the ALJ were reworked to clearly be in the Company's favor.*

[230] Interview #2, January 18, 2007, Interview #18 & #19, February 7, 2007.

[231] In comments on Liberty's Draft Report, the Utilities stated

[redacted] *cost is higher because of the index plus pricing used to offset the NGPL release capacity costs at max rates. The gain on which was fully credited to our customers.*

- For FY2006, [redacted] aggregate cost of $8.31/Dth was less than the $8.44 combined average of the top five suppliers, who provided 78.6 percent of the commodity; the [redacted] aggregate cost also fell below the average of $8.52/Dth from all 26 suppliers.
- For FY2005 (for which the first month's pricing was under GPAA terms), [redacted] aggregate cost was $6.69/Dth, [redacted] was $7.06/Dth; by comparison, the average of the top five suppliers who provided 79.3 percent of the commodity was $6.83/Dth, and the average from all 24 suppliers was $6.82/Dth
- For FY2005, [redacted] winter spot gas was about [redacted] than the average winter-spot gas from 18 winter spot suppliers and about one percent cheaper than the average-summer spot gas from 16 summer spot suppliers.

These data suggest an advantage to the aggregated pricing, but do not dismiss the possibility that there could be an advantage to having disaggregated costs.

3. Other Capacity Management

a. Off-System Sales

Liberty reviewed the responsibilities and activities of off-system sales personnel.[232] Liberty also reviewed the Utilities' off-system sales philosophy, decision-making, and implementation.

The table below shows off-system sales during the audit period.[233] Off-system sales decreased to a very small level in the latter half of the audit period. The net financial impact of these sales throughout the audit period was marginal, and often negative.

Off-System Sales

PGL FY	**Million Dth Sold**	**Net $ Million**	**Net $/Dth**
1999	39.95	-1.41	-0.04
2000	29.97	1.20	0.04
2001	21.44	-0.58	-0.03
2002	41.49	-0.76	-0.02
2003	2.72	-0.02	-0.01
2004	1.90	0.32	0.17
2005	0.22	-0.21	-0.95
2006	0.26	0.08	0.31

NSG FY	**Million Dth Sold**	**Net $ Million**	**Net $/Dth**
1999		Data not available	
2000	3.44	0.17	0.05

[232] Interview #2, January 18, 2007, Interview #18&19, February 7, 2007, Interview #20, February 8, 2007, Interview #21, February 9, 2007.
[233] Response to Data Request 140. Data for Peoples Gas for FY1999 obtained from the ICC Staff.

2001	1.04	0.00	0.00
2002	0.46	0.00	0.00
2003	0.29	-0.02	-0.07
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.17	0.03	0.18

The annual quantities of commodity purchased by Peoples Gas in FY2000 through 2002, with the off-system sales netted out, were 121.5, 129.2, and 118.4 million Dth. The quantities of off-system sales for Peoples Gas were 30.0, 21.4, and 41.5 million Dth for these same years. Thus, the off-system sales ranged from about 17 to 35 percent of the net commodity purchases and averaged about 25 percent. In other words, during these years, Peoples Gas made off-system sales that equaled on average one-quarter of its net purchased commodity and lost a small amount of money doing so. In the most recent two years, off-system sales comprised less than one percent of Peoples Gas' net purchased commodity for customers.

The quantities of commodity purchased by North Shore in FY2000 through 2002, with the off-system sales netted out, were 24.3, 26.6, and 23.7 Dth. For these same years, the quantities of off-system sales for North Shore were about 3.4, 1.0, and 0.5 Dth. These off-system sales ranged from about 2 to 14 percent of the net commodity purchases and averaged about 6 to 7 percent. North Shore thus made off-system sales that averaged 6 to 7 percent of its net purchased commodity required for customers, and earned a small amount of money doing so. North Shore made no off-system sales in 2005. The 2006 off-system sales were less than one percent of its net purchased commodity for customers.

b. The Storage Optimization Contract

The Order in the 2001 Reconciliation Proceeding discusses two Peoples Gas contracts for nominated storage service (NSS) on NGPL. Peoples Gas desired 10-day and 20-day storage services to fit its customers' requirements, but the storage providers to which it had access did not offer such services. Peoples Gas' solution was to contract for conventional 75-day storages on NGPL, and then place them in optimization agreements, subject to its access when needed to serve its load.

A Peoples Gas optimization agreement was set to expire on March 31, 2000. Peoples Gas received a January 2000 offer from the incumbent operator for a new optimization agreement. Peoples Gas did not respond to that offer, but did enter the Storage Optimization Contract (SOC) with Enron MW. That three-year contract began on April 1, 2000, and provided $334,344 in revenues to Peoples Gas during the reconciliation period at issue in that proceeding (FY2001). Enron MW received a total of $717,455: $120,000 in management fees, plus its share of the profits from the optimization activity.

The SOC with Enron MW was scheduled to be in effect through March 31, 2003. Part of the disengagement from Enron in the aftermath of its bankruptcy, however, included a suspension of the SOC and then its termination effective March 31, 2002.[234] Management fees and the margin to be shared for Year 2 of the SOC (April 1, 2001 through March 31, 2002) were set to zero.

Later, during FY2003, Peoples Gas consolidated its two NSS contracts into one, with the same peak-day redelivery capacity. Peoples Gas did not attempt to create a replacement SOC, which would have continued the administration of the contracts under a third party. Instead, it chose to operate the contract(s) directly, "… for the benefit of our customers."[235]

4. Commodity Purchasing

Outside of the five-year time period encompassed by the GPAAs, the Utilities' philosophy for purchasing commodity for each utility was to use a portfolio approach, intended to diversify away from unique risks associated with gas purchases at a single location or for a single term length.[236] The tactical adaptations needed for employing this philosophy came in response to market changes caused by, for example:[237]

- New gas supply purchase options (*e.g.*, monthly to daily to intraday supply purchases)
- Different pipeline routes (*e.g.*, addition of Northern Border Pipeline providing access to Canadian supplies)
- Possible changes in regulations (*e.g.*, possible new implications in combining commodity and capacity transactions in the same agreement).

This commodity portfolio approach for each Utility sought to achieve four different types of diversity: in suppliers, geography, "layering," and time. Layering in the context of commodity purchasing means: (1) building a supply foundation on baseload gas, (2) next adding a layer of swing gas, (3) next adding a penultimate layer of call gas, and (4) finally layering in true spot-market gas. The Utilities have taken baseload gas from a given contract in the same volume daily; Gas Supply considered about 80 percent of the needed commodity quantity to comprise the baseload layer.[238] The Utilities have contracted for swing gas on a basis that allows the Utilities to select the amount of gas needed for delivery each day up to up to a daily maximum. Gas Supply secures call gas through options, which allow the Utilities to call upon it only if and as needed. The Utilities have paid premiums for two call types:

- Simple daily calls: the right to call the gas whenever desired during the option period
- Weather-contingent calls: the right to make calls when the forecast temperature at O'Hare Airport reaches a set temperature, often 10 degrees Fahrenheit.

True spot-market gas is neither optioned nor term-contracted. It is purchased when needed after all of the other layers have made their contributions to the demand need. The Utilities sometimes choose to buy spot gas before call gas, rather than use the limited quantity of call gas.

Time diversity is secured through establishing different terms for the specific contracts that comprise the commodity portfolio. Gas Supply has not operated under a formal, documented forward-looking plan that sets forth targets or objectives, but has used the general rule of seeking

[234] Response to Data Request #283.
[235] Interview No. 61.
[236] Response to Data Request #151, Interview #2, January 18, 2007, Interview #18 & #19, February 7, 2007.
[237] Response to Data Request #134.
[238] Interview #2, January 18, 2007.

an overall portfolio that exhibits a qualitatively satisfactory degree of time diversity.[239] Gas Supply has staggered term contracts to give flexibility in altering or delaying purchase decisions to adjust to changes in requirements or conditions. The field baseload contracts for the past few years have had terms ranging from one season to four years. Moreover, the city-gate baseload purchases have pricing terms that reflect both monthly and daily price components.

The supply planning process starts with an evaluation of agreements already in place. The portfolio planning models include existing contract obligations and other market and customer information. Successive model runs identify each utility's needs going forward and incorporate them into RFPs for commodity supply, where appropriate. Gas Supply purchases commodity for each of the utilities using essentially the same process.[240]

The mechanisms for purchasing commodity during the audit period included: the RFP process, bi-lateral procurement negotiations, and electronic trading platforms; *e.g.*, the Intercontinental Exchange (ICE). The RFP process, with one notable exception, applied to every term purchase during the audit period. That exception was for the Enron GPAAs. The Utilities used ICE for spot and daily purchases.[241,242]

Peoples Gas provides gas supply and capacity procurement services to North Shore pursuant to a Commission-approved service agreement.[243] The Utilities have procedures that prevent subsidy from one utility to the other, but acknowledge that inherent judgment and subjectivity make impossible an objective determination that no such subsidy has ever resulted.[244] The primary protection against inter-utility subsidization is the separate design of each Utility's portfolio. Separate designs result from considering only each Utility's own transportation contracts, storage contracts, commodity contracts, peak-day conditions, demand forecasts (seasonal, monthly and daily), and physical limitations on supply. The lack of any direct physical connection between North Shore and Peoples Gas further limits the potential for cross-subsidization. Third, Gas Supply evaluates separately each Utility's need to fill its portfolio with commodity, capacity, and storage assets. Fourth, Gas Supply sends out RFPs on behalf of each utility, often sending both simultaneously so as not to disadvantage either through RFP timing differences.

The Utilities do not have written procedures to control commodity procurement and off-system sales activities.[245] There do exist, however, process flow diagrams created as part of Gas Supply's Sarbanes-Oxley documentation.[246] Gas Supply does not perform any after-the-fact reviews, studies, or analyses to evaluate the cost-effectiveness of the supply planning process. However, the Gas Supply group indicated that it has internal conversations, goes through an annual reconciliation with the ICC, and internally shares the feedback received.[247]

[239] Response to Data Request #151.
[240] Interview #18&19, February 7, 2007.
[241] Interview #21, February 9, 2007
[242] Responses to Data Requests nos. 88, 128, and 146.
[243] Response to Data Request #80.
[244] Response to Data Request #80.
[245] Interview #2, January 18, 2007.
[246] Response to Data Request #28, Attachment C Gas Distribution SOX Flowcharts.
[247] Interview #18&19, February 7, 2007, Responses to Data Request #61 and #101.

5. Commodity Purchases

a. Summary

The next tables summarize the Utilities' commodity purchases.[248] The cost per dekatherm for the two Utilities is very close; the difference ranges from 1.4 to 5.5 percent. In all fiscal years except 2002, the Peoples Gas commodity cost per unit exceeded that of North Shore.

The commodity costs shown are without benefit of any net impact from hedging.[249] The Utilities explained that the data for fiscal years 1999 to 2002 contain net purchases minus off-system sales credits. The reason is that these data came from reports generated from the accounting system in place during those years. Data for the remaining years reflect gross purchases. The FY2003 data came from files used by accounting to create monthly journal entries; the Monaco system provided the data for the last two fiscal years.

PGL Commodity Purchases

FY	1999	2000	2001	2002	2003	2004	2005	2006
Purchases (Million Dth)	120.3	121.5	129.2	118.4	148.2	120.6	116.3	110.4
Cost (Million $)	271.0	398.0	787.9	377.0	811.3	668.5	793.2	940.2
$/Dth	2.25	3.28	6.10	3.18	5.47	5.54	6.82	8.52

NSG Commodity Purchases and Comparison to PGL

FY	1999	2000	2001	2002	2003	2004	2005	2006
Purchases (Million Dth)	23.0	24.3	26.6	23.7	27.8	25.7	24.6	24.2
Cost (Million $)	51.1	77.7	157.9	78.1	146.4	140.5	164.4	194.8
$/Dth	2.22	3.20	5.94	3.30	5.27	5.47	6.68	8.05

PGL-NSG ($/Dth)	0.03	0.08	0.16	(0.11)	0.21	0.08	0.14	0.47
PGL-NSG/PGL (%)	1.4%	2.4%	2.7%	(3.5%)	3.8%	1.4%	2.0%	5.5%

Both Utilities experienced during the audit period the increasing commodity costs characteristic of the industry. NYMEX natural gas futures prices, for example, showed significant price spikes for late calendar 2000 to early 2001, early 2003, and late 2005 (Katrina) into early 2006.[250] The general pattern in these data is similar to the price pattern shown in the tables above.

The next tables provide a more detailed view of Peoples Gas' and North Shore's commodity purchases.[251] This table includes planned and actual commodity data (noted by *P* and *A*) for each

[248] Response to Data Request #55.
[249] Responses to Data Requests nos. 133 and 136.
[250] M. Bolinger and R. Wiser, Lawrence Berkeley National Laboratory, December 2, 2006. http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf
[251] Response to Data Request #58.

fiscal year of the audit. The tables also show the total commodity sendout for: (a) traditional retail customers, (b) transportation customers, and (c) customer-owned gas for transportation customers. The difference between the total sendout and the customer-owned gas yields the sales to the traditional retail customers and the quantity of gas the utility must purchase for them. The Total Requirements line includes the small amount of additional commodity required for operating needs; *e.g.*, achieving necessary pressure in Manlove Field to extract working gas, fuel, and company-use gas.[252]

[252] Interview #18&19, February 7, 2007.

PGL Commodity Purchases, Sendout, and Costs Inclusive of Hedging

FY	1999P	1999A	2000P	2000A	2001P	2001A	2002P	2002A	2003P	2003A	2004P	2004A	2005P	2005A	2006P	2006A
Total Sendout (Million Dth)	239.9	211.6	230.3	204.4	225.9	221.5	217.4	196.8	216.9	218.2	210.3	196.0	204.8	185.3	194.9	177.1
Total Requirements (Million Dth)	240.5	214.7	230.7	205.4	226.3	222.5	217.8	198.1	217.3	219.2	211.0	197.2	206.2	189.8	196.8	179.6
Customer-Owned Gas (Million Dth)	102.9	95.5	95.5	86.7	105.3	88.6	94.5	80.2	88.4	83.0	84.4	78.0	80.5	73.2	74.1	71.8
Total Purchases (Million Dth)	134.4	119.8	134.3	121.1	121.0	132.0	123.2	116.9	128.9	145.8	126.6	119.0	125.7	116.3	122.6	110.3
Implied Purchases (Million Dth)	137.0	116.1	134.8	117.7	120.6	132.9	122.9	116.6	128.5	135.2	125.9	118.0	124.3	112.1	120.8	105.3
Cost (million $)	301.7	274.9	385.3	413.3	620.6	791.3	528.3	379.2	446.6	685.9	632.9	649.1	827.1	785.4	992.9	974.2
Cost ($/Dth)	2.24	2.28	2.87	3.41	5.13	6.12	4.23	3.20	3.46	4.70	5.00	5.45	6.58	6.75	8.10	8.83

NSG Commodity Purchases, Sendout, and Costs Inclusive of Hedging

FY	1999P	1999A	2000P	2000A	2001P	2001A	2002P	2002A	2003P	2003A	2004P	2004A	2005P	2005A	2006P	2006A
Total Sendout	39.7	34.7	39.5	34.5	38.4	36.6	35.9	34.2	37.3	39.2	39.4	37.4	39.9	36.5	37.9	35.2
Total Requirements	39.9	35.1	39.7	34.9	38.6	36.9	36.1	34.7	37.5	39.6	39.7	37.9	40.2	37.3	38.2	36.0
Customer Gas	13.0	12.0	13.0	11.4	12.1	10.3	11.1	11.0	13.0	11.5	14.6	13.1	13.9	12.5	12.4	12.8
Total Purchases	26.9	22.5	26.7	23.5	26.5	26.6	25.1	23.7	24.5	28.0	25.5	25.7	26.3	24.6	25.8	24.1
Implied Purchases	26.7	22.7	26.5	23.1	26.3	26.3	24.8	23.2	24.3	27.7	24.8	24.3	26.0	24.0	25.5	22.4
Cost (million $)	61.4	53.0	76.5	78.4	135.7	160.4	105.8	80.0	84.5	126.0	141.7	142.5	171.4	165.6	207.8	202.2
Cost ($/Dth)	2.28	2.27	2.86	3.23	5.12	6.02	4.22	3.38	3.45	4.50	5.56	5.53	6.52	6.72	8.05	8.40

PGL-NSG ($/Dth)	-0.04	0.01	0.01	0.18	0.01	0.10	0.01	-0.18	0.01	0.20	-0.56	-0.08	0.06	0.03	0.05	0.43
(PGL-NSG)/PGL (%)	-1.8%	0.4%	0.3%	5.3%	0.2%	1.6%	0.2%	-5.6%	0.3%	4.3%	-11.2%	-1.5%	0.9%	0.4%	0.6%	4.9%

The planned quantities are typically greater than the actual quantities for sendout, total requirements, and customer-owned gas. Planned purchase quantities exceeded actual amounts for all years by about five to ten percent except for fiscal years 2001 and 2003, when the actual purchases were greater than plan by about 9 and 13 percent, respectively. Fiscal years 2001 and 2003 were colder than plan by about 4 percent whereas the other years were warmer than plan by nine to thirteen percent, except for fiscal year 2004, which was about five percent warmer than plan.[253]

The Implied Purchases line tests whether the relationship between actual total sendout (to traditional rate customers and transportation customers), purchases, and customer-owned gas in this data source is reasonable from the perspective of procuring commodity.[254] Subtracting actual customer-owned gas from actual sendout and comparing that result net of Implied Purchases for retail sales with the total actual purchases agrees within an average 2.5 percent over the audit period. Three of the years are identical, three agree to within about 3 percent, 2006 totals agree to within about 4.5 percent; 2003 exhibits a wider margin of 7 percent.

The planned quantities for North Shore typically exceeded the actual quantities for sendout, total requirements, and customer-owned gas. For purchases, the planned quantities were greater than actual for five of the audit years by about 6 to 16 percent, virtually identical for fiscal years 2001 and 2004, and greater than plan by about 14 percent for fiscal year 2003 (which was colder than plan).

The Implied Purchase line agrees within 1 or 2 percent of the total actual purchases for six of the audit years is within 5 percent for FY2004 and is within about 7 percent for FY2005.

The tables show that the actual hedge-impacted commodity cost in dollars-per-dekatherm between the Utilities over the audit period was very close. The actual costs between the two utilities were virtually identical for two years, Peoples Gas' costs were more by about 2 to 5 percent for four years, and North Shore's costs were more by 5.6 percent in FY2002 and by 1.5 percent in FY2004.

b. Layering

Liberty examined a breakdown of the various layers of commodity procurement.[255] For the last three fiscal years in the audit period, the purchase segmentation among baseload, winter spot, summer spot, and call gas was available. For the previous years, the Utilities said that this segmentation was not available.

[253] Response to Data Request #84.
[254] Response to Data Request #58.
[255] Response to Data Request #55.

PGL

Fiscal Year	2004	2005	2006
Purchases (Million Dth)	120.6	116.3	110.4
Cost (Million $)	668.5	793.2	940.2
$/Dth	5.54	6.82	8.52

Baseload (Million Dth)	79.4	99.3	93.0
% of Total Dth (%)	65.8	85.3	84.2
% of Cost (%)	65.5	85.7	81.6
$Cost/Dth ($/Dth)	5.51	6.85	8.25

Winter Spot (Million Dth)	8.2	6.1	7.5
% of Total Dth (%)	6.8	5.3	6.8
% of Cost (%)	6.1	4.9	9.0
$Cost/Dth ($/Dth)	4.93	6.30	11.39

Summer Spot (Million Dth)	30.5	9.1	7.8
% of Total Dth (%)	25.3	7.8	7.1
% of Cost (%)	26.4	7.8	6.3
$Cost/Dth ($/Dth)	5.78	6.86	7.62

Call Gas (Million Dth)	2.5	1.9	2.1
% of Total Dth (%)	2.0	1.6	1.9
% of Cost (%)	2.1	1.6	3.0
$Cost/Dth ($/Dth)	[redacted]	[redacted]	[redacted]

In the above table, the baseload layer for fiscal years 2006 and 2005 is the summation of field baseload, city base load, and summer fill. For FY2004, it is the baseload from the GPAA contract plus summer fill.[256] This baseload commodity quantity ranged from about 66 to 85 percent of the total commodity purchased.

Winter spot gas for FY2005 and FY2006 is the city-gate swing gas from the [redacted] and [redacted] gas-supply and asset-management contracts that essentially replaced the GPAA contract when it concluded October 31, 2004.[257] For FY2004, the winter spot gas is spot gas for the service described as Title Transfer Point (TTP). Winter spot gas ranged from about 5 to 7 percent of the total commodity purchased. Summer spot gas was about 7 percent of total commodity purchased for the last two audit years and about 25 percent for FY2004. Call gas for FY2004-2006 was the daily and weather calls, and was about 2 percent of total commodity purchased.

[256] Response to Data Request #58.
[257] Response to Data Request #47.

Even though categorization of these procurement layers was not rigorous for the three years for which the data was available, the pattern is clear: baseload gas was the major layer by far, ranging from about 66 to 85 percent, followed by the seasonal spot/swing gas, with the call gas being about 2 percent.

The next table shows similar data for North Shore.

NSG

FY	2004	2005	2006
Purchases (Million Dth)	25.7	24.6	24.2
Cost (Million $)	140.5	164.4	194.8
$/Dth	5.47	6.68	8.05
Baseload (Million Dth)	18.2	22.9	22.2
% of Total Dth (%)	70.6	92.8	91.7
% of Cost (%)	69.8	93.2	87.0
$Cost/Dth ($/Dth)	5.4	6.7	7.6
Winter Spot (Million Dth)	0.4	0.4	0.5
% of Total Dth (%)	1.4	1.6	1.9
% of Cost (%)	1.3	1.6	3.0
$Cost/Dth ($/Dth)	5.0	6.5	12.6
Summer Spot (Million Dth)	5.5	1.0	0.5
% of Total Dth (%)	21.4	4.2	2.1
% of Cost (%)	22.4	3.9	3.1
$Cost/Dth ($/Dth)	5.7	6.1	11.7
Call Gas (Million Dth)	1.7	0.4	1.0
% of Total Dth (%)	6.6	1.4	4.3
% of Cost (%)	6.5	1.4	6.9
$Cost/Dth ($/Dth)	[redacted]	[redacted]	[redacted]

Winter spot gas for the three years was about 2 percent of the total purchased commodity, which is less than but similar to the corresponding Peoples Gas amount. Summer spot averaged about 3 percent of the total purchased commodity in FY2005 and 2006, and was 21 percent in 2004, which is similar to the pattern for Peoples Gas.

Call gas for the three years consists of the daily and weather calls. It averaged about 3 percent for FY2005 and 2006, and was about 6 percent for FY2004. The corresponding levels of call gas are smaller than those of Peoples Gas. North Shore did not have an optimization contract after

GPAA contracts expiration; rather, it relied on baseload, summer storage fill, and spot gas.[258] The base-load layer for North Shore was the overwhelming component for commodity supply, ranging from about 70 to 93 percent.

c. Term Lengths

For FY2005 and 2006, the field baseload-gas contracts for Peoples Gas were split about equally between two- and four-year terms, and the city baseload and city swing gas were for two-and-a-half years.[259] Baseload gas for North Shore for these FYs was about equally divided between four-year terms and the combined two-and three-year term contracts. For both utilities, the summer fill during this period consisted of a six-month term of May through October. For both utilities, winter call gas was typically contracted for three-month terms of December through February.

For FY2000 through 2004, the time period during which the GPAA contracts provided the dominant source of supply, the contract terms for baseload gas and other gas layers that were typically active during the winter or summer periods was for five years for both utilities. Term commodity purchases outside of the GPAA contract were typically for one or two years, or were seasonal.[260]

During FY1999[261], baseload gas for Peoples Gas was about equally divided among one-year, two-year, and some remaining six-to ten-year contracts. For North Shore during FY1999, the term for baseload gas was about one-third two-year, one-third five-year, one-quarter one-year, and the remainder three-year. During this early audit year, winter gas was taken under one- to three-year term contracts for North Shore, even though it was contracted to be taken only from December through March of each year, and typically under a one-year contract for Peoples Gas.

d. Commodity Procurement Mechanisms

In FY2006, Peoples Gas procured 91.5 percent of its commodity through an RFP process, whose procurements accounted for 89.2 percent of the total dollars spent.[262] For North Shore for FY2006, these RFP percentages were 91.3 of volume and 91.7 percent of cost. For FY2005, the Peoples Gas RFP percentages and the associated dollar percentages were 95.5 and 92.9 percent. The corresponding FY2005 amounts for North Shore were 91.1 and 91.3 percent.

For the five years of 2000 through 2004, the GPAA contracts provided an average of 73 percent of the commodity supply for Peoples Gas and 66 percent for North Shore.[263] The Utilities used the RFP process to procure the remaining commodity that was not spot gas.[264]

The Utilities said that no detailed hard-copy procurement process data for FY1999 was available.[265] However, a number of indicators (indirect evidence from contract summaries,[266]

[258] Interview #18&19, February 7, 2007.
[259] Response to Data Request #48.
[260] Response to Data Request #149.
[261] Response to Data Request nos. 46, 146.
[262] Responses to Data Requests nos. 88 and 55.
[263] Response to Data Request #55.
[264] Response to Data Request #48.
[265] Response to Data Request #150.

procurement quantity and supplier data,[267] interview commentary,[268] and confirmation[269] that the GPAA was the only significant commodity supply contract solicited bilaterally) suggest that an RFP process was used for all other commodity procured by both utilities for FY1999 outside of spot gas.

Gas Supply maintains a list of potential suppliers in the form of a list of those counterparties with whom Peoples Gas[270] and North Shore[271] have master contracts. One of the more recent lists for each shows 26 suppliers for Peoples Gas and 23 for North Shore.

The process that was used for RFP solicitations included:

- Assessing the current portfolio to determine needs going forward
- Assessing the market for available counter-parties, products, services
- Deciding whether to address needs through an RFP process and document decision
- Reviewing potential suppliers to determine RFP recipients, and striving to maximize the number to receive the RFP to achieve a satisfactory number of bid responses
- Specifying criteria of price, location of supply, delivery point, bidder's creditworthiness, past performance, access to supply at diverse locations, firm transportation, quantity of supply, nomination deadline, daily take flexibility, any special terms and other pertinent factors such as supplier diversity
- Consulting the Corporate Credit department to vet the RFP candidates
- Issuing the RFP complete with e-mail address for bid submittal.

The handling and review of the RFP bids received included:

- Designating an e-mail account that can be accessed only after the bid deadline by the Gas Supply personnel responsible for opening the bids; Corporate Internal Audit has the option to participate in the bid opening.
- Designating a Gas Supply team to review all responsive bids.
- Documenting bids received and time.
- Specifying Gas Supply's allocation between Peoples Gas and North Shore when bidders combined the requirements of both Utilities.
- Summarizing the bid responses onto a spreadsheet incorporating the above criteria, and meeting to make recommendations.
- Compiling an RFP Review Package that included the RFP, the bids, the review spreadsheet, and the recommendations, along with explanations and analyses.

The acceptance of RFP bids included:

- Reviewing by appropriate authority level
- Documenting reasons for selecting the winning bid(s)

[266] Response to Data Request #46.
[267] Response to Data Request #55.
[268] Interview #18&19, February 7, 2007, Interview #21, February 9, 2007.
[269] Response to Data Request #128.
[270] Response to Data Request #17.
[271] Response to Data Request #127.

- Communicating decision(s) to all bidders, and finalizing detailed paperwork for the winners that includes obtaining internal signoffs from Gas Supply, Contract Administration, Corporate Credit and Legal in order to execute the Transaction Confirmations already signed by the bidders (master contracts were already in place) plus distributing documents internally for control and operating purposes.

Liberty reviewed 25 large, three-ring binders of hard-copy paper trail for RFP commodity procurement for FY2000 through 2006. [272] Liberty found that the documentation, analyses, and decision-making process followed the expected process steps for FY2003 through 2006. Typically, about 10 to 20 counter-parties would simultaneously receive an RFP package for Peoples Gas and for North Shore so that neither utility would be potentially time-disadvantaged. Respondents often submitted multiple bids containing different specifics. Bids were opened and evaluated as described. Usually, cost was the primary determinant among reliable suppliers for selecting the winners in a price-ordered fashion. Occasionally supply diversity played a minor role. Occasionally, there would be an insufficient number of respondents to enable Gas Supply to feel comfortable in subscribing all of their commodity needs at a particular location for a term contract. In that event, they would handle the unsubscribed quantity on a month-to-month spot basis.

e. Supplier Qualification

All counter-parties, whether a seller to or a buyer from one of the Utilities, were to undergo the same credit or risk scrutiny before becoming a counter-party and maintaining that qualification. The Utilities applied appropriate physical performance considerations.[273] Financial aspects control the credit risk qualification, and reliability of performance dominates the physical performance considerations. Gas Supply or operating personnel evaluated physical performance on a case-by-case basis.[274] Gas Supply's policy was not to contract again with counter-parties who did not perform. Gas Supply maintained master agreements with suppliers meeting their financial and physical performance needs.

f. Supplemental Purchases during the Enron Period

Liberty's examination of the supplemental procurement data for FY2000 through 2002 revealed the following:[275]

- The process and decision patterns for the RFP process that were evident and clear in the FY2003 through 2006; there was supporting data in the FY2000-2002 period, but it was not as complete.
- No Transaction Confirmation was required to be submitted as part of the bid in response to the RFP. This appeared to cause additional negotiations between the original bid and the final agreement.
- The strategy of sending RFPs to about the same number of potential suppliers, typically ten to twenty, as was done in the later audit years was evident.
- Numerous responses were received, with suppliers often offering several bids.

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[272] Response to Data Request #48 and Response to Data Request #48, Supplemental.
[273] Interview #22, February 8, 2007.
[274] Interview #2, January 18, 2007, Interview #18 & #19, February 7, 2007, Interview #21, February 9, 2007.
[275] Response to Data Request 48 Supplemental.

- Winners were selected primarily on price, with reliability being an important consideration. In the case of certain call gas, late or intra-day nominations were very important.
- Price was documented, but reliability documentation was not as clear.
- The strategy of procuring layers of commodity was clearly evident.
- RFP letters sent in FY1999 for gas to flow in FY2000 combined Peoples Gas and North Shore requirements. In FY2000 and later, the RFP letters were individual for each utility.

The RFP process used in FY2000 through 2002 took place under the same overall approach and methods that applied from FY2003 through 2006. The RFP paper trail shows the RFP process to have been implemented more effectively beginning in FY2003, however. Inclusion of the Transaction Confirmation along with additional credit-related requirements as part of the bids made for a more efficient process. The rather robust RFP process used early in the audit period for term commodity highlighted how atypical was the bilateral, non-RFP process used for the GPAA contract.

g. Diversity of Supply Sources and Pricing Mechanisms

i. The GPAA

The GPAA provided much of the supply for five of the eight audit-period years. The pricing for each layer for Peoples Gas was as follows:

- BQ: Chicago First of Month (FOM) index minus 3¢, except when subject to Baseload Price Adjustment
- SIQ: Chicago FOM index minus 3¢
- DIQ: Daily price.

The agreement also included a provision to sell back to Enron NA the commodity that Peoples Gas had purchased. The pricing provision for day-before commodity sell-back by Peoples Gas to Enron was:

- Daily price less 1¢ for the first 50,000 Dth/day
- Daily price less 2¢ for the second 50,000 Dth/day
- Daily price less 3¢ for the third 50,000 Dth/day.

For day-of sell-back, an additional half cent/Dth was charged for each tier.

Finally, the GPAA limited commodity quantities to the capacity Peoples Gas released to Enron NA, plus the capacity that Peoples Gas had Enron acquire on its behalf.[276]

The GPAA contract with North Shore was similar to that for Peoples Gas, with two exceptions. First, it contained only the Flexible Pricing provision, but not the Baseload Price Adjustment. Second, it covered smaller quantities. The pricing for each layer for North Shore was as follows:

- BQ: Chicago First of Month (FOM) index minus 2¢
- SIQ: Chicago FOM index minus 2¢
- DIQ: Daily price.

[276] Response to Data Request #149.

The pricing provision for commodity sell-back by North Shore to Enron NA on the day before was:

- Daily price less 1¢ for 0 to 25,000 Dth/day for FY2000
- Daily price less 1¢ for 0 to 10,000 Dth/day for rest of contract.

For sell-back on the day of, an additional half cent/Dth was charged.

As with Peoples Gas', North Shore's GPAA contract limited commodity quantities to the capacity North Shore released to it, plus the capacity North Shore had Enron acquire on its behalf.[277]

Commodity purchased by either Utility outside of the GPAA contracts during this period was priced typically at FOM for term gas and daily for spot gas.[278] These purchases would involve straightforward purchases and pricing mechanisms without 'full service' contract provisions, and would contain any typical basis cost adjustment to compensate for any basis differential between the quoted pricing and delivery points.

During this period, both Utilities paid demand option fees for daily or weather call gas that they felt might be needed beyond any non-baseload or additional gas contained in the term contracts, should the weather be colder than plan.[279] If the weather was warmer than plan and the call gas was not needed, they would have paid the demand cost for the options, but not the full cost of the commodity. If the weather was colder than plan and the call gas was needed, the utilities then paid the full cost of the commodity (in addition to having already paid the demand cost) at a daily price for commodity they knew would be available to them.

ii. Pricing Mechanism for Remaining Audit Years

For FY2005 and 2006, with the exception of October 2004 that was still under the GPAA terms, the standard pricing mechanisms for both Utilities were first-of–the-month (FOM) index pricing for monthly or longer term gas (*e.g.*, baseload or summer-fill gas) and daily pricing for spot gas (*e.g.*, call gas and swing gas).

The combination contracts with [redacted] and [redacted] that replaced the GPAA contracts for Peoples Gas were also 'full service' contracts in that they provided for baseload gas, swing or short term gas, utilization of Peoples Gas' already contracted capacity, and the opportunity to sell back commodity not needed.[280] However, these new combination contracts did not have the onerous pricing provisions of the GPAA contracts (*e.g.* Baseload Price Adjustment, Flexible Pricing for converting FOM to daily pricing for the winter period, and a sell-back price inferior to the purchase price). For these new contracts, the sell-back price for excess commodity was identical with the purchase price.[281]

[277] Response to Data Request #149.
[278] Responses to Data Requests nos. 46 and 48.
[279] Response to Data Request #46.
[280] Response to Data Request #48.
[281] Response to Data Request #99.

Commodity purchased by either utility that was not part of the term contracts for this period was priced at either FOM if term gas or daily if spot gas, and would contain basis differentials, if appropriate.[282] During this period, both Utilities paid option demand fees for daily or weather call gas.[283]

iii. Supplier Diversity

The table below shows the top five suppliers for Peoples Gas for the audit period.[284]

PGL Top Suppliers for FY2006 through 2004

FY2006 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	21.8	16.6	0.6	4.6		8.31
[redacted]	19.8	16.1	1.7	1.6		9.04
[redacted]	16.6	16.4	0.2	0		7.84
[redacted]	12.1	9.8	1.0	0.1	1.1	8.67
[redacted]	8.3	7.0	1.0	0.3		8.23
Subtotal	78.6	66.4	4.5	6.6	1.1	8.44

FY2005 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	23.5	18.8	0.7	4.0		6.69
[redacted]	19.0	15.0	1.9	2.0	0.0	7.06
[redacted]	14.8	14.4	0.2	0.2		6.82
[redacted]	11.5	9.9	0.8	0.5	0.2	6.97
[redacted]	10.5	9.2	0.5	0.3	0.6	6.58
Subtotal	79.3	67.3	4.1	7.0	0.8	6.83

FY2004 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	75.9	48.6	4.0	23.2	0.2	5.59
[redacted]	6.3	6.3				5.80
[redacted]	3.6	3.1	0.2	0.1	0.3	5.41
[redacted]	2.3	2.1	0.1	0.1		5.73
[redacted]	1.8	1.4	0.3	0.1		5.44
Subtotal	90.0	61.5	4.6	23.5	0.5	5.60

[282] Responses to Data Requests nos.46 and 48.
[283] Response to Data Request #46.
[284] Response to Data Request #55.

The top five FY2006 suppliers provided 78.6 percent of the commodity purchased by Peoples Gas. The top ten suppliers provided almost 95 percent. The average cost for the top five suppliers was $8.44/Dth, compared with $8.52/Dth average for all suppliers. Thus, the fact that the top five supplied such a large portion of the total did not appear to have disadvantaged the Utility. The top five FY2005 suppliers provided 79.3 percent of the commodity purchased by Peoples Gas. The top ten suppliers provided almost 96 percent. The average cost for the top five suppliers was $6.83/Dth, compared with $6.82/Dth average for all suppliers.

OEMI supplied almost 76 percent of the total 2004 commodity purchased by Peoples Gas. The cost of commodity from OEMI was the median of the cost from the top five suppliers. Outside of the top five suppliers, 19 of the remaining 21 provided gas cheaper than did OEMI. The average costs for these other suppliers were $5.06/Dth compared with the total average cost of $5.54/Dth for all of the suppliers. This average is heavily weighted by OEMI's cost of $5.59/Dth. Peoples Gas may well have obtained improved commodity costs had not almost 76 percent of its supply been from one supplier, and had the contract not contained the onerous pricing mechanism provisions of Baseload Price Adjustment, Flexible Pricing, and inferior sell-back prices. The top five suppliers provided 90 percent, and the top ten suppliers provided almost 96 percent of Peoples Gas' requirements during the period that the GPAA was in effect.

The following table shows the total commodity provided by the top suppliers for the remainder of the audit period. These data were not available with a breakout into layers.[285]

[285] Response to Data Request #55.

PGL Top Suppliers for FY2003 through 1999

	% of Total	Cost $/Dth
FY2003		
[redacted]	67.1	5.42
[redacted]	4.8	5.56
[redacted]	3.9	6.76
[redacted]	3.7	5.3
[redacted]	2.8	5.74
Subtotal	82.3	5.5
FY2002		
[redacted]	32.9	3.58
[redacted]	12.9	2.24
[redacted]	12.5	3.63
[redacted]	9	3.23
[redacted]	5.9	2.62
Subtotal	73.2	3.23
FY2001		
[redacted]	68.4	5.89
[redacted]	8.7	7.25
[redacted]	3.1	4.59
[redacted]	2.5	4.69
[redacted]	2.3	4.95
Subtotal	85.1	5.92
FY2000		
[redacted]	84.9	3.18
[redacted]	2.5	3.81
[redacted]	2.2	3.54
[redacted]	1.8	3.67
[redacted]	1.8	3.93
Subtotal	93.2	3.23
FY1999		
[redacted]	8.4	2.42
[redacted]	8.2	2.23
[redacted]	6.9	2.15
[redacted]	6.2	2.36
[redacted]	6	2.29
Subtotal	35.7	2.29

OEMI supplied the lion's share at 67.1 percent of the FY2003 commodity for Peoples Gas, which took supply from 30 counterparties. The top five suppliers provided 82.3 percent and the top ten provided almost 92 percent. OEMI's cost was $5.42/Dth and the average cost from the top five was $5.50. The average cost for the remaining 25 suppliers was lower, at $5.34/Dth. Similar to FY2004, this differential suggests that Peoples Gas may well have obtained improved commodity costs had not two-thirds of its supply been from one supplier and subject to the GPAA's onerous pricing provisions.

OEMI provided 32.9 percent of the FY2002 commodity for Peoples Gas and was among 38 suppliers. During FY2002, the utility had to take expeditious efforts to supply itself for four months after the Enron bankruptcy. The greater number of suppliers appears in this year reflects that situation. The top five suppliers provided 73.2 percent and the top ten (not shown) provided slightly less than 85 percent. OEMI's costs again were relatively high ($3.58/Dth). The average cost for the top five was $3.23. The average cost for the remaining 33 suppliers was $2.96, with the average cost for all suppliers being $3.18.

Enron NA and Enron Midwest largely under the GPAA contract together provided 77.1 percent of the FY2001 commodity for Peoples Gas and were among 32 suppliers. The top five supplied 85.1 percent and the top ten (not shown) provided about 93 percent. The commodity cost from both Enron entities was the highest among the top five suppliers, whose average cost was $5.92/Dth, while the average for all suppliers was $6.10. Since the average cost from the 27 suppliers outside of the top five was greater at $7.32/Dth, it does not appear that greater quantity procured from these minor suppliers would have reduced costs to Peoples Gas. However, the question remains whether more quantities could have been procured from [redacted], whose collective cost was about $4.75/Dth.[286]

Enron NA provided 84.9 percent of the FY2000 commodity to Peoples Gas under its GPAA contract and was among 30 suppliers. The top five supplied 93.2 percent and the top ten (not shown) provided just over 97 percent. The commodity cost from Enron at $3.18/Dth was the lowest among the top five who averaged $3.23/Dth. The remaining 25 minor suppliers averaged a greater cost at $3.61, and the average cost from all suppliers was $3.28/Dth. For this year, it does not appear that Peoples Gas was disadvantaged by the large GPAA contract.

The top five FY1999 suppliers provided only 35.7 percent of the commodity Peoples Gas purchased, and the top ten (not shown) provided about 62.5 percent. There were fifty suppliers to Peoples Gas at an average cost of $2.25/Dth. The average cost for the top five suppliers was $2.29/Dth, the average cost for the remaining 45 suppliers was $2.21/Dth, and the average cost for all suppliers was $2.25/Dth. These costs are very close to each other, and indicative of purchasing competitively from many sources.

Petitions currently before the U. S. Federal Energy Regulatory Commission (FERC) ask for clarification of how the FERC views contracts that combine capacity with commodity.[287]

[286] In comments on Liberty's Draft Report, the Utilities stated

> *The vast majority of the referenced purchases were field purchases made in the summer for storage refill and are not representative of a good sampling with which to make this comparison.*

[287] Response to Data Request #134.

Uncertainty with how the FERC will rule, coupled with severe penalties for violating a FERC regulation, has convinced Gas Supply not to enter into another large combination agreement like the [redacted] and [redacted] contracts that expired in April 2007.[288]

The next tables show the top five suppliers for North Shore for the audit period.[289]

NSG Top Suppliers for FY2006 through 2004

FY2006 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	59.1	57.8	0.2	0.4	0.6	7.59
[redacted]	17.4	15.0		0.3	2.2	8.73
[redacted]	16.1	14.8	0.9	0.4		8.17
[redacted]	4.3	3.3			0.9	7.64
[redacted]	0.9		0.4	0.5		12.68
Subtotal	97.8	91.0	1.5	1.6	3.7	7.94

FY2005 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	57.5	54.5	0.1	3.0		6.58
[redacted]	18.1	16.3	0.8	1.0		6.89
[redacted]	15.5	14.8			0.7	6.93
[redacted]	4.1	3.9	0.2			6.93
[redacted]	0.8	0.8				4.80
Subtotal	95.9	90.3	1.1	4.0	0.7	6.70

FY2004 Suppliers	% of Total	% as Base	% as Winter Spot	% as Summer Spot	% as Call	Cost $/Dth
[redacted]	65.8	43.7	1.1	19.4	1.6	5.54
[redacted]	6.4	4.4	0.2	0.5	1.3	5.25
[redacted]	5.3	5.0			0.2	4.92
[redacted]	4.9	3.0		0.7	1.2	5.68
[redacted]	4.4	4.4				5.57
Subtotal	86.7	60.5	1.3	20.6	4.3	5.49

[redacted] supplied 59.1 percent of the FY2006 commodity purchased by North Shore from among 13 suppliers. The top five suppliers provided 97.8 percent, of which 91 percent was for baseload gas. [redacted] was the low-cost supplier among the top five that averaged $7.94/Dth. The remaining eight suppliers had an average cost of $12.40/Dth, and the average of all suppliers was

[288] Interview #20, February 8, 2007.
[289] Responses to Data Request nos. 55 and 143 for corrected FY2005 data for North Shore.

$8.04/Dth. North Shore purchased primarily baseload gas and does not appear to have been disadvantaged for this year by securing most of its baseload from the low-cost supplier.

[redacted] supplied 57.5 percent of the FY2005 commodity purchased by North Shore from among 15 suppliers. The top five provided 95.9 percent, of which about 90 percent was for baseload gas. [redacted] was the low-cost supplier at $6.58/Dth from among the major three large suppliers, was lower in cost than the $6.70/Dth average of the top five suppliers, and lower in cost than the average $6.67/Dth of all of the suppliers. [redacted] was more expensive than the average $6.12/Dth cost from the remaining ten suppliers, who supplied only 4.1 percent of the commodity. Most of this remaining gas was summer fill that was comparatively less expensive. Commodity is frequently less expensive in the summer. North Shore did not appear to have been disadvantaged by securing most of its baseload from one of the lower-cost suppliers, but the patterns here reinforce the suggestion that assessment of cost patterns among the layers may be useful in procurement analyses and structuring the procurement. The first month of this fiscal year, October 2004, was under GPAA pricing.

OEMI supplied 65.8 percent of the FY2004 commodity purchased by North Shore from among 13 suppliers. As with Peoples Gas, this fiscal year is part of the period covered by the GPAA contract. The top five FY2004 suppliers provided 86.7 percent of the commodity for North Shore. OEMI, at $5.54/Dth, was the median-cost supplier among the top five (who averaged $5.49/Dth), was more expensive than the $5.30/Dth average of the remaining eight suppliers, and was more expensive than the $5.46/Dth average for all of the suppliers. North Shore may well have obtained improved commodity costs had not almost 66 percent of its supply been from one supplier, with some onerous pricing mechanisms of Flexible Pricing and inferior sell-back prices. The spread among these various costs is within five percent, however.

NSG Top Suppliers for FY2003 through 1999

FY2003	% of Total	Cost $/Dth
[redacted]	62.9	5.33
[redacted]	9.3	5.08
[redacted]	4.4	4.64
[redacted]	3.6	6.58
[redacted]	3.5	6.21
Subtotal	83.8	5.35
FY2002		
[redacted]	32.9	3.64
[redacted]	11.8	3.86
[redacted]	10	2.73
[redacted]	5.4	2.59
[redacted]	4.8	1.94
Subtotal	64.8	3.32
FY2001		
[redacted]	66.4	5.54
[redacted]	5.6	7.75
[redacted]	4.7	4.94
[redacted]	4.5	4.92
[redacted]	3.6	8.65
Subtotal	84.7	5.75
FY2000		
[redacted]	87.9	3.13
[redacted]	4.1	3.78
[redacted]	3.3	3.88
[redacted]	1.2	3.47
[redacted]	0.8	3.82
Subtotal	97.3	3.19
FY1999		
[redacted]	52.8	2.18
[redacted]	7.6	2.45
[redacted]	7.6	2.66
[redacted]	7.4	2.29
[redacted]	4.1	2.24
Subtotal	79.4	2.27

OEMI supplied 62.9 percent of the FY2003 commodity purchased by North Shore from among 17 suppliers. The top five suppliers provided 83.8 percent of the commodity for North Shore. OEMI (at $5.33/Dth) was the median-cost supplier among the top five that averaged $5.35/Dth, was more expensive than the $4.76/Dth average cost of the remaining twelve suppliers, and was more expensive that the $5.26/Dth average for all of the suppliers. North Shore may well have obtained improved commodity costs had not almost 63 percent of its supply been from one supplier with some onerous pricing mechanisms. Unlike FY2004, the cost spread between OEMI and the remaining twelve suppliers averaged about 11 percent, however.

OEMI supplied 32.9 percent and Enron NA 11.8 percent of the FY2002 commodity purchased by North Shore from among 28 suppliers. FY2002 was the year the Utility had to supply itself for three months after the Enron bankruptcy. The combined 44.7 percent commodity supply from OEMI and Enron NA came under the same contract.[290] This 44.7 percent is a notably smaller percentage of supply from one supplier than for the other audit years. Nevertheless, Enron NA was the most expensive supplier at $3.86/Dth, and OEMI the second most expensive at $3.64/Dth, from among the top five suppliers who averaged $3.32/Dth and who supplied about 65 percent of the commodity to North Shore. The average cost from the remaining 23 suppliers was $3.12/Dth, and the average cost from all suppliers was $3.30/Dth. As was the case with FY2003 and 2004, North Shore may well have obtained improved commodity costs had not almost 45 percent of its supply been from OEMI and Enron under identical contract terms.

Enron NA supplied 66.4 percent of the FY2001 commodity purchased by North Shore from among 17 suppliers. Enron NA at $5.54/Dth was the median-cost supplier among the top five that averaged $5.75/Dth and supplied almost 85 percent, was less expensive than the $7.29/Dth average cost of the remaining 12 suppliers, and was less expensive that the $5.93/Dth average cost for all of the suppliers. In this FY, the concentration of supply from Enron did not appear to disadvantage North Shore.

In FY2000, the first year of the GPAA contract, Enron supplied 87.9 percent of the commodity to North Shore from among 22 suppliers. Enron at $3.13/Dth was the lowest-cost supplier from among the top five that averaged $3.19/Dth and supplied about 97 percent of the commodity to North Shore. Enron's cost was also less than the average cost of $3.31 from the remaining 17 suppliers, and less than the average cost of $3.20/Dth from all suppliers. In this fiscal year also, the concentration of supply from Enron did not appear to disadvantage North Shore.

In FY1999, [redacted] supplied 52.8 percent of the commodity to North Shore from among 23 suppliers. [redacted] at $2.18/Dth was the lowest-cost supplier from among the top five that averaged $2.27/Dth and supplied almost 80 percent of the commodity to North Shore. [redacted] cost was greater than the average cost of $2.08 from the remaining 18 suppliers, and less than the average cost of $2.23/Dth from all suppliers. In this FY, the cost data suggest North Shore might have benefited from purchasing additional commodity from among the other suppliers. However, the price spread between [redacted] and the average of the 18 smaller suppliers was within five percent.

[290] Response to Data Request #144.

It is also noteworthy that North Shore did not have contracts comparable to the gas-supply and asset-management contracts Peoples Gas had with [redacted] and [redacted], and fared better. Gas Supply stated that the smaller and simpler North Shore system did not need the combination contracts, yet the GPAA contract was a combination contract.[291]

For FY2005 and 2006 when Peoples Gas had the two big combination contracts with [redacted] and [redacted] and North Shore did not, the average unit cost for commodity was less for North Shore than for Peoples Gas by $0.14/Dth in 2005 and $0.47/Dth in 2006. In fact, North Shore's average unit cost for gas was less than Peoples Gas for all FYs except 2002. The North Shore contract did not contain the Baseload Price Adjustment provision.

The data for both Peoples Gas and North Shore do not reflect a concern on the part of Gas Supply about supplier concentration for commodity. Liberty found no evidence of concern for concentrated commodity supply or initiatives to increase the number of suppliers. Liberty heard interview comments[292] on the intent to try to obtain additional suppliers and saw within the RFP analysis documents[293] that some new suppliers were being phased in gradually. However, throughout the audit period, the top five suppliers provided an average of 77 percent of the commodity to Peoples Gas and about 86 percent for North Shore, with no apparent attempt to decrease this concentration.

iv. Geographic Diversity

Seven pipelines serve the Chicago market, all of which directly interconnect with Peoples Gas, and two of which directly interconnect with North Shore.[294] Both Utilities receive customer-owned gas from all directly connected pipelines, and purchase at the city gate gas that can be sourced on any of the directly connected pipelines. Currently both Utilities purchase commodity bought in the field on two of these pipelines; *i.e.*, Natural Gas Pipeline Company (NGPL) and Northern Border Pipeline Company (NBPL). Liberty found these same two pipelines prominently specified in RFP documents throughout the audit period.[295] The field areas for these two pipelines are different geographic regions, with NBPL coming from Canada, and NGPL servicing the Gulf Coast and Mid-continent producing regions. Both utilities currently hold storage on NGPL and ANR Pipeline, which are located in different areas of the country. ANR also pulls gas from the southwest.

The table below gives Gas Supply's approximation for the geographic diversity of commodity supply for each Utility.[296] They noted that they could not identify the original sourcing of the commodity purchased at the city gate. Purchases designated from the other regions were purchased in those respective regions and transported by each utility.

[291] Interview #18&19, February 7, 2007.
[292] Interview #2, January 18, 2007, Interview #18&19, February 7, 2007.
[293] Response to Data Request #48.
[294] Response to Data Request #85.
[295] Response to Data Request #48.
[296] Response to Data Request #86, and stated as consistent with responses to Data Requests nos. 55 and 58.

Geographic Diversity for PGL and NSG
(%)

FY	1999	2000	2001	2002	2003	2004	2005	2006
PGL								
Chicago Citygate	16.1	88.1	86.2	79.3	82.7	80.0	42.2	41.8
Canada	20.8	0.0	0.0	9.4	0.4	0.0	45.1	49.7
Mid-Continent	40.5	4.7	4.1	4.3	4.1	4.2	0.0	0.0
Gulf Coast	22.6	7.2	9.7	7.0	12.8	15.7	12.7	8.5
NSG								
Chicago Citygate	21.2	93.3	89.0	65.1	83.7	84.0	13.1	8.2
Canada	70.8	0.0	0.0	18.9	0.0	0.0	56.6	60.2
Mid-Continent	6.1	3.1	8.3	12.5	13.6	11.9	26.6	27.2
Gulf Coast	1.9	3.6	2.7	3.5	2.7	4.2	3.8	4.4

More apparent geographic diversity for each utility can be seen outside of the five GPAA years of FY2000 through 2004 (with one month in FY2005). For those five years, the suppliers delivered to the city gate and Gas Supply was not necessarily aware of the commodity's geographic sourcing.

C. Conclusions

1. Peoples Gas and North Shore used a portfolio approach to provide appropriate reliability, flexibility and diversity by layering commodity purchasing and management to support commodity sales.

This portfolio approach has dimensions of supplier and geographic diversity, commodity layers, and laddering time lengths for term contracts. The layered commodity approach enables being prepared for needing more gas than plan via call and spot gas, but not having purchased excess commodity. Even though categorization of these procurement layers was not rigorous, the procurement pattern for Peoples Gas was clear, with baseload gas clearly being the major layer, ranging from about 66 to 85 percent, followed by the seasonal spot/swing gas, followed by call gas being about two percent. For the smaller and simpler North Shore utility, the baseload gas was the overwhelming component for commodity supply, ranging from about 70 to 93 percent, followed by spot gas, then call gas. These patterns are reasonable and rather typical.

Gas Supply's philosophy of laddering the term contracts to have some quantity of term commodity expiring each year in order to provide flexibility for forward contracting is reasonable and attractive for facilitating flexibility. However, as Gas Supply admits, the Utilities were not able to practice this philosophy during the GPAA five-year contract period of FY2000 through 2004 (plus one month in FY2005). Furthermore, even though Liberty found evidence of the laddering philosophy being implemented through the procurement process, Gas Supply did not have a master document that 'mapped' the laddering and rungs. Evidence of supply geographic diversity is more apparent for each utility outside of the five GPAA years during which the commodity was delivered to the city gate.

2. Supplier diversity was not adequate during the audit period. *(Recommendation V-1.)*

Liberty found no initiatives to increase the number of suppliers. Liberty did hear interview comments on the intent to try to obtain additional suppliers and did see within the RFP procurement/analyses documents some new suppliers gradually being phased in. However, throughout the audit period, the top five suppliers provided an average of 77 percent of the commodity to Peoples Gas and about 86 percent for North Shore, with no apparent attempt to decrease this concentration.

3. Both Utilities' city-gate purchases declined after expiration of the GPAA contracts.

When the GPAA contracts expired, both Utilities' city-gate purchases declined considerably. Peoples Gas' city-gate purchases declined from a range of 79-88 percent of its total purchases to about 42 percent. North Shore Gas, which did not enter a gas-purchase and asset-management agreement after its GPAA contract expired, saw its city-gate purchases decline from 65-93 percent of the total to 8-13 percent.

There was neither a clear cost advantage nor a clear disadvantage for city-gate purchases after expiration of the GPAA contracts. Peoples Gas bought at the city gate, both under combination contracts (gas supply and asset management) and on a spot basis. Prices under one of the combination contracts was above the other prices, and the other was below, reflecting mostly the different sourcing of gas under the two combination contracts. After expiration of its GPAA contract, North Shore Gas did not use a combination contract, bought less gas at the city gate than Peoples Gas did, and paid lower prices.

The Utilities have suspended their use of combination contracts, which provide for supply delivered to the city gate, pending the FERC's resolution of the legal status of such contracts. Both Utilities use city-gate deliveries in capacity options for peaking, however. Use of city-gate deliveries for those contracts is advantageous, as the Utilities can accept bids for supply at many more city-gate points than are available under their transportation and storage contracts. Thus, many more suppliers can compete for that type of supply.

4. Gas Supply typically did not operate under written procedures. *(Recommendation V-2.)*

The processes used by the Utilities have generally resulted in appropriate contracts. They did not have written procedures for their commodity procurement or off-system sales activities, however. The Sarbanes-Oxley (SOX) documentation process flow diagrams represented a foundation, but should have been developed into written procedures.

5. The RFP process used by both utilities was reasonable, but could be improved for bids requiring multiple supplier deliverables. *(Recommendation V-3.)*

Liberty found that the documentation, analyses, and decision-making process outlined in the RFP guidelines was well followed for cost-effectiveness and reliability, but efforts could be made to get additional suppliers into the pool of qualified suppliers. Typically, about 10 to 20 counter-parties simultaneously received an RFP package electronically (or via facsimile early in the audit period) for Peoples Gas and for North Shore so that neither utility would be potentially time disadvantaged. Respondents often submitted multiple bids containing different choices for the utilities. Bids were opened and evaluated as the guidelines described. Usually, cost was the primary determinant among reliable suppliers for selecting the winners in a price-ordered fashion. Occasionally supply diversity played a minor role. Sometimes there would be an insufficient number of respondents to enable Gas Supply to feel comfortable in subscribing all of their commodity need at a particular location for a term contract, and they would decide to handle the unsubscribed quantity on a month-to-month spot basis. The RFP process used in FY2000 through 2002 contained the same philosophical and strategic approach, as did the RFP process from FY2003 through 2006; the RFP paper trail shows the RFP process to have been implemented more effectively beginning in FY2003, however. Inclusion of the Transaction Confirmation along with additional credit-related requirements as part of the bids made for a more efficient process.

Liberty examined the RFP package that resulted in the optimization contracts with [redacted] and [redacted] for Peoples Gas. These contracts provided the bulk of Peoples Gas' supply for FY2005 and 2006 and their RFP combined a number of different supply and service requests. The bid asked for one combined aggregated cost for the different supply and service requests, rather than for a delineated as well as a combined cost bid. This aggregated cost bid made analyzing the bids difficult for Gas Supply.[297] Peoples Gas received a sufficient number of aggregated bids from which to select two low-cost, operationally qualified, and credit-qualified winners. It is not possible to determine whether Peoples Gas could have done better by bidding the components separately.

Available data indicate that the aggregated pricing in the RFP was beneficial. However, even though the data lean in favor of the aggregated pricing being beneficial, the data do not totally resolve whether a disaggregated approach might have produced further benefits.

It is important to put this aggregated bid aspect of the RFP bidding process post GPAA into a larger context. Peoples Gas achieved commodity and supply flexibility for multiple years using an RFP process that permitted multiple suppliers to bid for a contract that did not have the GPAA onerous pricing provisions of Baseload Price Adjustment, Flexible Pricing, and penalty for selling back gas. This was a significant improvement.

6. Gas Supply did not perform after-the-fact analyses of supply planning effectiveness. *(Recommendation V-4.)*

Gas Supply does not perform any after-the-fact reviews, studies, or analyses to evaluate the cost-effectiveness of the supply planning process other than what was done in connection with gas charge reconciliation and other regulatory filings.

Gas Supply said that it analyzed for alternatives everything it did, such as daily dispatch, how to implement the portfolio, monthly alternatives, seasonal and longer-term alternatives, and RFP

[297] In comments on Liberty's Draft Report, the Utilities stated

> *The Company feels that the aggregated bid format simplified the analysis. This was a major reason for conducting the RFP in this fashion. The fewer the number of moving parts, the easier it was to evaluate the bids on an equal footing and with greater objectivity.*

alternatives. However, these types of analyses were largely optimization analyses that did not search competition results for unanticipated possibilities.

7. The Enron GPAA contract was the only significant commodity supply contract procured bilaterally. *(Recommendation V-5.)*

The Utilities used RFP processes to procure its non-GPAA commodity (that was not spot gas) during this FY2000 through FY2004 period.

In FY2006 and FY2005, Peoples Gas procured 91.5 and 95.5 percent, respectively, of its commodity through an RFP process. For North Shore, these percentages were 91.3 and 92.9, respectively. Thus, more than ninety percent of the commodity procured for each of the utilities in FY2005 and 2006 were procured via an RFP process, and the remaining 5 to 9 percent of spot gas was procured via bilateral negotiations or an electronic trading platform.

No detailed hard-copy procurement process data for FY1999 was available. However, indirect evidence from contract summaries, procurement quantity and supplier data, and interviews, confirmed that the GPAA was the only significant commodity supply contract done bilaterally. This suggests that an RFP process was used for the bulk of the commodity procured by both utilities for FY1999 outside of spot gas.

8. The Utilities abandoned off-system sales. *(Recommendation V-6.)*

The Utilities argued that, prior to the audit period, they had generally not produced positive results from off-system sales, so they modified their purchasing practices to avoid them. A primary objective of the GPAA contracts, for example, was to have the supplier operate the Utilities' pipeline capacity; any proceeds from secondary-market activities (such as off-system sales) would accrue to the supplier. The Utilities' customers were to benefit through reduced prices for gas at the city gate.

After expiration of the GPAA contracts, the Utilities continued to use gas-supply and asset-management contracts to avoid secondary-market activities. They also made certain portfolio adjustments designed to reduce further the occasions for off-system sales. They shifted the compositions of their capacity portfolios away from pipeline capacity towards storage, to be able to store excess gas rather than having to sell it. Throughout the audit period, they bought term gas on a warm-weather model, shifting more of their purchases into spot markets, again in an effort to avoid off-system sales. Consequently, the only time when the Utilities made off-system sales was when they could not be avoided; *i.e.*, when load conditions were such that the Utilities bought some gas that they had no place to put. The process for deciding to make a sale included a) identifying the source that is causing the excess, and b) finding a way to get rid of it.

However, throughout the period covered by this audit, affiliate Peoples Energy Resources Corporation (PERC) was building a substantial wholesale gas trading business, even as the Utilities were abandoning that market. Operating-income data presented in Chapter III suggest that, while margins in this activity were relatively thin, the activity was profitable.

As reported in Chapter III, Liberty's experience in reviewing gas supply activities at other utilities does not support a conclusion that utilities need be less effective at wholesale trading than their non-utility affiliates. Utilities and their non-utility affiliates may be in wholesale markets for different reasons,[298] but the nature of their activities in those markets, namely buying and selling gas at wholesale, is fundamentally the same. Liberty has generally observed significant positive margins from off-system sales at other gas LDCs. As also reported in Chapter III, PERC was created out of the Utilities' Gas Supply function, with literally the same individuals conducting trades for both the Utilities and the affiliate early in the period. It is simply unreasonable to argue, as the Utilities do implicitly, that the same individuals could not make money at wholesale trading when they worked for the Utilities, but they could do so when they moved to the affiliate.

9. Capacity that might have been released went into the Hub.

The Utilities also argued that, as was the case with off-system sales, they were not particularly successful in realizing value from capacity releases; therefore, their approach was to avoid the need to release capacity. The Utilities claim that concern over the deteriorating value of pipeline capacity assets was a major driver for the GPAA contracts, and the gas-supply and asset-management contracts that followed. After the Northern Border Extension entered service, the Utilities largely eliminated capacity contracts on pipeline systems other than Northern Border and NGPL as those contracts expired.

A result of the portfolio shifts described above was that any capacity that might be available for release was storage capacity, rather than pipeline capacity. As discussed below and in more detail in the Hub chapter (Chapter VII), any such available capacity is added to the assets used to provide Hub services. Now that Hub revenues are credited against Gas-Charge costs, Liberty does not find that approach unreasonable. As discussed below, Liberty recommends a market test to see whether another approach to capacity management might yield more benefit to Gas-Charge customers.

10. The Utilities' process for deciding how to manage leased assets could be improved. *(Recommendation V-7.)*

As noted above, the Utilities' objective was to have no capacity assets, either owned or leased, that were not required to meet their service obligations. As discussed in Chapter IV, Liberty is not persuaded that Peoples Gas, in particular, has attained that objective, and Liberty has recommended that Peoples Gas present proof to its next gas-cost reconciliation proceeding on that point.

[298] Utilities engage in what some call "demand-credit" transactions for the purpose of offsetting the cost of holding pipeline and storage capacity for their utility-service customers. Utility traders take paid-for capacity assets and look for a transaction that will yield a margin, while traders for the affiliates are trying to place capacity and commodity that they already own. There certainly should be a very high level of aversion to risk on the part of utility traders; however, the same skills and experience are relevant to both types of activity, and that there is no inherent reason why individuals who can generate positive margins when working for the affiliate, could not do so for the utility, even though differences in appetite for risk may affect the size of those margins.

For North Shore, and for Peoples Gas if it successfully discharges its burden of proof, some of the capacity that is required to be owned or under contract in order to meet its service obligations will not be utilized from time to time. The capacity required to meet a service obligation is generally determined based on design weather. At times when the weather is less severe than design weather, at least some of that capacity will not be required for meeting a company's service obligation.

This capacity, required to be owned or under contract in case design weather occurs but not utilized when the weather is not that severe, is the capacity that is generally used for secondary-market transactions: off-system sales, short-term capacity releases, etc. In the Utilities' case, this capacity is storage capacity, not pipeline capacity, because of their portfolio adjustments and their use of "combination" contracts for gas supply and asset management: the suppliers use the pipeline capacity, but provide a discount on the commodity to compensate the Utilities' customers for that use.

The temporarily available storage capacity has been managed as part of the Hub. As discussed in more detail in the Hub chapter (Chapter VII), Liberty views Hub services as the functional equivalent of secondary-market transactions from the point when Hub revenues began to be credited against Gas-Charge costs. In principle, Liberty does not have a problem with this arrangement. The question is whether other arrangements for management of the capacity would yield more revenue for crediting against Peoples Gas' Gas-Charge costs.

Peoples Gas used storage optimization contracts early in the audit period as a means of trying to extract some value from storage capacity that was not required to serve on-system customers. The principal reason for those arrangements, however, was the lack of alternatives for 10- and 20-day storage services, which were required for serving its load efficiently. Because those services were not available, Peoples Gas contracted for 75-day storages, and then worked with third parties (TPC and then Enron) to try to realize value from the capacity that was contracted but not required for on-system customers. After Enron failed, Peoples Gas incorporated the extra storage capacity into its overall capacity-management activities.

Hub services that use storage capacity include park-and-loan (PAL) transactions, and firm and interruptible storage services. It is difficult to compare the revenues that Peoples Gas derives from those activities today ($6.2 million from PAL plus $1.0 million from interruptible storage in FY2006) to the revenue that Peoples Gas derived from its storage optimization contracts ($0.3 million in FY2001), because of the different amounts of storage capacity involved and the different operating conditions that apply to current Hub services versus those that would apply to a storage optimization contract.

Peoples Gas markets some of the Hub storage services through requests for proposals. The results of these competitions represent a market test of the value of those services. Liberty recommends that Peoples Gas review with the Commission Staff in its Gas Charge proceedings the results of its recent competitions for Hub services, and discuss with them whether other types of competitions might be in order, or whether Peoples Gas might entertain offers for storage optimization services that might be compared with continuing to market the services through the Hub.

11. In four of five GPAA contract years, data suggest Peoples Gas may have been cost disadvantaged from a combination of supply concentration where the major contract had onerous pricing mechanisms. *(Recommendation V-8.)*

This top-one-supplier concentration did not occur in the other three audit years, and the utility did not appear to be cost disadvantaged then. For the pre-Enron period in FY1999, Peoples Gas had fifty suppliers with the top five providing only about 38 percent of the commodity Peoples Gas procured. This practice appears to have been advantageous to the commodity costs for Peoples Gas. During the GPAA contract period for FY2000 through 2004 (and into the first month of FY2005), Peoples Gas averaged 31 commodity suppliers. The top five suppliers provided an average of 85 percent of the commodity, and the top supplier provided an average of about 70 percent. In four out of five of these GPAA contract years, the data suggest that Peoples Gas was cost-disadvantaged. This concentration of supply with the GPAA contract is inherently contradictory to the portfolio philosophy and strategy that distributes commitments.

For FY2005 and 2006, Peoples Gas had an average of 25 suppliers with the top five providing about 79 percent of the commodity Peoples Gas procured. The two combination contract suppliers, [redacted] and [redacted], together provided an average of 41 percent. This supplier distribution did not appear to disadvantage Peoples Gas, and contracts did not contain the onerous pricing mechanisms of the GPAA contracts. However, the data suggest that analyzing the patterns of supplier cost for the different layers might be helpful in procurement analyses and structuring the procurement.

12. In three of five GPAA contract years and in one additional year, data suggest North Shore may have been cost-disadvantaged from a combination of concentrated supply and some onerous pricing mechanisms. *(Recommendations V-8, V-9.)*

The pattern seen for North Shore was similar to that for Peoples Gas in that concentration of supply often seemed to be a cost disadvantage to the utility. For the pre-Enron period in FY1999, North Shore had 23 suppliers, the top one provided almost 53 percent, and the top five provided almost 80 percent of the commodity North Shore procured. The cost data suggest North Shore might have benefited in this year by not concentrating its commodity procurement so much.

During the GPAA contract period for FY2000 through 2004 (plus the first month of FY2005), North Shore averaged 19 suppliers, the top five provided an average of almost 84 percent of the commodity North Shore procured, and the top supplier provided an average of about 65 percent. In three of these five GPAA contract years, North Shore appears to have been cost-disadvantaged by the combination of supply concentration and onerous pricing provisions, although its contract contained one less onerous pricing provision than did the Peoples Gas contract. This concentration of supply is inherently contradictory to the portfolio philosophy and strategy that distributes commitments.

For FY2005 and 2006, North Shore had an average of 14 suppliers and the top five provided about 97 percent of the commodity North Shore procured. This supplier distribution did not appear to disadvantage North Shore, but suggested that patterns of supplier cost for the different layers might be helpful in procurement analyses and structuring the procurement.

13. North Shore did not have contracts comparable to the combination contracts Peoples Gas had with [redacted] and [redacted], and fared better. *(Recommendation V-9.)*

In comparing the two utilities after expiration of the GPAAs, when Peoples Gas had two large multi-attribute contracts and North Shore did not, the average unit cost for commodity was less for North Shore than for Peoples Gas, by \$0.14/Dth in 2005 and \$0.47/Dth in 2006. In fact, North Shore's average unit cost for gas was less than Peoples Gas for all FYs except 2002. When the net effect of hedging (and other minor cost adjustments) are made on commodity unit costs, the actual costs between the two utilities were virtually identical for two years, Peoples Gas cost more by about two to five percent for four years, and North Shore cost more by 5.6 percent in FY2002 and by 1.5 percent in FY2004.

Gas Supply stated that the smaller and simpler North Shore system did not need combination contracts, yet North Shore's GPAA contract was an optimization contract. Once those contracts expired at the end of October 2004, North Shore procured baseload, summer fill, and spot gas without benefit of another combination contract.

14. The decision to agree to the assignment of the GPAA contract was reasonable.

Peoples Gas should not have entered into the GPAA for all of the reasons identified and discussed by the Commission and the parties to the 2001 Reconciliation Proceeding. The contract has all of the cited bad provisions, and Peoples Gas had compounded the problem by locking in forward gas prices just before prices dropped. Those elements gave the contract a lot of value, however, and the various interests in the bankruptcy proceeding should have been expected to fight hard to preserve that value. Thus, it seems unlikely that Peoples Gas could have saved customers money by fighting to break the contract, or by trying to buy its way out of the contract.

D. Recommendations

V-1 Develop a process to increase supplier diversity for both Utilities as much as possible without jeopardizing the benefits of the RFP process.

Gas Supply should develop a program for each Utility that will both decrease the concentration of commodity supply among one or a few top suppliers, and expand the number of qualified suppliers with whom Peoples Gas and North Shore have master agreements. Gas Supply should also analyze the bid and actual cost data from suppliers as a function of the commodity layers and use these analyses to gain insights for how to better structure future RFPs.[299] The Utilities

[299] In comments on Liberty's Draft Report, the Utilities stated

The Company is concerned that an objective solely aimed at increasing supplier diversity may work against its other stated objectives. The Company's supply acquisition should be in keeping with the overall philosophy:

- *Acquiring competitively priced natural gas supplies from diverse sources.*
- *Utilizing risk management tools to reduce volatility.*
- *Acquiring the necessary physical and contractual assets to meet customer demand.*
- *Extracting maximum customer value from the physical and contractual supply assets under its control.*
- *Designing the flexibility necessary to adapt to a changing environment*

should complete the implementation of this recommendation within six months of the date of this report.

V-2 Document procedures.

Gas Supply should document its procedures more completely. Liberty acknowledges that the Gas Supply team appears to have excellent verbal communications among themselves and that they are working on more documentation. The Utilities should complete the implementation of this recommendation within six months of the date of this report.

V-3 Ask for cost bids of the disaggregated components on any RFP that combines various aggregated deliverables.

Any RFP that combines various aggregated deliverables should also ask for the cost bids of the disaggregated components as well as the cost bid for the aggregate. The aggregated cost could be greater or less than the sum of the components, depending on whether the supplier needed to do extra work to aggregate and/or sensed an opportunity to charge more, or whether the supplier obtained cost savings by aggregating and could share a portion of that cost savings with the Utilities.

Even if the Utility had a reasonable data base for knowing the disaggregated costs, it would be good practice to ask the bidders to delineate their bids in order to gain additional insights, and to help decide if the components should be put out in separate RFPs.

The Utilities should complete the implementation of this recommendation within one year of the date of this report.

V-4 Routinely perform after-the-fact analyses to evaluate the cost-effectiveness of the supply planning process.

Gas Supply (and the Utility in general) should perform more after-the-fact analyses in addition to the usual optimization analyses. Liberty also recommends that Gas Supply do after-the-fact analyses of all major items, not just when a dislocation occurs. After-the-fact analyses of major items can provide important insights and can lead to improved processes and performance for the benefit of the utility ratepayers.

The Utilities should complete the implementation of this recommendation within one year of the date of this report.

V-5 Use an RFP process where a number of qualified potential suppliers simultaneously receive a request to bid on specific utility commodity needs for obtaining any meaningful term quantity.

Bilateral procurement, like that used for the GPAA contract, is not recommended for any term commodity quantities. Gas Supply maintains a list of potential suppliers meeting their financial and physical performance needs in the form of a list of suppliers with whom Peoples Gas and

North Shore have master contracts. These lists are the foundation for sending out RFPs. One of the more recent lists for each utility shows 26 suppliers for Peoples Gas and 23 for North Shore.

A bilateral procurement is characterized by the Utility communicating and negotiating with only one supplier. Bilateral procurement may make sense for minor spot gas requirements when the commodity must be procured within a day or so, when there is no time to conduct an RFP process, and when the broad and deep U. S. commodity market enables transparent pricing.

The Utilities should complete the implementation of this recommendation within one year of the date of this report.

V-6 Improve off-system sales performance.

The regulatory environment for wholesale natural gas trading has been under review by the U. S. Federal Energy Regulatory Commission (FERC) in FERC Docket No. RM07-04-000. That proceeding, which was informational, has recently been superseded by a rulemaking.[300] Within six months after the completion of the rulemaking proceeding, the Utilities should present to the Commission a report explaining why affiliate PERC/PEWM is considered to have the capability to generate consistently positive margins in wholesale trading while the Utilities are not. The report should address each of PERC/PEWM's principal business activities, the locations of those activities, and whether the Utilities are authorized to engage in them. If that report identifies activities and locations where the Utilities are authorized to compete, the Utilities should then submit to the Commission, within three months of the first report, a business plan for each such activity. If the Utilities believe that any delivery capacity that might be used for off-system sales is better left in the Hub, then the business plan report should demonstrate the superior benefit to Gas-Charge customers of that alternative.

V-7 Review recent competitions for Hub services with stakeholders.

Peoples Gas has conducted the sale of certain Hub services, particularly park-and-loan services, through requests for proposals. Liberty recommends that Peoples Gas review the results of those competitions to explore how those competitions realize value from Gas-Charge assets. The review should include discussion of other possible means of realizing that value, such as identifying certain assets to offer for third-party management arrangements.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

V-8 Analyze cost data by supplier within the various commodity "layers" (base-load, swing, winter spot, summer spot, call gas) that have characterized the Utilities' recent solicitations.

Gas Supply should analyze the bid and actual cost data within the layers, rather than simply considering the bids for all layers together, to gain insights for use in structuring future RFPs.

[300] U. S. FERC Docket No. RM08-1-000, *Promotion of a More Efficient Capacity Release Market*. A Notice of Proposed Rulemaking was issued in that proceeding on November 15, 2007.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

V-9 Continue commodity procurement for North Shore without the use of optimization contracts.

Commodity procurement for North Shore should continue without use of optimization contracts as it has done since early in FY2005. Data from the last two audit years suggest that this is the proper course of action. The average unit cost for commodity was less for North Shore than for Peoples Gas (who had optimization contracts) by $0.14/Dth in 2005 and $0.47/Dth in 2006. The smaller and simpler North Shore utility does not seem to require optimization contracts.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

VI. Price Mitigation

A. Introduction

Liberty examined the goals, strategy, procedures, and practices of the Utilities' hedging program. The principal questions addressed by the review were:

- What policies and procedures do the Utilities use for managing the risks associated with its hedging program?
- What are the objectives of the hedging program? Have the Utilities clearly defined those objectives?
- What strategies and instruments (futures, options, etc.) do the Utilities use in pursuit of their objectives?
- What are the qualifications of Company personnel involved in hedging activities?

There have not been ICC requirements or guidelines that address hedging. ICC Staff conducted a mid-2003 workshop that addressed the hedging of natural gas costs and the potential for developing rules or guidelines. The workshop did not produce widespread support for a specific, prescriptive approach. There was at the time no model existing for specific hedging rules or requirements; most states did not have any written hedging policy, although some had adopted general statements encouraging hedging.

The following table summarizes total hedging cost recovery from utility customers for the audit period.[301] PEC reports the 1999 costs as "small," but unknown.

Audit Period Hedging Costs

Fiscal Year	Peoples	North Shore
2006	[redacted]	
2005		
2004		
2003		
2002	None	None
2001	None	None
2000	None	None
1999	Not Available	Not Available

B. Findings

1. Risk Management Guidance: 1999-2005

The 36-page February 1998 PEC "Trading Risk Management Policy and Procedure Manual" guided trading risk management until 2005.[302] It adopted specific risk-management objectives:

[redacted]

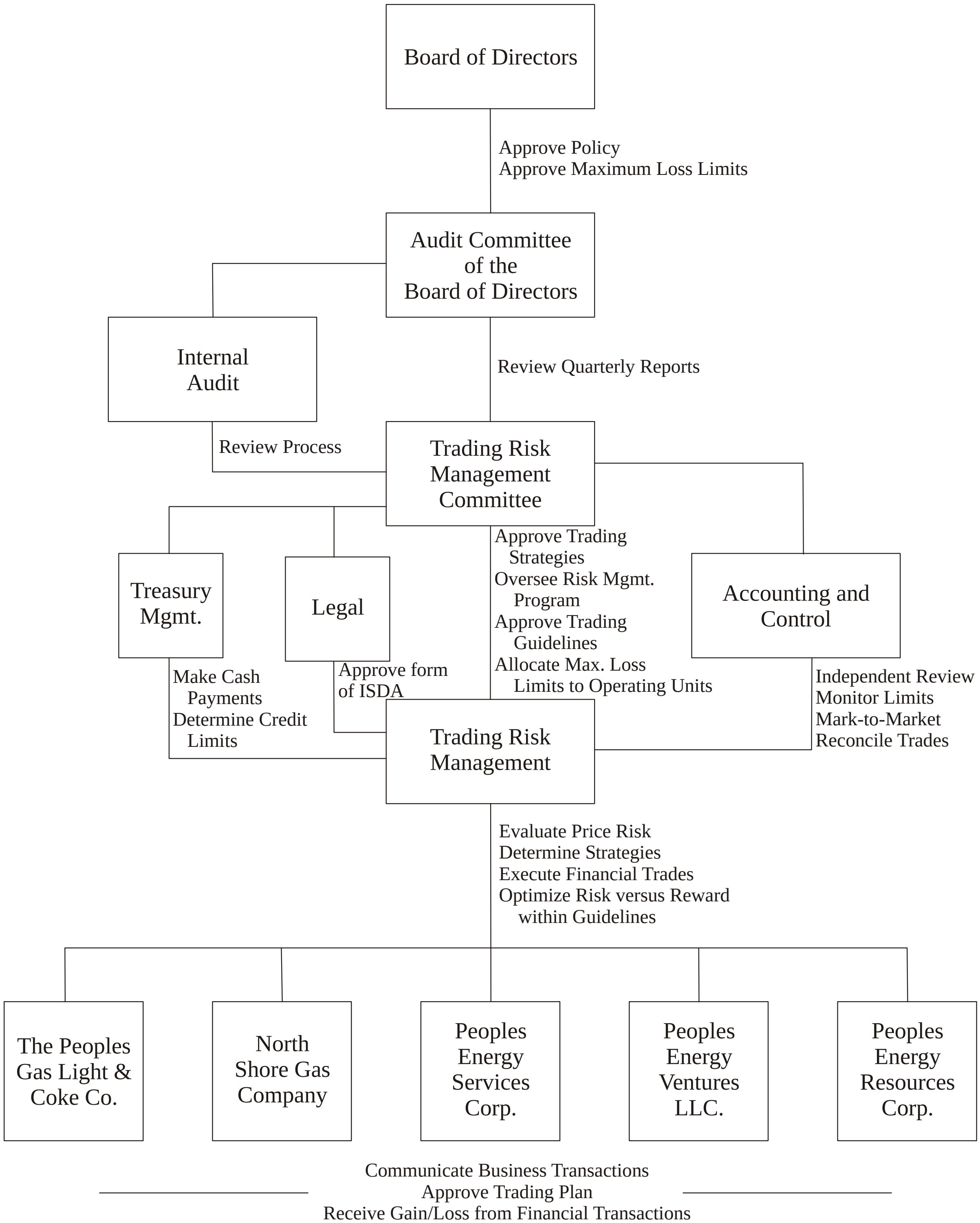
[301] Response to Data Request #191.
[302] Response to Data Request #6.

[redacted]

[redacted]

The 1998 manual created a formal series of organizations with trading risk management responsibilities. The diagram below illustrates this structure.[303] It shows that a common organization, from Trading Risk Management up through the PEC board of directors has had risk management responsibility for the Utilities and the non-utility subsidiaries.

[303] Response to Data Request #6.



The manual assigned responsibilities for risk-management functions to a number of organizations:

- Trading Risk Management Committee: senior management oversight of Trading Risk Management Program development and execution

- Accounting and Control: daily activity monitoring to ensure procedure adherence and to report directly to the Trading Risk Management Committee
- Trading Risk Management: execute financial trades after securing approval from the Trading Risk Management Committee and the appropriate Operating Unit
- Operating Units: bear responsibility for their trading gains and losses
- Financial Planning and Treasury: review and approve counterparty credit and make funds transfers
- PEC Board of Directors: understand risks and satisfy itself that necessary controls, culture, and procedures exist to manage risk; approve and change policy
- Audit Committee of the PEC Board of Directors: receive quarterly reports from the Trading Risk Management Committee
- Peoples Energy Chairman: specifically approve those persons authorized to trade financial instruments for all units.

The manual assigned to a Trading Risk Management Department the responsibility for managing price and volume risk from investments, assets, and trades from the operations of PEC and its subsidiaries in their capacities as marketers, producers, and transporters of natural gas and electric power. Energy commodity, interest rate, and other energy asset risks fell within Trading Risk Management's scope. The 1998 manual set forth the policies, procedures, organizations, and controls associated with the management of these risks. It provided for the development of "Trading Strategies" to address financial trading for each business unit. The manual required all financial trades to fall within the scope and limits of those strategies. Trading Risk Management and the business units were to work together in developing the strategies, which then required the approval of the Risk Management Committee.

The manual required at least monthly meetings of the Trading Risk Management Committee, and established its membership as the:

- PEC Chairman and CEO (who serves as the committee's chair)
- PEC President and COO
- PEC Executive Vice President of Peoples Energy Corporation
- PEC Vice President and Controller.

The committee had responsibility to:

- Allocate the established PEC-wide limit on loss exposure across subsidiaries
- Establish loss and open-position limits for each unit
- Approve financial trading strategies
- Monitor internal risk-management controls and procedures
- Report on program status to the Audit Committee.

The manual defined the covered operating units as Peoples Energy Ventures, Peoples Energy Resources, Peoples Energy Services, The Peoples Gas Light and Coke Company, and North Shore Gas. Each of these units had the following risk-management responsibilities:

- Communicate business arrangement details to Trading Risk Management

- Negotiate agreements based on price guidelines provided by Trading Risk Management
- Approve unit trading plans
- Take responsibility for the losses and gains of financial trades attributable to their business arrangements
- Use discretion in taking market risk in accord with established limits and approved trading strategies.

The 1998 manual detailed the responsibilities of each organization with financial-trading responsibility:

- Trading Risk Management
  - Identify and monetize the risk of each business transaction
  - Develop financial model strongly correlating physical price movements with a financial instrument
  - Design trading strategy to optimize profit and reduce risk
  - Secure appropriate approvals
  - Manage and execute trade strategies
  - Post financial transactions
  - Monitor market prices and inform operating units and Accounting and Control of substantial price, volume, and volatility changes
  - Develop pricing guidelines for the operating units
  - Direct actions to address loss exposures in excess of the [redacted] limit
- Accounting and Control
  - Monitor risk management process to verify compliance with policies, procedures, and trade strategies
  - Determine forward prices and portfolio mark-to-market
  - Use publicly available data to establish market prices
  - Generate position and mark-to-market reports
  - Independently review financial trading records
  - Reconcile financial trades with broker statements and confirmations
  - Verify margin balance accuracy
  - Report policy violations to Trading Risk Management Committee
  - Open all broker accounts
  - Inform brokers of changes in authorized trader designations
  - Report financial disclosures
  - Monitor credit exposure
  - Record operating-unit account entries to assign financial gains and losses
  - Initiate transfers to account for margin, trade settlements, and payment of commissions and fees.
- Treasury Management
  - Review and issue individual counterparty credit limits to Trading Risk Management

  - Transfer dollars as directed by Accounting and Control.
- Office of General Counsel
  - Approve Master Swap Agreements (ISDA contracts)
  - Review conformations of non-exchange trades
- Internal Audit
  - Conduct regular risk-management reviews
  - Report any violations to the Trading Risk Management Committee
  - Report significant violations to the Audit Committee of the Board of Directors
  - Periodically review Clearing Broker procedures
- Tax group
  - Inform senior management and the operating units of tax consequences of financial trading activities.

Trading strategies formed the 1998 manual's basis for authorizing and controlling the execution of financial transactions. It required the existence of a Trading Risk Management approved Trading Strategy outlining the business reasons, costs, revenues, and volumes of a business line and providing guidelines for hedging price risk. At the business-unit level (*i.e.*, Peoples Gas and North Shore as distinct utility units), a Trading Plan provided specific volume, price, term, location, seller/buyer and mitigation levels for specific transactions. The manual recognized the potential for new opportunities and accompanying new risks; therefore, it incorporated a means for adopting a new Trading Strategy to apply to them. The process for developing trading strategies included the following elements:

- Develop a report of business reason and risk addressing benefits, potential volumes and margins, time schedule, risk profile, costs, funding needs, and implementation plan
- Verify through a correlation study that there is a high correlation between financial instruments and price movements of the physical transaction
- Evaluate sensitivities/stress test the business model
- Test the model with historical data
- Describe the permissible financial instruments that can be used
- Describe the hedging approach
- Establish trade limits and market-position valuation
- Document controls, procedures, reporting requirements, and resources available to support the activity
- Describe tax and credit issues.

The 1998 manual also addressed data recording and accuracy needs, adopting the following requirements:

- Transaction trade tickets must identify the applicable trade strategy and unit as soon as the transaction is executed
- Errors should be resolved and corrected within 24 hours
- Accounting and Control must report significant dollar errors and policy violations to the Trading Risk Management Committee.

The manual required the use of outside credit rating services to supplement Treasury Management's other activities in managing counterparty credit risk. Chapter II of this report addressed credit risk management.

The manual defined what constituted qualified hedge transactions, using as a basis the guidelines for allowing hedge accounting:

- Designation as a hedge
- Reduction of exposure to price fluctuation
- High correlation between changes in market value of the hedge transaction and in the hedge item throughout the hedge period
- Probability that change in market value of hedging transaction and hedging item will substantially offset each other
- Identification of the hedging instrument to the underlying commodity through at least a clear economic relationship between the prices of the two.

2. 2005 Risk Management Policy

PEC conducted a review of industry practices in reviewing its risk manual. It cited what are comprehensive white papers published by the Committee of Chief Risk Officers and the use by the independent accountants of their checklist of industry best practices as examples of industry publications consulted as part of this review.[304] PEC changed its risk management governing documents in 2005, when it adopted:

- A three-page, Peoples Energy Corporation Risk Management Policy
- An accompanying 13-page "2005 Peoples Energy Corporation Market Risk Manual,"[305] which refers to 11 appendices that set forth additional details on practices, procedures, and those authorized to perform various roles related to trading.

The 2005 risk management policy begins with an objectives statement that authorizes the use of risk management trading to manage risk, but not to speculate. The policy defines allowed trading as consisting of:

[redacted]

The policy identifies those persons authorized to engage in risk management trading. Officers of PEC, including the chairman, president, vice presidents, CFO, and treasurer have authority to execute trade documents and to take other actions that they deem necessary to carry out the 2005 risk management policy. No person has the power to engage in risk management trading without the written authorization of the Chairman and CEO (or the designated senior officer in the case of a joint venture in which PEC or a subsidiary participates).

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[304] Response to Data Request #212.
[305] Response to Data Request #6.

The 2005 risk management policy limited risk management trade amounts to:

[redacted]

[redacted]

The policy limits counterparty risk by requiring either exchange-traded instruments or bilateral transactions limited to counterparties meeting dollar, maturity, and credit requirements established by the CFO, with approval by the Risk Management Committee, and having signed an ISDA (International Swap and Derivatives Association) or an agreement approved by the general counsel. The policy also gives the general counsel the ability to approve other, non-conforming agreements.

The 2005 risk management policy provides for oversight and guidance by a Risk Management Committee whose members the chairman and CEO would select from the body of senior officers, unless otherwise directed by the board. The 2005 policy's list of Risk Management Committee duties comprised:

- Reporting to the Audit Committee the established limits of each subsidiary and all changes thereto
- Reporting quarterly to the Audit Committee about risk management activities
- Approving all subsidiary risk manuals and procedures
- Approving strategies and allocating risk limits among subsidiaries and joint ventures
- Ensuring the existence of adequate controls, systems, and resources to comply with the policy and to operate under "industry best practices."

The 2005 risk management policy gives other specific responsibilities to a number of officers:

- CFO
  - Identifying and quantifying exposures
  - Developing forward curves
  - Reporting all major policy violations to the Audit Committee
  - Monitoring trading limits, exposure, hedge effectiveness
  - Providing the reports described in the Risk Management Manual to the Risk Management Committee
- Internal Audit Director
  - Reviewing adherence to the Risk Management Policy at least annually
  - Reporting the results of those reviews to the CFO and to the Audit Committee
- Senior Business Segment Officer
  - Cooperating with and implementing the policy and any procedures
  - Managing exposure within established maximum limits
  - Documenting transactions and following established record-keeping procedures.

The 2005 risk management policy also addresses the issuance of guarantees and letters of credit. The chairman, the president, the CFO, and the treasurer have authority to execute guarantees and to arrange for bank letters of credit. The board of directors retains the power to limit the maximum amount of such undertakings annually or more frequently. The Risk Management Committee acts as the overseer and monitor of these undertakings, and must report on their allocation and utilization to the Audit Committee at least annually.

The policy requires that management and personnel responsible for implementing it be familiar with the "Risk Management Policy" and the "Corporate Risk Manual." Business unit management has the authority to establish more detailed manuals to implement the policy for their operations, provided that the Risk Management Committee approves them in advance and has at all times an updated copy of them, and further provided that the responsible business unit leader reviews such manuals annually and reports to the Risk Management Committee the results of such reviews. The Risk Management Committee has not in practice followed this requirement. It does not conduct reviews of detailed procedures. Such reviews do take place, however, as part of annual SOX treatment of key controls. The Risk Management Committee has, however, reviewed the Risk Management Policy Manual, as part of its provision of that manual to the Board's Audit Committee for its approval. The Risk Management Committee also reviews any material changes to the Risk Management Policy as they occur.[306]

3. 2005 Market Risk Manual

A 13-page "2005 Peoples Energy Corporation Market Risk Manual"[307] complements the risk management policy. PEC issued it to define for all subsidiaries the processes and systems of controls intended to apply to bilateral contracts for the purpose of preventing business loss from market risk through assessment, consolidation, and reporting of exposures. The manual and related requirements must be updated and reauthorized by the Risk Management Committee annually, with any "substantial" changes requiring notice to the Audit Committee. "Material" alterations to the manual or to trading processes and procedures require prior approval of the Risk Management Committee.

The manual applied to all business units, which explicitly include:

- Treasury financing and investment activities
- Peoples Energy Resources Corp., including Power, Midstream, and Peoples Energy Midwest
- Peoples Energy Services Corp.
- Peoples Energy Production
- The Peoples Gas Light & Coke Company
- North Short Gas Company
- Peoples Gas Hub Services.

The manual required each unit to report to Trading Risk Management its risks created by any activities that entail market risk. Trading Risk Management then would work with each unit to

[306] Response to Data Request #219.
[307] Response to Data Request #6.

measure the risk exposure, which includes the identification of risk levels not offset through a physical or financial transaction or a pass-through mechanism (*e.g.*, the gas charge). The manual listed Financial Services as the central corporate authority for risk analysis, reporting, and transaction processing and obligated each unit to develop detailed procedures to support the aggregation of exposures throughout the corporate family. The manual then summarized the board of directors Audit Committee, and CEO roles, as expressed in the 2005 Risk Management Policy.

The manual listed the specific responsibilities of groups with risk management responsibility:

- Risk Management Committee
    - Articulating the company's "risk appetite"
    - Ensuring policy and manual enforcement
    - Allocating Board-approved risk limits among the business units
    - Ensuring effective policies and procedures
    - Monitoring risk exposures against limits at the corporate and business unit level
    - Measuring and monitoring risk exposure "rigorous"(ly)
    - Assuring appropriate oversight and compliance skills
    - Providing the board of directors with quarterly risk profiles
    - Notifying the audit committee of breaches of any approved limits
- Trading Risk Management
    - Identifying market risk
    - Calculating mark-to-market (MTM) valuations
    - Developing price curves
    - Monitoring positions and MTM values against limits
    - Executing for the business units the necessary financial orders with counterparties, provided that Trading Risk Management review confirms that the orders will comply with the hedge strategy
    - Enforcing and reporting market risk exposures to the business units, Risk Management Committee, and Audit Committee
    - Reviewing all new derivative product structures for policy and established strategy compliance
    - Assisting the business units to develop hedge strategies
    - Assisting the business units to perform correlations, analyses and other measurement techniques required for monitoring hedge performance
    - Ensuring that Financial Reporting and Compliance, the business unit involved, and the Risk Management approve all "Trading Strategies" before trade execution
    - Reviewing strategies annually for ongoing validity
    - Providing the underlying hedge correlation required by FASB 133, both at trade inception and quarterly[308]

[308] This activity concerns the demonstration required to qualify for hedge accounting, which is that a hedging relationship achieve with high effectiveness offsetting fair value or cash flows changes for the hedged risk (interpreted to mean a correlation ratio between 80 to 125 percent.)

  - Ensuring that aggregated financial and physical commodity transactions are consolidated in the "risk management system of record"
  - Monitoring each trade in that system of record to ensure compliance with strategy and propriety for Trading Risk Management's development of price curves, generation of value date, and creation and distribution of reports
  - Monitoring all trader and risk limits designated by the Risk Management Committee and reporting violations to the committee and/or the Audit Committee
  - Monitoring compliance with the aggregate and business unit loss limits
- Credit Risk Management
  - Reviewing, analyzing, underwriting, and approving all counterparty credit limits, parent guarantees, collateral management, and credit-term negotiation
  - Providing each business unit and Trading Risk Management with a current counterparty limit and exposure report in compliance with the "Company's Credit Policy"
  - Issuing and monitoring all counterparties' credit limits
- Gas Accounting (for both financial derivative and physical commodity contracts)
  - Performing transaction verification
  - Issuing third-party transaction confirmations (except that the PESC performs its own physical commodity contract confirmations)
  - Performing invoice issuance and reconciliation
  - Posting to the financial record the settled and MTM results of all derivative accounting transactions
  - Monitoring all financial trading activity daily to assure compliance with the risk policy, and with its own procedures and controls.
- Financial Reporting and Compliance
  - Reviewing all hedge strategies and contracts under the criteria for applying hedge accounting treatment
  - Setting policy for recognizing income statement losses and gains
  - Identifying the means for accumulating, summarizing, and classifying financial statement information related to derivative information
- Cash Management
  - Reviewing margin and collateral accounts daily
  - Disbursing additional margin at the request of Gas Accounting
  - Retrieving excess margin as appropriate for cash management needs
- Tax Administration
  - Reflecting hedging transaction results on income tax returns
  - Monitoring accounting entries and adjustments to book income
  - Defining the requisites for designating derivative products in accord with IRS requirements
  - Reviewing new derivative structures or products for tax implications
  - Providing requested advice on income tax qualification of any plans or transactions
- General Counsel

- Reviewing, editing, and approving master agreements, long-form confirmations, and non-standard contracts
- Internal Audit
  - Periodically reviewing the Risk Management function to provide an independent appraisal of controls
  - Reporting and significant control deficiencies or policy or manual violations to the Risk Management Committee and/or the Audit Committee.

[redacted] Credit must provide the Risk Management Committee with at least a monthly report on all outstanding counterparty credit exposures.

The manual limits business unit activities in the following ways:

- Requiring pre-trade evaluation with Trading Risk Management of each transaction's costs, revenues, volumes, and risk
- Requiring formal Trading Risk Management review of any new products for determination of risks, strategies, and fit with current policies, controls, and procedures
- Requiring the development of a "Trading Strategy" for each business line to prevent losses due to market risk
  - Trading strategies must outline business reasons, costs, revenues, and volumes for hedging market risk, set forth an implementation plan, and delineate hedge instruments, correlation analysis, controls, and any tax and accounting issues.
- Limiting trading to what is outlined in a Trading Strategy approved by the Risk Management Committee
- Requiring compliance with procedures appended to the manual
- Requiring responsible business unit personnel to sign each applicable Trading Strategy and designate the authorized traders
- Limiting business unit head discretion not to hedge risk by establishing a "loss limit" approved by the Risk Management Committee
- Making business unit heads responsible for communicating at least weekly to Trading Risk Management the information needed for Trading Risk Management risk identification, measurement, monitoring, and control
- Monitoring its loss limit position, and reporting to Risk Management Committee of any exposures exceeding its limit
- Limiting trades to approved counterparties
- Prohibiting trades between regulated and unregulated business units
- Requiring trades between unregulated business units to adhere to the same requirements that apply to outside counterparties and including inter-company trading activity in regularly produced risk reports
- Requiring selection of brokers, dealers, and Futures Commission Merchants by Trading Risk Management with Credit Risk Management Review

- Updating when changed (and at least annually) by the Risk Management Committee of persons authorized to execute transactions
- Requiring checking (per Gas Accounting policies and procedures cited as Appendix 10) of confirmations on all transactions against the risk management system, with follow-up on all discrepancies
- Providing for joint trade reconciliation for derivative transactions by Gas Accounting and Trading Risk Management, in accord with department policies and procedures
- Providing for reconciliation of physical transactions by the appropriate business unit and Gas Accounting, in accord with department policies and procedures
- Requiring at least weekly (daily where possible) mark-to-market for all derivative activity and trading books, under price curves maintained by Trading Risk Management using publicly available data.
- Requiring those units that use forecasted physical volumes for determining hedging levels (*e.g.*, Peoples Energy Production Company) to use an "earnings at risk" benchmark in lieu of mark-to-market
- Requiring stress testing through sensitivity analysis modeling probable short- and long-term market price movements
- Requiring specific documentation for all financial trades: a risk analysis defined in the Trading Strategy, prior authorization of the unit head (or delegation of trade authorization through approval of a "Designation of Authorized Persons," trade tickets entered into the Risk Management System, required tax documentation
- Requiring reports (defined in Appendix 5) including:
  - Daily summary of trading activity reflecting realized and unrealized gains/losses and market value and corresponding notional risk
  - Weekly summary of trading gains and losses by unit
  - Daily summary of margin amounts for all open positions
  - Credit report (at least monthly) of accounts receivable and mark-to-market exposure by counterparty
  - Data specified by Tax Administration for IRS compliance
  - Monthly effectiveness report addressing compliance with SFAS 133
- Establishing a policy of trading-error correction within 24 hours of discovery, mitigation efforts by the CRO if correction is not possible, and immediate notification to the CFO and the Risk Management Committee if the error is material to financial records.

The document provided to Liberty has a signature page for Risk Management Committee member and Chief Risk Officer approval; the signature lines are blank, but its approval is noted in Risk Management Committee minutes.

4. Risk Limits

The 2005 risk management policy established baseline limits, subject to future change in accord with its procedural requirements. Those limits consisted of:

[redacted]

[redacted]

Two subsequent reports have addressed risk limits under the 2005 risk management policy. The Audit Committee used it to establish [redacted]. The Risk Management Committee distributed [redacted] among the parent's subsidiaries and joint ventures. The first Risk Management Committee report is in the form of minutes from its July 13, 2005 meeting. At that meeting, the Risk Management Committee reviewed the format of quarterly reports to the board of director's Audit Committee and the Risk Management Policy to be presented to the Audit Committee for approval. The Risk Management Committee discusses each business unit's commodity price risks, and methods for monitoring and controlling those risks. After discussing existing risk limits and required approvals, the Committee proposed to continue for fiscal 2006 existing risk limit (set for fiscal 2005) [redacted]

[redacted]

The Audit Committee approved this maximum, allowing the Risk Management Committee to distribute it among subsidiaries and joint ventures. The same limits, recommended to be continued at the Risk Management Committee's July 2006 meeting were approved by the Audit Committee for fiscal 2007.[309]

During this period, the Audit Committee also established, in conformity with Risk Management Committee recommendations an [redacted][310]

5. Utility Trading Strategy

Gas Supply has been responsible for the development of its risk management strategies, in consultation with the Trading Risk Management personnel.[311] Pursuant to approved strategies, Peoples Gas and North Shore both enter transactions designed to hedge natural gas costs. Trading Risk Management provides oversight and consulting for the subsidiaries in the areas of energy trading and risk management. Trading Risk Management also has responsibility for assuring compliance with risk management program requirements and for conformity of individual transactions with established and approved strategies. Trading Risk Management also executes the trades for the operating entities, [redacted]. No financial transactions take place between two PEC affiliates as counterparties or direct dealings with affiliates.[312]

[309] Response to Data Request #209.
[310] Response to Data Request #209.
[311] Interview #3, January 18, 2007.
[312] Interview #3.

a. August 1998 Strategy Statement

In August 1998, the Companies adopted their first formal strategy statement covering financial risk management in the gas supply area and began, for the first time, to implement a financially based gas price mitigation strategy. The Utilities operated under the August 1998 formal strategy statement covering the months of November 1998 through October 1999. This "Gas Supply Price Protection Financial Trading Strategy" adopted the goal of reducing volatility and increasing price stability, in order to provide "stable and reasonable prices" over time. The strategy supplemented natural physical hedges obtained through storage and through efforts to have gas suppliers use financial instruments to temper volatility on [redacted] The strategy contemplated the use of [redacted].

The strategy applied to [redacted] noting that the PEC President and COO must approve all hedge trading plans prior to implementation.

The Trading Risk Management Committee members, the Vice President (Gas) Supply Operations and Asset Management, and Trading Risk Management signed off on the strategy.

b. Winter 1998-1999 Strategy

The "Gas Supply Protection Financial Trading Strategy" accompanying the August 1998 Strategy Statement provides for hedging [redacted]

The trading plan provided for the use of futures contracts, fixed-price swaps, and option collars to accomplish a maximum of [redacted] The plan also required coordination with Gas Supply Administration with respect to prices and volumes of purchases and coordination of the removal of the financial hedges with corresponding physical purchases.

Exhibit A to the trading plan sets forth the analytical bases for examining the [redacted]

The executive vice president who then was the most senior utility officer, the Director Supply Acquisition & Asset Optimization and Trading Risk Management signed off on the adoption of this document.

c. April 1999-March 2000 Strategy

The strategy for the April 1999 through March 2000 period, developed in March 1999, retained the same objectives. It observed that warmer temperatures had the effect of depressing market prices, but that increased prices were likely across the period covered by this year's strategy. [redacted] The strategy required entry of the hedging transactions in "Primo" immediately upon execution. PEC began to us the Primo Risk Management system in fiscal 1999 to provide for automation of daily risk review and reporting activities. The strategy also required conversion of all financial positions to physical gas at expiration, absent authorization by the Trading Risk Management Committee to liquidate them earlier. Approval lines (which were blank) were provided for:

- PEC President and COO
- Executive Vice President (then the most senior utility officer)
- Other Risk Management Committee Members
- Vice President Supply Operations & Asset Management
- Trading Risk Management.

An amendment changed [redacted] The same persons indicated as approving the base document actually signed off on the amendment.

Liberty examined the documents that PEC used to monitor the execution of hedges against plans. The first reports that PEC provided post-date the time during which this particular strategy applied.[313]

d. April 19, 2001, Strategy

The April 19, 2001, "Gas Supply Price Protection Strategy"[314] began by observing that both price and volatility had increased. The document noted that ICC-Staff published April 17, 2001, "NOI Manager's Report" provided findings and recommendations about recent gas prices, and support for price hedging. This document provided a strategy for locking in prices for the period from May 2001 through October 2002. The Enron North America Gas Purchasing and Agency Agreements would serve as the primary physical basis for hedging, with price protection provided through forward purchases, NYMEX futures, and basis swaps under a portfolio approach that would provide for the application of a consistent plan in subsequent years. [redacted]

The strategy called for a [redacted] Allowed transactions [redacted] The strategy required transactions to be confirmed and entry into the "Altra Gas Management System" within 24 hours. [redacted]

[redacted]

[redacted] The documentation, reporting, and updating provisions were standard, citing Altra Gas Management System and the Primo/Epsilon Risk Management System as the recording systems.

All approval signature lines, except for the one provided for the Operating Unit were completed, by the following persons:

- PEC President and COO

[313] Response to Data Request #7.
[314] The page numbered 4 from the April 19, 2001, "Gas Supply Price Protection Strategy" provided as part of the response to Data Request #6 was missing, but provided in a supplement by e-mail on July 18, 2007.

- Executive Vice President (then the most senior utility officer)
- Other Risk Management Committee Members
- Vice President Supply Operations & Asset Management
- Trading Risk Management.

Fairly simplistic tracking of status against maximum hedge targets was outlined in the document and was performed using a spreadsheet listing separately for Peoples and for North Shore the following items for each of the ensuing 18 months:

- Volumes hedged
- Volumes remaining to be hedged to meet targets
- Percent of targeted amounts hedged
- Weighted average price (excluding basis hedges).

Compliance was reported frequently during the month (although the data provided did not address each day's status). [redacted] It separated neither the targets nor the hedged volumes by hedge type. [redacted]

[redacted]

[redacted] The following table shows hedged volumes from April 2001 through October 2002 as a percentage of target for the months of June 2001 through February 2002.

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[315] Response to Data Request #7.

Percent of Target Actually Hedged

Month	PGL	NS
	2001	
June	[redacted]	
July		
August		
September		
October		
December		
	2002	
January	[redacted]	
February		

e. February 13, 2002[316]

[redacted] The document cited the ICC's 2001 Notice of Inquiry into gas prices report.

[redacted]

[redacted]

[redacted]

Documentation, reporting, and updates provisions were standard, again referencing Altra and referencing Epsilon for risk management transactions. The document contained the following executed signature lines:

- PEC President and COO
- Executive Vice President (then the most senior utility officer)
- Other Risk Management Committee Members

[316] Responses to Data Requests #6 and #223.

- Vice President Supply Operations & Asset Management
- Trading Risk Management.

f. May 31, 2002, Revised Strategy

This "Revised Gas Supply Price Protection Strategy" superseded all prior strategies, specifically citing the one dated February 13, 2002. Its purpose was to [redacted]

[redacted]

[redacted]

Documentation, reporting, and updates provisions were standard, again referencing Altra Gas Management System and Epsilon Risk Management System. The document contained the following signature lines (not used in the version originally supplied, but supplemented by PEC with a fully executed copy):[317]

- PEC President and COO
- Executive Vice President (then the most senior utility officer)
- Other Risk Management Committee Members
- Vice President Supply Operations & Asset Management
- Trading Risk Management.

g. Addendum to May 31, 2002, Strategy

The May 21, 2002, "Revised Gas Supply Protection Strategy" [redacted] The recording,

[317] A supplement to DR 6, filed after the submission of Liberty's draft report to the company for comment, provided executed versions of all the strategy documents previously supplied without signatures.

documenting, and updating provisions discussed earlier applied. Signatures appear on all the signature lines, which include the positions noted earlier.

h. March 19, 2003, Revised Strategy

This strategy issuance replaces prior strategies, specifically including the May 31, 2002, version. [redacted]

[redacted] The Risk Management Committee had to approve transactions outside those ranges.

The following table shows those ranges.[318]

	2003											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Winter 03-04												
Min	[redacted]											
Max												
Summer 04												
Min	[redacted]											
Max												
Winter 04-05												
Min	[redacted]											
Max												
Summer 05												
Min	[redacted]											
Max												
Winter 05-06												
Min	[redacted]											
Max												
Summer 06												
Min	[redacted]											
Max												

[redacted]

[318] Response to Data Request #224.

The document contained standard recording, reporting, and update provisions (still citing Altra Gas Management System and the Epsilon Risk Management System), and was approved through the signatures of the same positions applicable to earlier strategies.

i. August 1, 2003, Revised Strategy

This document, which bears the actual date of October 28, 2003, states that it superseded prior versions, specifically citing the March 19, 2003, version. It covers the period from November 2003 through October 2006. [redacted]

[redacted]

[redacted]

[redacted]

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319 Response to Data Request #225.

[redacted]

Exhibits showed the amounts of hedge purchases that could be made at prices within the various quadrants included in the consultant's matrix. They are reproduced below.

Exhibit #3 – Winter Price-Driven Execution Limits
Prices as of August 2003 (Per RMI)

Winter Price-Driven Execution Limits			
Price Target	**Winter ′03-′04**	**Winter ′04-′05**	**Winter ′05-′06**
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Exhibit #4 – Summer Price-Driven Execution Limits
Prices as of August 2003 (Per RMI)

Summer Price-Driven Execution Limits			
Price Target	**Summer ′04**	**Summer ′05**	**Summer ′06**
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

The strategy set forth the minimum, time-driven purchase amounts, as shown below.

[redacted]

Authorized hedging instruments [redacted]

The strategy allowed discretion in what hedging tools to use, [redacted]

Exhibits 3 and 4 set maximum limits for the acquisition of future season hedge targets:

[redacted]

[redacted]

[redacted]

[redacted]

Documentation, reporting, and updating requirements were standard. Signatures appeared on the same approval lines applicable to previous strategies, which covered Risk Management Committee members, the head of the operating unit (Gas Supply), and Trading Risk Management.

j. January 16, 2004, Summer Volume Change

This revision increased targeted monthly hedge volumes for the May through October 2004 period. [redacted] The document shows the approval signatures of the same positions who signed earlier strategies.

k. September 7, 2004, Winter Hedge Volume Change

[redacted]

The document contains the signatures of the persons holding the same positions that approved earlier strategies.

l. Addendum to August 1, 2003, Strategy to Set Fiscal 2005 Target Hedge Volumes

An "Addendum to Revised Gas Supply Protection Strategy" (original strategy document dated August 1, 2003) set [redacted]

The holders of the same positions who did so for earlier strategies signed the addendum.

m. April 1, 2006, Addendum

This addendum sets forth [redacted]

[redacted]

[redacted] The following table summarizes the schedule requirements.

[redacted]

The same position holders who approved earlier strategies signed the document's approval lines.

n. Fiscal 2007and 2008 Strategy

The FY 2007 – 2008 "Price Protection Strategy" supersedes prior issuances, specifically mentioning the August 1, 2003, version. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The strategy:

- Allows 24 hours for confirmation of price, volume, deliver point, term, counterparty, and trader
- Requires a list of authorized traders
- Requires traders to understand program parameters
- Requires transaction entry into the appropriate system within 24 hours
- Requires transmission of transaction confirmations to Gas Accounting
- Calls for a weekly Mark-to-Market report from Trading Risk Management on the outstanding financial derivatives position
- Calls for a weekly program compliance report from Trading Risk Management.

The document shows approval signatures from the same position holders who approved earlier strategies, and adds a line for Financial Reporting.

6. Trading Authorizations

The CEO has authorized trading authorizations for financial derivative contracts. For example, the authorization document dated February 14, 2005 authorized:[320]

- Four named persons to open and close accounts, transfer funds, liquidate instruments, and execute master swap, brokerage, and other agreements (one only had authority to execute such agreements)
- Nine other named persons to transfer funds
- Five named persons to receive trade confirmations, daily equity wires, margin call notifications and monthly statements (all were included in the previous group of nine)
- Six named persons to trade in futures, swaps, options, and other financial instruments.

This list of authorizations was changed and expanded to 21 persons by the CEO in March 2006.

7. Risk Management Committee Membership

Risk Management Committee members at the beginning of the audit period included:

- PEC CEO
- Executive Vice President (then the highest utility officer)

[320] Response to Data Request # 205.

- President and COO
- Vice President and Controller.

By October 1, 2002, Risk Management Committee membership (with the head of Internal Audit attending, but not as a member) was:

- PEC CEO (Risk Management Committee Chairman)
- CFO
- Peoples Gas and North Shore President
- Executive Vice President, (Diversified and Gas Supply)
- Vice President, Strategic Planning.

Risk Management Committee members, effective July 8, 2004, (superseding and October 1, 2002, order) were (with the head of Internal Audit attending, but not as a member):[321]

- PEC CEO (Risk Management Committee Chairman)
- PEC CFO
- Executive Vice President, (Diversified and Gas Supply)
- Treasurer
- Controller.

8. Risk Management Reports

There have been quarterly risk management reports to the Audit Committee of the board of directors during the audit period. The format of these reports has changed during the audit period. The committee recently sought a more summary format, in lieu of the greater detail that had characterized reports to date. The content of the utility information provided has, however, not changed significantly.[322] Liberty examined the fiscal 2006 quarterly reports from the Risk Management Committee to the Audit Committee. They contained charts or graphs showing:

- Credit exposure amount by credit rating
- Details on credit exposure for each counterparty rated at below investment grade
- Credit exposure amounts by time outstanding (*e.g.*, >90 days)
- Maximum and actual amounts of guarantees and letters of credit by each PEC business unit (all were well within limits and total amounts were in each quarter half or less of aggregate limit)
- Gas distribution and PESC receivables amounts, aging, and reserves
- Non-utility unhedged amounts and compliance with limits
- Utility amounts hedged, to be hedged (showing satisfaction of hedge targets), and average price for all hedged volumes (using fixed price secured or current market price as applicable)[323]

[321] Response to Data Request #208.
[322] Response to Data Request #216.
[323] Zagorski Phone Interview; September 27, 2007.

- Summary of utility hedging gain/loss (*e.g.*, falling market prices over the 2006 fiscal year) [redacted][324]
- Comparison of projected versus actual utility gas purchase prices over time
- 10-year trend line for settled NYMEX gas and oil prices.

These quarterly reports comprise the top level of risk reporting. The Risk Management Committee relies upon a number of more detailed reports that routinely address market and credit risks. They included:

- Weekly
  - Mark to Market Report
  - Gas Supply Hedge Report
- Monthly
  - MTM and Open Position Reports
  - Gas Supply Hedge Report
  - Credit Report
  - Standard and Poor's Liquidity Report
  - Contingent Liabilities Report.

The regular weekly compliance reports to the Risk Management Committee cover the utilities, PESC, and PEP. There have also been PEC limit reports and daily P&L reports from the PEC wholesale marketing subsidiary Peoples Energy Wholesale Marketing, LLC, or PEWM).[325] These reports are all reviewed at the monthly Risk Management Committee meetings. The format of the weekly Utility Compliance report has changed over the course of the audit period. Formerly, it provided transaction details, which are now presented in summary form (with the detail used to provide the summary). The information in the weekly report is thus derived from a spreadsheet. The report shows data for the current and the next three seasons (*i.e.*, two summer and two winter seasons). The data points provided include the following hedge volume information, displayed separately for each of the two Utilities and aggregated:[326]

- Normal planned purchases
- Hedge target as a percent of normal planned purchases
- Volumes already hedged
- Volumes for which basis is also hedged
- Percentage of hedges that provide fixed prices (versus, for example, collared prices through options)
- Percent of target already hedged
- Amounts remaining to be hedged.

324 [redacted]

325 Response to Data Request #216.

326 Response to Data Request #216.

The report also provides the following price information:

- Prices per MMBtu obtained through hedges
- Strip prices (*i.e.*, futures prices per MMBtu for the season)
- Applicable dollar limit on total option premium costs
- Amount spent so far on options
- Amount still available to be spent on options
- Realized and unrealized hedge gains/losses for the immediate prior season
- Realized and unrealized hedge gains/losses for each of the four seasons addressed
- Current and prior fiscal year realized and unrealized hedge gains/losses.

This seasonal information is supported by a page detailing monthly hedge price and volume information. The report also, since early 2006, has provided a sensitivity analysis that shows pricing sensitivity (given hedges) to low, base, and high scenarios for both weather conditions and market prices for natural gas.

Weekly reports to the Risk Management Committee and other members of senior management have reported on hedge effectiveness and exposures. The monthly Risk Management Committee meetings provide a forum for summarizing, updating, and discussing these measures. The Utilities use the two principal features of their hedging strategies; *i.e.*, meeting the time-driven purchase requirements and the price-trigger matrix. Monaco provides mark to market information; volumes hedged, times of hedge instrument execution, and the price-trigger matrix provide the remaining data. PEC also performs an analysis to monitor change in volatility as hedges are executed.[327]

9. Forward Price Curves

The CFO delegated the risk-management policy responsibility for price-curve development to Trading Risk Management. Internal Audit and the independent accountants have responsibilities for verification. The key SOX controls include both development and verification activities.[328] Procedures detail the methods and information sources for Trading Risk Management's responsibility in establishing and verifying the price curves on a daily basis and for verifying them.

10. Trading Limit Monitoring

Monaco contains a module that provides for the automatic generation of a notification when an entered transaction exceeds a trading limit. Trading Risk Management and management of the unit for which the trade occurred must then determine the cause of what is at that point an apparent violation. PEC reports that no such Monaco notifications have so far resulted in a conclusion that a trader has violated actual limits. The Trading Risk Management trader verifies compliance with limits, and contacts the senior executive of the subsidiary involved for approval to proceed if the transaction will cause a limit to be exceeded.[329]

[327] Response to Data Request #215.
[328] Response to Data Request #213.
[329] Response to Data Request #215.

The Audit Committee has received only two notices of risk management violations during the audit period. The first one preceded the adoption of the first utility strategy. PEC could not locate documentation from the event, provided a very general description of it, noted that a process misunderstanding and noted that it produced no negative profit and loss consequences. The only other reported violation involved PESC. This affiliate exceeded the limit on the gas it could hold in storage, which resulted from an extended period of warm weather after December 2005. The situation was reported to the Risk Management Committee by e-mail on January 30, 2006. Corrective action (reducing subsequent month purchases of new gas) was taken.[330]

11. enovate Risk Management Policy

The enovate, L.L.C. venture operated under its own policy, effective October 27, 2000. It provided for a risk management committee consisting of one representative from each member (Peoples MW L.L.C. for PEC). The policy also provided for a Chief Risk Officer, in which position an Enron representative served. The execution of the policy for PEC came from the Vice President Supply Operations and Asset Management and an enovate Board of Managers member.[331]

The policy required deal information capture to be undertaken in accordance with the "accepted Risk Procedures and Control Guidelines." These were defined as, "guidelines for credit approvals, other controls and operating procedures with respect to trading activities and similar matters…"

12. Risk Management Reviews

Early in the audit period, Internal Audit and the independent accountants (Arthur Andersen at that time) audited controls over the Trading Risk Management function. This broad review addressed credit risk management, operations and processing, market risk management, accounting and disclosure, organization, and management reporting.[332] The November 1999 report concluded that adequate controls appeared to be in place and operating effectively, making no adverse findings and recommending no improvements. PEC began the use of the Primo Risk Management system in fiscal 1999 to provide for automation of daily risk review and reporting activities. Internal Audit conducted a review of the system, reporting its findings in April 2000. The report made a number of recommendations focusing on areas such as system documentation, use, training, report generation, and supporting procedures.

Shortly thereafter, Internal Audit conducted a review of the adequacy and effectiveness of Trading Risk Management procedures, issuing a March 2001 report. The audit examined:

- Consistency of trades executed with approved strategies and business plans
- Limitation of trading to authorized personnel
- Adherence to credit policy and guidelines

[330] Response to Data Request #214.
[331] Response to Data Request #211.
[332] Response to Data Request #217.

- Segregation of duties between trade execution personnel and those responsible for middle and back office activities
- Effectiveness and efficiency of operating procedures and reporting.

The audit found that some deals entered into the data capture system (PRIMO at that time) were not locked (required to prevent their details from being changed), some trades did not include ticket numbers (needed to allow them to be cross referenced), some persons not authorized to trade appeared as authorized in PRIMO, and some trades did not include an associated strategy. This audit demonstrated that adherence to procedural requirements in the development stage of the Trading Risk Management process was not rigorous in some respects, but was improving.[333]

Risk management activities also form part of PEC's SOX 404 key controls, which have undergone annual testing and certification since fiscal 2005. The particular key controls tested in what PEC describes as its "Commodity Trading" function include:

[redacted]

An outside consultant has provided benchmarking and strategy development and execution assistance since 2004. The consultant has made two presentations to the Utilities.[334] The first came in June 2004. Its background elements included:

- A review of commodity price volatility since the beginning of the 1998 winter season
- The commonality in 2004 price trends among all major energy sources
- A depiction of the relationship between energy price volatility and the value of the U.S. dollar.
- Weather prognoses (temperature and hurricane likelihood)
- Natural gas inventory projections for the coming winter season start.

The presentation then provided the results of an informal polling the consultant had taken of its customers. The results focused on the instruments used, parameters on the use of options, the factors driving hedging decisions, length of the future period addressed by hedging, percentage of requirements hedged, and benchmarks used to measure hedging performance.

The second, April 2005 presentation, focused on the practices of Midwestern utilities, placing [redacted]

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[333] Response to Data Request #217.
[334] Response to Data Request #192.

[redacted]

13. Commonality Between Utility and Non-Utility Financial Transactions

The use of Trading Risk Management to execute trades assists in controlling the potential for linking utility and non-utility financial trades in manners that could promote cross subsidization. The utility's use of exchanges and brokers to make transactions further mitigates this potential.

14. Integrys Organization Changes

Peoples Gas and North Shore have continued their own, individual hedging and risk management program since the merger. An eventual review of combining them may take place, but no changes are anticipated until after a focused examination. The role of Trading Risk Management appears to be undergoing change, with expectations that certain activities will be "pushed down" to each business unit, which will own and use their own processes for risk management.

The new Integrys organization will use a centralized service group for supply, but each utility will have its own supply management group. The common group will provide planning, modeling, and contract administration activities.[335]

C. Conclusions

1. PEC has conducted price mitigation activities throughout the audit period under the umbrella of an effective risk management program.

There has been a comprehensive policy that sets forth appropriate objectives, limits the use of hedging to price mitigation goals, requires the use of defined strategies with express limitations, and calls for the use of an appropriate range of transaction types. There have been adequate auditing and consultant reviews of policy and procedure design and execution.

2. The use of Trading Risk Management, which reports independently from the supply and trading operations (both utility and non-utility) that it has supported, has been a material contributor to controlling trading operations; its future role is uncertain. (*Recommendation VI-1*)

Trading Risk Management has had important roles in executing financial trades and in providing controls. A series of process flow charts (revised in June 2005) provided a concise description of those roles. Reporting on utility hedging and on other affiliate mark-to-market positions has been one of Trading Risk Management's important roles, which include:

- Prepare weekly reports for senior management, analyzing utility and PEP hedging programs and mark-to-market positions for other units

[335] Interview #32B, May 21, 2007.

- Met monthly with the Risk Management Committee to discuss the status of trading strategies
- Prepared all business units position, exposure, and market reports to support the presentation of hedging program details.

Trading Risk Management has also played a role in providing for proper control over new risks as they are identified. It works with the business unit involved to develop a strategy to hedge the risks associated with new business transaction types. Trading Risk Management then verifies that all appropriate parties involved have signed off on the strategy that is developed and approved by the Trading Risk Management Committee. Trading Risk Management also assures that business units perform their annual review and approval of all hedging strategies.

Trading Risk Management also executes financial trades for the Utilities (and non-utility affiliates except for PERC). The Utilities present financial transaction orders to Trading Risk Management, which verifies the existence of a covering strategy, identifies an approved counterparty or broker, and then executes the transaction. Trading Risk Management completes a trade ticket and enters its data into Monaco, which includes a module that verifies compliance with credit limits. Successful verification leads to the steps needed to confirm the trade with the counterparty. Failure of verification causes notification to Trading Risk Management, Internal Audit, and the business unit involved, in order to initiate corrective response. For PERC, Trading Risk Management performs a post-execution verification of a covering trade strategy and approved counterparty.

Trading Risk Management has used experienced, capable personnel in carrying out its risk management and hedging functions.

3. Utility price mitigation has operated under well-defined and appropriate strategies that have supported the goal of providing price stability; over time, those strategies have appropriately moved away from elements that seek to capture value by capitalizing on apparently favorable market conditions.

During the audit period, there have not been any formal ICC guidelines for Peoples Gas and North Shore to follow in developing and implementing hedging strategies. The absence of such guidelines has been common across the country. There exists in Illinois a wide variety of gas utility sizes and portfolio management approaches. The ICC has set a goal of price stability for consumers, leaving the state's utilities to formulate an appropriate strategy that meets their unique conditions.

Absent such guidance, the Utilities have used their internally developed views of customer interest to define their strategies. The core of those views, as reflected in audit-period strategies has always been mitigation of volatility, as opposed to price reduction. That core is appropriate, given that price reduction strategies necessarily involve at least somewhat speculative elements. Early in the audit period, the utility strategies did involve attempts to identify price triggers at which hedging transactions would be considered appropriate to enter. These triggers resulted from consideration of a combination of historical market information, qualitative discussions of expected market conditions across the near term future, and forecasts of prices.

As the audit period progressed, however, Peoples Gas and North Shore have moved toward a more time-driven approach to placing hedges in accord with established targets. This approach has continued to allow some (albeit a decreasing) discretion to advance the timing of purchases based on the identification of pricing "sweet spots." However, the approach requires that, regardless of market conditions, hedged volumes approach and meet targets by specified dates.

Liberty's review confirmed that progress toward established targets has been satisfactorily in accord with the time-driven approach. The consultant used by PEC provided benchmarking data that shows hedging by the Utilities to fall within the range of experience in terms of total volumes hedged. The data shows the Utilities' three-year window to be at the outer edge of experience; other Midwest utilities used an average window of a year or so less. Liberty considers the use of a three-year window to be appropriate, given the decreasing percentages hedged at the outer end of the period.

4. Peoples Gas and North Shore limited the amount of option premiums to a very small portion of total gas costs, but their continuation leaves a small element of speculation in the hedging strategy. (*Recommendation VI-2*)

The Utilities do not expose customers to significant risk using options; they limit total option premium expenses stringently and in accord with the benchmarks provided by the consultant that has been supporting the Utilities for several years. Nevertheless, the ability of options to provide net benefits (when compared with other hedging transactions) ultimately depends on correctly anticipating future market movements. Liberty has not yet found an energy utility that has shown special competence in market price predicting. Absent such special competence, options can still have a beneficial use; *e.g.*, in allowing customers to benefit from large market price reductions, which might not accrue if fixed-price physical purchases and financial futures form the only hedging tools. The absence of ICC standards addressing hedging, however, means that utilities, such as Peoples Gas or North Shore, determine on their own what value to place on price swing protection using transactions that can have significant premium costs.

The following table shows the gains/losses from utility hedging by fiscal quarter.[336] The Utilities do not enter hedges with the goal of producing positive value, but rather to provide for price certainty. Their use of options, as noted, does bring a small element of price speculation into their portfolio (in the sense of providing an opportunity through options to participate in downward market price movements). The next table shows that, since the Utilities have measured hedge values, their results have generated customer benefits overall. The values combine realized gains for the fiscal year to date, plus the unrealized value (based on current market prices) of transactions as yet unclosed. Thus, the proportion of the values represented by closed transactions increases through each quarter of a particular fiscal year. Values will also fluctuate with changes from quarter to quarter in market prices. The Utilities did not summarize and report such data prior to 2003. The table includes the costs of options in the calculations. Some of the quarterly reports to the Board of Directors Audit Committee (from which Liberty took the values shown) provide only thousands of dollars; those entries show "000" as their last three digits.

[336] Response to Data Request #295.

Peoples Gas and North Shore Hedging Gains and Losses

Q1 2003	[redacted]	Q1 2005	[redacted]
Q2 2003	[redacted]	Q2 2005	[redacted]
Q3 2003	[redacted]	Q3 2005	[redacted]
FY2003	[redacted]	FY 2005	[redacted]
Q1 2004	[redacted]	Q1 2006	[redacted]
Q2 2004	[redacted]	Q2 2006	[redacted]
Q3 2004	[redacted]	Q3 2006	[redacted]
FY 2004	[redacted]	FY 2006	[redacted]

* Not reported separately

D. Recommendations

VI-1 Continue the checks and balances that were provided under Trading Risk Management's traditional role in hedging activities; justify any material changes in a report to the ICC.

The post-merger organization structure and staffing were not settled as Liberty completed field work. There appears to be at least a significant possibility that Trading Risk Management will lose some of its historical roles in hedging. Liberty considers the use of this group in strategy development and in trade execution to have been a strength of PEC. It is not clear how the group's role will change and what functions will be moved to the business units. Integrys should deal explicitly with the effects of all changes in the controls environment that will result from process, activity, and organizational responsibility changes. The need for careful examination extends to the provision of adequate assurances that financial trades for the Utilities and for their affiliates will not be assigned or linked in any fashion that will cause the Utilities to cross subsidize their non-utility affiliates. The results of this examination should be comprehensively documented and presented to the ICC for review within six months of the date of this report.

VI-2 Demonstrate the value obtained through the use of option-based utility hedging transactions and conduct prior reviews with ICC staff of the limits on use of such transactions.

Peoples Gas and North Shore have been using option-based transactions for a sufficiently long time to develop a track record of their success. They should prepare an objective analysis of the financial performance of these transaction types and demonstrate their likelihood to produce positive future results. What comprises "positive" results should be clearly defined. The utilities should also review with ICC Staff a statement of applicable future limits (their traditional historical one has been to limit premiums for options to a very small, quantified portion of total gas costs). The Utilities should implement this recommendation within six months of the date of this report.

VII. Storage and Hub Operations and Activities

A. Introduction

1. Objectives

Liberty examined storage and Hub operations and activities to determine whether:

- The process Peoples Gas used to schedule Hub transactions in conjunction with injections and withdrawals from Manlove Field for ratepayers was appropriate
- Peoples Gas' Hub procedures ensured that its ratepayers and North Shore's ratepayers had priority access to Manlove field
- Peoples Gas' internal and external controls were adequate to ensure that its leased storage capacity was not used to benefit Hub customers and its affiliates
- Peoples Gas had in place sufficient controls to ensure customer rights were protected for injection and withdrawals from the Manlove and leased storage assets
- The FERC tariff language of Peoples Gas' limited transportation customer or Hub customer late-winter season injections that could supplant the planned injections by Peoples Gas for ratepayers
- Hub activities provide sufficient net benefits or revenues to ratepayers to justify continuing to offer the services.

In addressing these objectives, the criteria that Liberty applied included the following:

- The Utilities should have clear and appropriate objectives and consistent operating plans identifying and supporting all legitimate utility priorities and expectations
- The Utilities should clearly assign responsibility for meeting those objectives, priorities and expectations to senior personnel who are held accountable for performance
- The Utilities should make operational decisions and transactions in accordance with well-established and appropriate plans, and should report, explain and correct, if necessary, all deviations
- Transaction and injection/withdrawal scheduling should be appropriately coordinated, utility customer interests should be protected for injections and withdrawals, and priority access to the Manlove Field should be provided
- The Utilities should preserve appropriate benefits of leased storage capacity use for utility customers
- There should be analytically supported measurement of Hub expected future net benefits for utility customers.

2. Background

Peoples Gas has used its Manlove facility to store gas for its on-system customers and to provide storage services to third-party customers, including North Shore. The ICC's Order in the 2001 Reconciliation Proceeding[337] noted that Peoples Gas stored 27 Bcf of gas for "PGA

[337] ICC Order, March 28, 2006, Docket No. 01-0707.

customers,"[338] and 8 Bcf for "non-tariffed"[339] services. The Mahomet Pipeline connects Manlove to Peoples Gas' Chicago distribution system. The "Hub" has operated as a virtual entity; *i.e.*, it has had no distinct physical assets of its own, relying on Peoples Gas' leased and owned assets to provide services to third parties.

In the winter of 2000/2001, Peoples Gas and Enron entities entered into a number of transactions that raised questions about Peoples Gas' operation of the field. In particular, these questions dealt with operating procedures pursuant to which Peoples Gas allowed third-party customers access to the volumes stored at Manlove, the nature of the transactions with the third-party customers, and whether those transactions disadvantaged Peoples Gas' and North Shore's customers in favor of third-party customers.

The Commission's Order also noted that Peoples Gas and North Shore have leased storage capacity from interstate pipelines beyond what Peoples Gas owns at Manlove. Peoples Gas maintained that operational reasons prevented it from substituting the capacity at Manlove used for third-party customers for the leased storage services. The Commission did not render any decision on this point, noting, "The propriety of PGL's use of its purchased storage has never been an issue."[340] The Commission did, however, state that "…when third-party transactions involve use of PGA assets, use of those assets…must be prudent."[341]

B. Findings

1. Development of Manlove and the Mahomet Pipeline

The Manlove storage field includes 26,000 acres (approximately 40 square miles) located predominantly under central Illinois farm lands. There are now 153 storage wells drilled to the Mt. Simon formation, at an average depth of 4,000 feet. There are also 35 observation wells and two water disposal wells. Peoples Gas drilled the first test well at the Manlove site in 1959, installed the first compressors in 1960, and began initial injections in mid-1961. Testing of two shallower formations to store gas failed.[342] Ultimately, successful injections into the Mt. Simon formation began in 1964. Peoples Gas added the most recent wells between 1992 and 1995, when it drilled 20 new injection/withdrawal wells and three observation wells.

Peoples Gas has added other facilities, such as dehydration equipment and carbon dioxide removal equipment, from time to time. Operating pressure of the wells is 1,750 psig. The site currently has six active compressors: four 1400 hp units (installed in 1966), and 4500 and 5000 hp units (installed in 1973 and 1978).[343] The maximum daily withdrawal capability of the field is about 800,000 Dth.[344] For fiscal year 2006, 694,000 Dth of that capacity was allocated to Peoples Gas, and 63,000 Dth was allocated to North Shore on a peak day.[345] Peoples Gas

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[338] The Utilities refer to these as "Gas-Charge customers."
[339] This reference means non-jurisdictional to the ICC. The Hub's services are subject to regulation by FERC.
[340] ICC Order in Docket No. 01-0707, March 28, 2006, p. 92.
[341] ICC Order in Docket No. 01-0707, March 28, 2006, p. 94.
[342] The St. Peter formation in 1961 and the Galesville formation in 1963.
[343] FERC Docket PR04-2-000, Peoples Response to Staff Requests, March 8, 2004, p. 2.
[344] Kickoff Meeting presentation, p. 32.
[345] Kickoff Meeting presentation, p. 45.

maintains that Hub storage services are subject to interruption;[346] they have, however, never been interrupted.

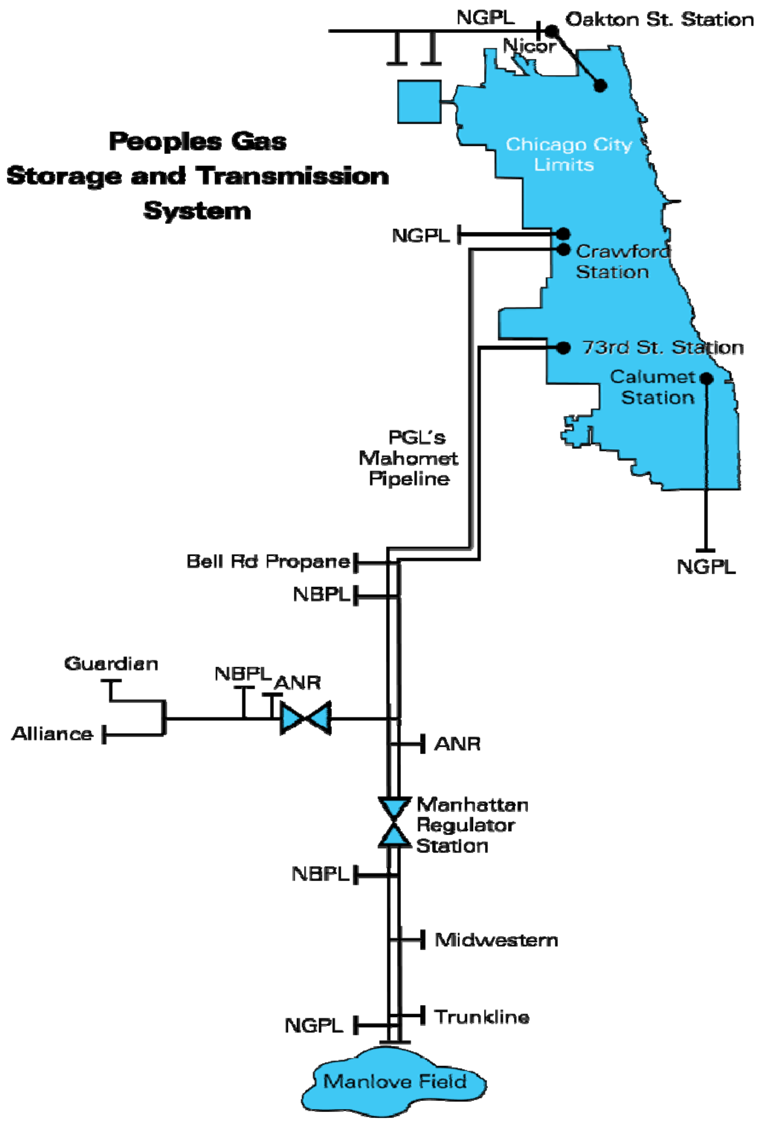
Peoples Gas added LNG facilities at the Manlove site in 1972 and 1973.[347] They consist of two LNG storage tanks, each capable of storing about 1,000,000 Dth of natural gas as a liquid. Vaporization facilities have a maximum rate of 300,000 Dth/day, all of which is dedicated to Peoples Gas on a peak day. Liquefaction equipment can convert gas to LNG at the rate of 10,000 Dth/day.

Peoples Gas built the Mahomet pipeline in stages. In 1967, it installed Mahomet Line #1, a 125-mile-long, 30-inch pipeline connecting the Manlove site to the Peoples Gas distribution system. In 1972, it installed parallel to Mahomet Line #1 55 miles of new 42-inch pipeline running from the city of Chicago to the Kankakee River. In 1989, it installed 70 miles of 30-inch pipe to connect the 42-inch line from the river to Manlove. Peoples Gas refers to the 1972 and 1989 routes together "Mahomet Line #2." The Mahomet pipeline now consists, therefore, of two parallel, high-pressure transmission lines from Manlove to the Peoples Gas' city gates. From Manlove north to the Manhattan regulator station, the pipelines operate at a maximum allowable operating pressure (MAOP) of 850 psi. From that station north to the Peoples Gas' city gates, they operate at a MAOP of 514 psi.

Four interstate pipelines (Midwestern, Northern Border, NGPL, and Trunkline) interconnect with Mahomet on the south side of the Manhattan station, between Manlove and the station. The Utilities can use gas from those pipelines to provide flowing gas to Peoples Gas' city gates or to inject gas into storage. Mahomet has two direct pipeline interconnections on the north side of the Manhattan station: one with ANR and one with Northern Border. Also, north of the Manhattan station, Northern Border, ANR, Alliance and Guardian interconnect through a lateral.

The diagram below shows the Mahomet Pipeline and its interconnections.[348] The Manhattan regulator station is also the location of Peoples Gas' odorization facility. The Bell Road propane plant, owned and operated by Peoples Gas affiliate PERC, also feeds into the Mahomet Pipeline.

[346] Interview #11, February 7, 2007.
[347] Response to Data Request #231, Response to FERC Question 2.
[348] Response to Data Request #166.



2. Development of the Hub

Peoples Gas created the Hub in the late 1990s. Hub services have included: (1) firm and interruptible transportation and storage services, (2) park-and-loan service,[349] and (3) title-tracking service. Peoples Gas has cited a number of reasons for creating the Hub:

- Optimization of existing infrastructure
- Use of strategic location
- Generation of incremental revenues that would minimize the need to file a rate case.[350]

FERC approved the Hub services offered and rates charged for those services in several proceedings:

[349] Peoples Gas defines park-and-loan services as services that combine storage and transportation.
[350] Response to Data Request #231.

- A November 1997, Peoples Gas application seeking approval of firm and interruptible transportation rates and a blanket certification to transport gas.[351, 352]
- FERC granted blanket certification by order dated March 2, 1998[353]
- FERC approved transportation rates by order dated March 11, 1998
- FERC approved storage, and park-and-loan rates by order dated March 3, 1999[354]
- A Peoples Gas April 2001 request for approval to reduce its maximum rates slightly; approved in submitted compliance filings in May 2001 (effective December 1, 2000)
- In November 2006, Peoples Gas filing for approval of a new, firm, one-cycle exchange service (a service that had previously been offered as a blanket-certificated or non-Operating-Statement service), and a slight reduction in its rates for most other services.[355]

Peoples Gas now offers the following services pursuant to its FERC Operating Statement:[356]

- Firm Transportation
- Interruptible Transportation
- Firm Storage
- Interruptible Storage
- Park and Loan
- One Cycle Exchange.

In response to its initial filing, Peoples Gas also received approval for a Title-Transfer service. There were never any customers for that service, which Peoples Gas eliminated in its October 2006 filing. Peoples Gas provides other services pursuant to the blanket-certificate authority.

3. Management of the Field

Peoples Gas owns and operates the Manlove and Mahomet facilities. It dedicates no specific physical assets to the Hub. Peoples Gas employees operate all facilities, but do not dedicate separate individuals or use distinct operating practices or procedures to do so. Personnel from Peoples Gas' Gas Supply, Gas Control, and other departments perform all the activities required to manage and operate the facilities.

Peoples Gas has had no specific written policies, procedures, or practices for the management or operations of the field. Liberty asked for all policies, procedures, or similar documents in effect during the audit period addressing metering, inventory verification, and determination of cushion gas requirements.[357] Peoples Gas responded with reference to its response to an earlier data request that included various reports, analyses, memoranda and other documents, but contained

[351] Response to Data Request #13.
[352] Peoples Gas does not qualify for the Hinshaw exemption from FERC regulation under the Natural Gas Act when it provides Hub services. When Peoples Gas provides Hub services, all the gas is received from and redelivered to customers within the boundaries of one state (Illinois), that gas is not necessarily consumed within that state.
[353] 82 FERC Par62, 145.
[354] 82 FERC Par61, 239; 86 FERC Par61, 226.
[355] Response to Data Requests nos. 188, 173, 231, and 232.
[356] Response to Data Request #13.
[357] Data Request #185.

no operating policies, procedures, or practices. Peoples Gas stated in an interview that it operates the field with the benefit of the 40 years of cumulative knowledge built up by operating Manlove Field.[358]

The 38-person Gas Storage department of Peoples Gas has operated the Manlove storage field facilities and the LNG facilities at the Manlove site. Gas Storage also maintained the Mahomet Pipeline from Manlove to the Ford/Kankakee county line, and maintained the Mahomet Lateral.[359] The Manager of Gas Storage has supervised the department. He is resident at the Manlove site and reports to the Director of Gas Supply & Hub Services. That Director in turn reports to the Vice President of Gas Supply and Engineering. The Director and the Vice President work from Peoples Gas' headquarters building in Chicago.[360] Some titles and levels of the responsible personnel changed over the audit period. Gas Storage has nevertheless operated (with one exception) as a separate organizational unit reporting to a director who reported to an officer-level position. The exception was during a transitional period in 2005, when Gas Storage reported directly to a vice president.[361] Neither the current Director of Gas Supply & Hub Services nor the Vice President Gas Supply and Engineering has experience in either gas transmission or storage operations. The Director's background includes rates, customer relations, and auditing and financial reporting, and the Vice President's is in information services and distribution engineering.

Various organizational units under differing senior managers have had responsibility for directing or monitoring and tracking the various operating parameters of Manlove. For example:

- Gas Supply and Gas Control – specify dates and volumes of injections and withdrawals[362]
- Gas Storage – manage physical operations and physical inventory verification
- Gas Accounting – record and track inventory levels and cushion allocations
- Gas Accounting – record and track cost of gas
- Plant Accounting – handle depreciation of cushion gas.

4. Manlove History

a. Operating History

Manlove Field is an aquifer reservoir. A FERC Staff Report describes the three principal types of underground natural gas storage:[363]

- Depleted reservoir – a depleted natural gas or oil field, typically located close to a consumption center. Such a field is a permeable rock formation confined by impermeable rock or water barriers. Working gas capacity is typically 50 percent of the total capacity of the reservoir, with the other 50 percent being cushion gas. On average, depleted reservoirs are the cheapest and easiest to develop, operate, and maintain, because

[358] Interview #44, June 14, 2007.
[359] Response to Data Request #166, p. 29.
[360] Pre-merger organization in January 2007.
[361] Response to Data Request #1.
[362] These decisions are made in consultation with Gas Storage, but Gas Supply has the final word.
[363] *Current State of and Issues Concerning Underground Natural Gas Storage* (FERC Staff Report), Docket No. AD04-11-00, , Sept. 30, 2004.

facilities are already in place from the production phase, and because the geological characteristics of the reservoir are already well known.

- Salt Cavern - a cavity leached or mined from a naturally occurring salt formation, developed mostly along the U. S. Gulf Coast. The walls of salt caverns have very high structural strength, and little gas escapes other than that withdrawn. Salt cavern capacity is typically only 20 to 30 percent cushion gas, with the remaining capacity working gas. The working gas can generally be cycled 10 to 12 times per year. Salt caverns are characterized by high deliverability and injection capabilities.
- Aquifer reservoirs – water-bearing rock formation overlain by an impermeable rock cap. Aquifer storage facilities typically have high cushion-gas requirements, ranging from 50 to 80 percent of the total gas in the reservoir. Because they are more expensive to develop than depleted reservoirs, aquifer storage facilities are usually used only in areas where there are no nearby, depleted reservoirs. Aquifers are the least desirable and most expensive type of natural gas storage facility because the geological characteristics of each aquifer must be discovered, costing time and money, and because they have very high cushion-gas requirements.

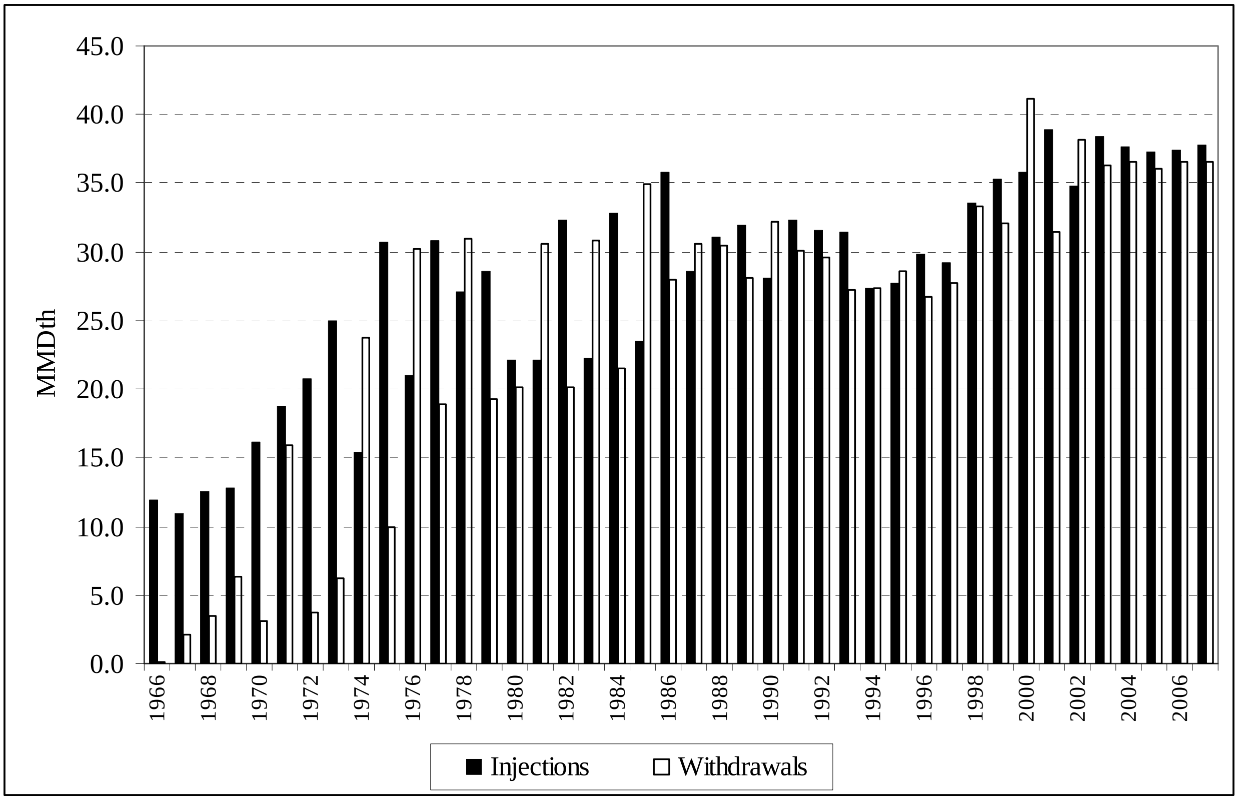
The table below contains a summary of the operational characteristics of the three types of storage fields in the U. S., based on a FERC Staff analysis of FERC filings:

Operating Characteristics of Storage Facilities by Type

Storage Type	Cushion Gas %	Injection Period (Days)	Withdrawal Period (Days)
Aquifer	50 to 80	200 – 250	100 – 150
Depleted Reservoir	50	200 – 250	100 – 150
Salt Cavern	20 to 30	20 - 40	10 – 20

Manlove's approximately 78 percent cushion gas requirements place it at the high end of the range of the aquifer type of storage, which is already the most expensive to develop of the three types.[364] Manlove's operating characteristics have caused Peoples Gas to operate it with a longer injection season and a shorter withdrawal season than most aquifer storages. Injection has been 270 days and withdrawal 90 days. The chart below shows injections and withdrawals over the approximately 40-year life of Manlove Field.[365]

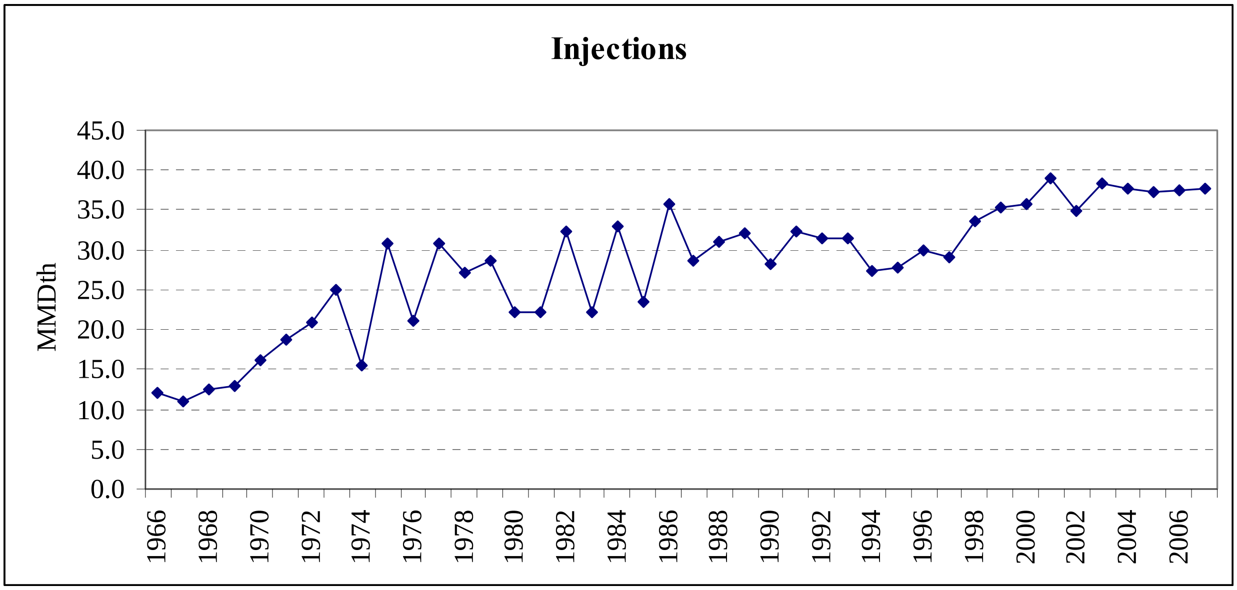
[364] Response to Data Request #112.
[365] Response to Data Request #112. The 2000 and 2002 years included two injection and withdrawal cycles rather than one, which have been combined for the purposes of this graph. Withdrawals for 2006 and 2007 and injections for 2007 are company estimates.

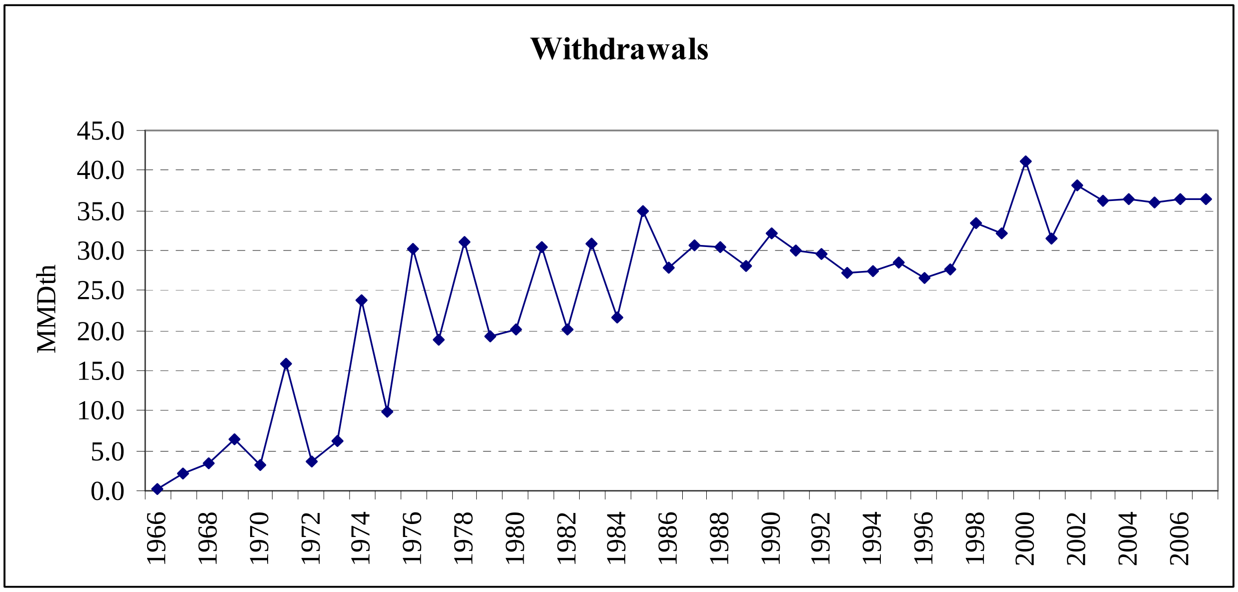


The overall pattern shows low withdrawals relative to injections in the early years, as Peoples Gas developed the reservoir and built up cushion gas. Overall, Manlove injections relative to withdrawals have not conformed to a clear pattern. The Peoples Gas reservoir engineers understood that Manlove's geological characteristics would not allow the field to respond well to rapid changes; optimal performance required consistency and slow changes.

The following two graphs depict Manlove injections and withdrawals separately, illustrating the lack of stability that existed until recent years.[366] Beginning with the 2003 injection season, Manlove's operating practices began to achieve consistency as Peoples Gas maintained injections and withdrawals at roughly stable levels, and implemented standardized annual inventory practices and verification. This increased level of stability, along with other operating improvements, began about the time of the appointment of the current Manager of Gas Storage.

[366] Response to Data Request #112. Withdrawals for 2006 and 2007 and injections for 2007 are company estimates.





b. Multiple Injection and Withdrawal Cycles

Aquifers in general, and Manlove in particular, are best operated with continuous injection and withdrawal cycles. The Commission explored this aspect of Manlove operations in the 2001 reconciliation proceeding. Citing Peoples Gas exhibits and testimony, the Commission found:[367]

> *Once withdrawals begin, they cannot be stopped. PGL personnel are not able to change from injections to withdrawals and back again. Therefore, if PGL is in its injection phase, Manlove can be unavailable for withdrawals during the months of October, November, March and April.*

The Order also noted that 2000 withdrawals began in late November, two weeks earlier than usual. This withdrawal proved problematic because it was determined that Peoples Gas withdrew

[367] ICC Order in Docket No. 01-0707, March 28, 2006, p.76.

more gas for third-party (Hub services) customers than had been injected for them. Thus, Peoples Gas had to go into the spot market during the winter of 2000/2001 for replacement supplies in order to maintain service to its on-system, or "Gas Charge" customers.[368]

Peoples Gas actually ran two injection and withdrawal cycles ("a" and "b") during the winters of 2000/2001 and 2002/2003. For purposes of analysis, Liberty combined the injections and withdrawals for the two cycles in each year. The tables below present the specific activity during those two years.[369]

Two-Cycle Injection and Withdrawal Activity 2000 - 01[370]

Year	Injection Volume (Bcf)*	Withdrawal Volume (Bcf)	Effect on Cushion (Bcf)
2000 (a)	20.6	3.9	
2000 – 01(b)	14.6	36.2	
2000 – 01 Totals	**35.2**	**40.1**	**(4.9)**

Two-Cycle Injection and Withdrawal Activity 2002 - 03

Year	Injection Volume (Bcf)*	Withdrawal Volume (Bcf)	Effect on Cushion (Bcf)
2002 (a)	19.9	1.9	
2002 (b)	14.7	35.7	
2002 – 03 Totals	**34.6**	**37.6**	**(3.0)**

Peoples Gas characterized the two-cycle years as "experiments," although noted that it did not conduct any trial in a structured or controlled manner. Liberty confirmed that there were no indications that Peoples Gas developed any substantial controls on conditions, implemented a structured test scenario, or evaluated results. As typified other activities related to Manlove and the Hub, no economic analysis preceded these changes, and Peoples Gas performed no economic analysis of results and no analysis of the physical impacts that those activities would have on reservoir behavior during the following years.

Peoples Gas employees have understood that Manlove is slow to respond to changes because of its geology. Proper management of the field has thus required that intentional changes be made

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[368] ICC Order in Docket No. 01-0707, March 28, 2006, pp. 76-79.

[369] Response to Data Request #14, *Calculation of Cushion and Non-Recoverable Gas*. Reservoir volumes are under high pressure, and the data here have been converted to standard surface operating system volumes.

[370] In comments on Liberty's Draft Report, the Company argues that these charts are misleading because they ignore the fact that targeted volumes were not withdrawn during the winters of 1999/2000 and 2001/2002, so the extra withdrawals in the summers of 2000 and 2002 were justified to get storage levels down to targeted levels. In fact, the Commission found in its 2001 Reconciliation Order (see pp. 83-94) that extra withdrawals for the Company's various schemes with Enron cost its customers money when the Company had to go into the spot market for gas supplies in December 2000 because there was not enough gas in storage. Similarly, while the winter of 2001/2002 was unusually warm, the winter of 2002/2003 (which is when the gas injected into storage during the summer of 2002 would have been used) was unusually cold toward the end, so extra stored volumes would have been especially valuable at that time. The withdrawal during the summer of 2002 almost certainly cost the Company's customers money, just like the one during the summer of 2000 did.

slowly and gradually, with careful measurement of their effects. The cycling of the field did not conform to that principle. After the 2000/2001 year, Peoples Gas concluded that:[371]

> *Field performance for the 2001-2002 withdrawal season has been reduced as compared to the previous withdrawal cycle. It is unclear if this trend will continue in future withdrawal seasons.*

The tables above also indicate removal of cushion gas during the two-cycle years, which is a suboptimal operating practice. After the 2002/2003 year, Peoples Gas concluded:[372]

> *Caution should be used when estimating deliverability in the upcoming withdrawal season.* ***Cushion removal, as was the case during the last withdrawal season,*** *[emphasis added] has historically resulted in a loss of field performance in the following withdrawal season.*

c. Gas Accounting

The readings recorded by the injection and withdrawal meters at Manlove have formed the basis for the gas, financial, and plant accounting records for the field, and have formed an important basis for capital and expense calculations. Physical inventory and related activity, on the other hand, did not use this metering data. Peoples Gas may have used physical-inventory activities as a "sanity check" for the metering data, but that data did not affect the total recorded volumes, except with respect to the allocation of gas to recoverable and non-recoverable cushion. Those allocation percentages resulted from physical testing and analysis conducted at Manlove and reported to Gas Accounting.

In 2000, Peoples Gas began a new physical inventory verification procedure; *i.e.*, the use of gamma ray/neutron surveys in a sampling of wells. A software program analyzes the survey data and determines gas saturation in the field. A second software program calculates the volume of gas in the storage field, using the results of that calculation and surface shut-in well pressures.[373] Reservoir Engineering compares the calculated physical inventory with book inventory, the latter based on the injection and withdrawal meter data. The table below shows the years in which Peoples Gas used this method, how many wells it sampled, the calculated and book inventories, and the differences.

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[371] Response to Data Request #14, *Decline Curve Determination 4/18/02, 4th page (un-numbered)*

[372] Response to Data Request #14, *Decline Curve Determination 3/21/03.*

[373] Response to Data Request #14, I2004 Inventory Report. The Well Data system software determines gas saturation and calculates cumulative gas-feet in the wells, and the Oil Field Manager software package estimates the volume of gas in the reservoir and converts it to surface pressures.

Comparison of Physical and Metered Inventory

Fiscal Year	Inventory Report Date	No. of Wells Tested	Calculated Inventory (Bcf)	Book Inventory (Bcf)	Difference (%)
1999	None	0			
2000	None	0			
2001	7/28/03	N/A	161.4	156.6	3.1
2002	None	0			
2003	None	0			
2004	12/23/03	18	171.6	163.2	5.2
2005	6/6/05	16	171.5	163.3	5.0
2006	12/23/05	11	165.8	164.0	1.1

Peoples Gas' reservoir engineers state that the differences (shown in the right-hand column) represent reasonable agreement, given the available measurement technology. Additionally, they have had a reservoir consultant review the results. The consultant concluded that the results were acceptable, finding that …*Typically error is in the range of 5 to 6 percent, but acceptable engineering tolerances could range as high as 10 to 15 percent. Any error higher than the stated engineering tolerance would trigger further studies to determine the cause of the discrepancy.*[374]

Some of Manlove's inventory practices have improved in the last several years, through a more consistent application or more sophisticated techniques. There still exists, however, no written documentation of policies, procedures, and practices.

d. Metering Error[375]

To inject gas into the Field, it is necessary to boost the pressure from Mahomet pipeline pressure (approximately 750 psi) to reservoir pressure (approximately 1750 psi). On-site compression fulfills that function. Injection volumes can be measured on the suction (input) side of the compressors, the discharge (output) side, or both. For many years prior to 1989, Peoples Gas used seven of its own orifice meters to measure gas injected into storage. In 1989, with the interconnection with Trunkline Gas Company, Trunkline added three turbine meters. The Peoples Gas and Trunkline meters were all AGA-compliant revenue-grade meters. The Utility continued to use them as the source of metered flow data reported to Gas Accounting until 1997. At that time, Peoples Gas installed low-cost, discharge-side Verabar meters to measure injection volumes at Manlove. Peoples Gas states that it installed the Verabar meters to simplify the metering arrangements for gas going into storage and to maintain the flexibility to receive gas for injection from multiple suppliers.[376] The Verabar meters were non-revenue grade (not approved for use for billing purposes) and non-AGA-compliant (not certified as meeting AGA performance criteria).

In November 2002, using a pipeline reconfiguration installed for other purposes, Manlove personnel simultaneously measured injection volumes on the suction side of the compressors with AGA-compliant meters, and noted a discrepancy between the readings on the suction and

[374] Response to Data Request #14, Connaughton Inventory Verification reports.
[375] Response to Data Request #14, memorandum, September 18, 2003.
[376] Response to DR 311.

discharge sides of the compressors. Peoples Gas hired a consulting firm in April 2003 to perform a study of the problem. The resulting study identified metering errors on both sides of the compressors, resulting from pulsations in gas flow introduced by the compressors. The pulsations, and consequently the metering errors, varied depending on which compressors were running at the time. The study also concluded that Peoples Gas could minimize the errors by using AGA-compliant meters on the suction side of the compressors, relocating data transmitters, and making certain operational changes in the running of the compressors.

Over a six-month test period during the 2003 injection season, (mid-March to mid-September), the suction-side meters recorded between 0.2 and 2.2 percent more gas than the existing Verabar discharge-side meters. The six-month average under-recording was 1.25 percent, or approximately 357,000 Mcf. Ultimately, Peoples Gas replaced the old Verabar meters with revenue-grade, AGA-compliant ultrasonic meters, which use an inherently more accurate technology and provide real-time diagnostics to monitor performance.

The metering error likely affected the Utilities' lost-and-unaccounted-for (LAUF) gas account, making it too large. That account affects Gas Charge customers, as those costs are recovered through the Utilities' purchased-gas charge. Liberty does not believe that the metering data could have been manipulated for other purposes, but recommends a careful accounting of where gas came from during this period, and where it went.

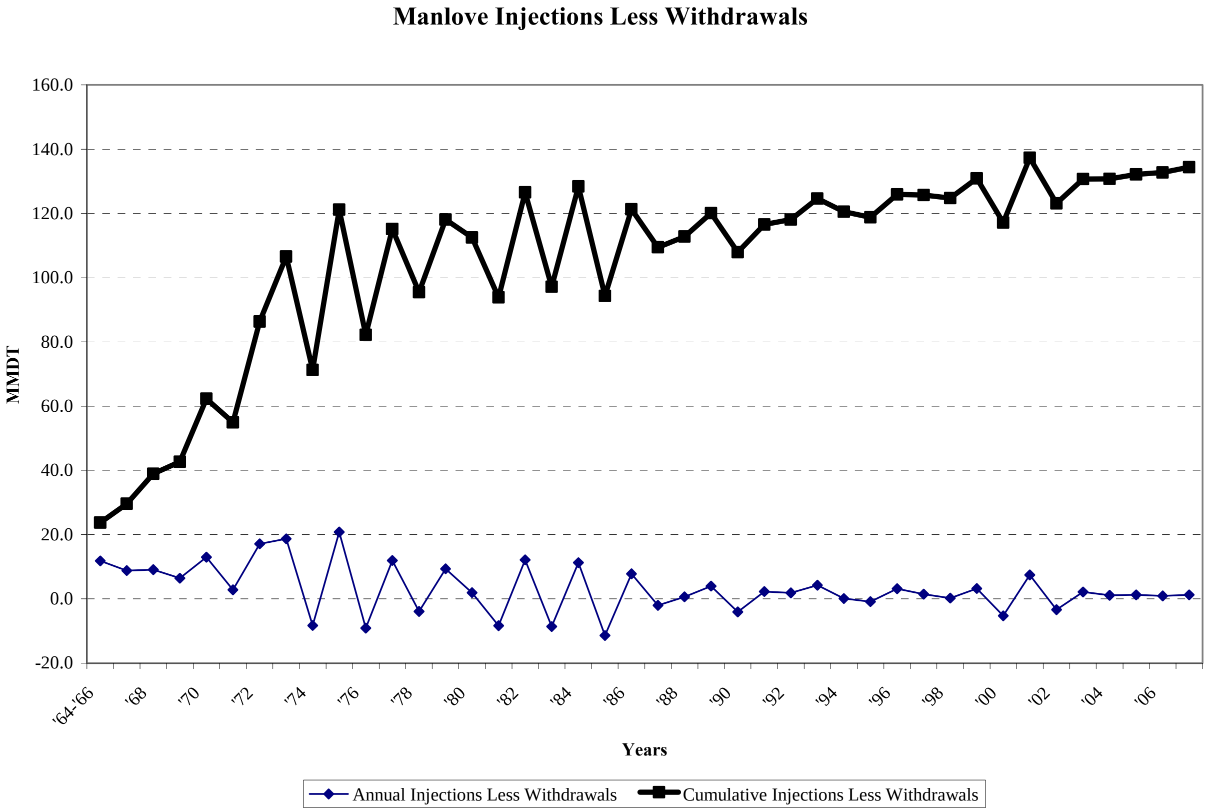
e. Non-recoverable Cushion Gas

For cost and gas accounting purposes, gas injected into underground storage is recorded into one of two categories: cushion gas (also referred to as "base" gas) and inventory gas (also referred to as "working" gas). Cushion gas represents a long-term investment necessary to operate the underground gas storage system, and is capitalized to Plant in Service and depreciated. Cushion gas builds up over the life of the reservoir, with high proportions of injected gas going to cushion in the early years, as the operator develops the reservoir, and gradually decreasing as the reservoir develops. Inventory gas is recorded on the books as Gas Stored Underground-Current, and represents the gas that Peoples Gas expects to be available for withdrawal during the next year.

Most of the cushion gas is considered non-recoverable. That is, if Manlove were to be abandoned, it would not be economically feasible to extract it from the reservoir. A small portion (3 to 4 percent) is considered to be recoverable, however, and would be able to be extracted economically. For those reasons, non-recoverable cushion gas has been treated as a depreciable asset (akin to other physical plant, such as wells and compressors), and recoverable cushion gas has been considered a non-depreciable asset (akin to inventory).

As time goes on, gas continues to migrate further into the rock formation, and the operator needs to inject additional cushion gas on a continuing basis to maintain storage field performance. These additional injections of cushion gas are sometimes referred to as "maintenance gas." Liberty understands that, prior to 1999, Peoples Gas would designate some of the injected gas as maintenance gas when reservoir performance declined, although not in a consistent fashion. Beginning in 1999, however, Peoples Gas designated a portion of each year's injected quantity as maintenance gas. From 1999 to 2005, that proportion was two percent.[377] In 2006, however, Peoples Gas increased the amount to three and one-half percent, as recommended by its reservoir consultant.[378]

The chart below depicts the annual difference between injections and withdrawals, and the cumulative difference between those two.[379]



The chart shows that by the end of FY2006 the cumulative difference between metered injections and metered withdrawals was 133.1 MMDth. However, the amount of gas that Peoples Gas capitalized as non-recoverable cushion at that time was 125.8 MMDth.[380] Peoples Gas has attributed the difference to a combination of the following factors:

- Working gas not yet withdrawn
- Recoverable cushion gas
- “Lost” gas.

Another reason for the difference is that, for a time, the cost of maintenance gas flowed through the Utilities’ purchased-gas-cost (PGA) account, rather than being capitalized and then

[377] See, *e.g.* the Direct Testimony of Staff Witness Dennis L. Anderson, dated June 29, 2007, in ICC Docket Nos. 07-0241 and 07-0242, at p. 24.
[378] Response to Data Request 14, Correspondence Connaughton to Puracchio and Kronas 9/30/05.
[379] Response to Data Request #112. Withdrawals for 2006 and 2007 and injections for 2007 are company estimates.
[380] Interview #24, February 8, 2007.

depreciated. During this time, the Utilities added maintenance gas, but recovered the cost of it currently. The 2001 Reconciliation Order of the Commission found this approach to be unfair to Peoples Gas' system-supply customers, and required the Utilities to return to capitalizing the maintenance gas.[381] As part of the settlement approved by that Order, the Utilities recorded no cushion gas injections for FY1998 through FY2000.[382]

f. Conversion of Inventory Gas to Cushion Gas

Peoples Gas' accounting treatment of cushion gas and inventory gas is consistent with industry practice. For most of the 1970s through the mid-1990s, however, the U. S. Internal Revenue Service (IRS) took a different position regarding cushion gas, considering it inventory. The distribution segment of the gas industry took the issue to the Tax Court, and ultimately prevailed. Because of the Tax Court decision, the IRS issued a ruling authorizing the treatment favored by the industry, which is the one currently in use by the Utilities. The ruling also directed the use of an automatic-change procedure that the IRS uses when a ruling is expected to result in a large number of change-in-accounting requests.[383]

For a number of years, the Utilities felt that they had overstated the amount of gas available as inventory gas. The reason was that a portion of this gas had migrated to cushion gas. However, previous IRS rulings had prohibited the reclassification of inventory gas to cushion gas, which was considered a capital expenditure to be depreciated. With the new ruling, the Utilities took advantage of the change to adjust their accounting to reflect their thinking regarding the recoverable/non-recoverable split. Working with the PEC's Tax and Accounting departments, Gas Supply hired a consultant to estimate the proper recoverable/non-recoverable split.[384] That study is the source of the 4 percent/96 percent relationship that the Utilities are currently using.

Peoples Gas filed an "Application for Change in Accounting Method" with the IRS on December 23, 1998.[385] It applied this change in January 1999 to both Peoples Gas and North Shore, which produced the following adjustments:[386]

[381] 2001 Reconciliation Order, at p. 9.
[382] Interview #35, May 8, 2007.
[383] In 1997, the IRS issued Revenue Ruling 97-54, reading as follows:

> *HOLDINGS*
>
> (1) *The cost of line pack gas or cushion gas is a capital expenditure under section 263.*
>
> (2) *The cost of recoverable line pack gas or recoverable cushion gas is not depreciable, but the cost of unrecoverable line pack gas or unrecoverable cushion gas is depreciable under sections 167 and 168. The Service will treat line pack gas or cushion gas as recoverable to the extent that such gas will be recovered from an abandoned pipeline or storage reservoir pursuant to a plan, a requirement of law, or economic feasibility, whichever method projects the greatest actual recovery of such gas.*

[384] Smedvig Technologies Roxar Report, dated December 1998, Response to Data Request #14.
[385] Effective for both book and tax purposes.
[386] Response to Data Request #238.

Peoples Gas:	**Volumes (Dth)**	**Amount ($)**
Inventory Gas	-11,482,156	-13,689,144
Recoverable Cushion Gas	-5,972,568	-5,701,445
Non-Recoverable Cushion Gas	17,454,724	19,390,589
Total	**0**	**0**

North Shore:	**Volumes (Dth)**	**Amount ($)**
Inventory Gas	-787,202	-906,541
Recoverable Cushion Gas	-548,570	-599,739
Non-Recoverable Cushion Gas	1,335,772	1,506,280
Total	**0**	**0**

This change affected PEC's financial statements. It increased the recorded amount for non-recoverable cushion gas. This change in turn resulted in higher annual depreciation charges, because non-recoverable cushion gas is depreciated for both book and tax purposes. Another impact of this change on PEC's financial statements was a corresponding decrease in the recorded amounts of inventory gas and recoverable cushion gas, which resulted in a lower working capital requirement related to gas inventory.

At the same time, Peoples Gas adopted the "Stiles" method for allocating cushion gas between recoverable or non-recoverable portions. Peoples Gas has applied that method since then, and calculated it retroactively back to 1990. Since the method was adopted, Peoples Gas has allocated cushion gas in the ratio of 96 non-recoverable to 4 recoverable.

5. The Decision to Enlarge the Field

A consultant's report in 1999 presented the results of a study examining the possibility of enlarging the storage field. [387] That study found that Peoples Gas could enlarge Manlove. Based on earlier studies,[388] the theoretical maximum was thought to be approximately 200 Bcf (working gas plus cushion gas). The study simulated field performance, and set out a possible expansion plan.[389] Peoples Gas states that its unwritten analysis at the time demonstrated that Peoples Gas' and North Shore's on-system customers could not use more than 25.8 MMDth of the field's capacity. Thus, if Peoples Gas expanded the field, it would have to find other markets for services that it could offer. The services that comprise the Hub serve those other markets.

Liberty made a number of requests, but Peoples Gas did not produce any studies to support a number of key considerations underlying its decision to enlarge the field, including:

- The stated maximum usage of 25.8 MMDth for on-system customers
- The economic viability of the Hub

[387] Response to Data Request #14, Effects of Increasing Seasonal Stored Gas Volumes on Reservoir Performance, July 1999.
[388] In comments on Liberty's Draft Report, the Utilities report that these studies were submitted to the Commission in response to FY05 Reconciliation Data Request No. POL-5.9.
[389] Interview # 36, May 9, 2007

- Peoples Gas prospects for successfully operating a business of that nature.

Interviews with Peoples Gas personnel produced the only basis that it put forth to support its belief that the Hub was a viable business proposition, which was that "Nicor had one that was generating a lot of activity."[390] Those personnel observed certain differences between the operation of Nicor's Hub and Peoples Gas', but Liberty found no indication of a business plan, no analysis of Peoples Gas' competitors for the services that it wanted to offer, and no assessment of the competitiveness of anticipated service offerings. The only concrete statement of objectives relating to the Hub was Peoples Gas' Letter of Intent with Enron, signed on the same day as the GPAA. That Letter of Intent envisioned cooperation with Enron in expanding Hub services. A business plan for the enovate partnership was developed in December 1999 and January 2000. That plan included expansion of Hub services as one of its objectives.[391]

Peoples Gas considers the development of the Hub to have been essentially without cost. Peoples Gas maintains that no additional physical plant was required in order to develop the Hub. Moreover, Because Peoples Gas provides much of the Hub services by displacement (as discussed later in this chapter) using spare capacity in all gas supply assets, the incremental operating costs are practically zero.

Consultant studies done for Peoples Gas plainly state that expansion of the field would require a significant addition of cushion gas.[392] As shown in the table below, actual injection and withdrawal data during the audit period show little net injections beyond the two percent per year identified as maintenance gas. In its recent rate case, Peoples Gas presented 7.88 MMDth as its estimate of additions to the cushion since the last rate case.[393] Given the requirement for continuing additions of maintenance gas, however, this amount appears inconsistent with a requirement for net injections of as much as 10 MMDth to support an expansion of the working-gas capacity of the Field by that amount.[394]

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[390] Interview #4, January 19, 2007.
[391] Interview #4, January 19, 2007.
[392] A 2003 study entitled "Manlove Field Trapped Gas Report" contains the following statements:

> *The current field inventory was about 161 Bscf at the end of 2002 injection. This is an increase of 20 Bscf over 1990. … Seasonal withdrawal volumes have increased from 30 Bscf to 38 Bscf. … [T]he 8 Bscf changes in withdrawal volumes … associated with the 20 Bscf of increased inventory clearly show that the increases in these performance parameters are less than half the inventory growth.*
>
> *The above observations are consistent with past estimates that 56% of gas that moves into virgin aquifer pore space is trapped or lost. Some growth will occur in pore volumes already containing gas, and a much smaller fraction of that gas will be lost. However, most continued growth will invade virgin aquifer with lost gas on the order of 50%.*

This study was provided to Liberty in response to Data Request #14. The quoted passage is at p. 1.
[393] This figure was reference in the testimony of Staff Witness Dennis Anderson (ICC Staff Exhibit 10.0), at p. 5.
[394] Comparing the Company's number for net injections with a) the continuing requirement for maintenance gas, and b) a need for additional cushion gas to support the expansion is complicated by factors like 1) varying amounts of maintenance gas over the period, and 2) varying rate treatment for cushion gas over the period. (Maintenance gas was flowed through the company's purchased-gas cost accounts for a time.) As discussed below, Liberty recommends a careful analysis of Peoples Gas' inventory and cushion-gas accounts in an attempt to reconcile the various adjustments.

Injections and Withdrawals During Audit Period[395]

Year	Injections	Withdrawals
1999	35.3	32.1
2000	35.8	41.1
2001	38.9	31.4
2002	34.8	38.2
2003	38.4	36.3
2004	37.6	36.5
2005	37.2	36.0
2006	37.4	36.5
Totals	**295.4**	**288.1**
Cushion Loss @ 2%/Year	(5.8)	
Net	**289.6**	**288.1**

Peoples Gas has not identified the additional cushion gas necessary to support expansion of the Field; however, it has recently increased the proportion of injected volumes designated as maintenance gas, from two percent to three and one-half percent. This incremental requirement for maintenance gas applies to the entire field, not only to the 10.2 MMDth of working-gas capacity used for the Hub, but also to the 26.3 MMDth used to provide gas supply and storage services to Peoples Gas' customers for utility services. If the extra one and one-half percent charged to utility-service customers is caused by the Hub's need for cushion gas, to make up the 10 Bcf of additional cushion required for the expansion, then Hub operations are being subsidized significantly by utility customers.

6. FERC-Jurisdictional Services/Hub Services

The Peoples Gas Hub provides two types of services:

- Those specifically certificated by the FERC and provided pursuant to the Peoples Gas Operating Statement
- Others provided pursuant to blanket certificate authority from the FERC.

The latter category includes balancing and transportation services that Peoples Gas provided to Nicor,[396] and miscellaneous short-term transportation services provided to other customers. Hub revenue statements provided to Liberty also reported transportation for a peaking service provided to Nicor by affiliate Peoples Natural Gas Liquids (PNGL),[397] but that service is provided pursuant to an ICC-approved contract.

The table below shows the revenues generated by each of the different services for each of the years of the audit period. The table shows steady growth in revenues from FY1999 through FY2002, but some variation in revenues since that time. By FY2006, the major revenue-

[395] Response to Data Request #112.
[396] These services terminated after FY2005.
[397] PNGL is a subsidiary of PERC.

producing services were park-and-loan (PAL), exchanges, and interruptible storage (IS). Peoples Gas' "budget" revenue estimate for Hub services is "about $10 million."[398]

Hub Services Revenues

Year	Park & Loan	FS	FT	IT	IS	Subtotal, Certificated Services	Exchange	Blanket-Certificate Services	Total
1999	$152,694	$182,500	$361,985	$3,863	$0	$3,659,391	$2,958,349	$0	3,659,391
2000	1,920,355	178,500	487,500	417	0	4,362,337	1,775,164	1,992,196	6,354,533
2001	1,152,401	0	636,252	39,388	0	3,998,584	2,170,543	2,848,376	6,846,960
2002	4,660,727	0	1,038,310	298,429	0	8,769,718	2,772,252	2,888,464	11,658,182
2003	5,307,672	0	1,463,100	142,145	0	8,743,220	1,830,303	2,658,463	11,401,683
2004	2,912,540	114,950	885,494	163,934	0	4,970,293	893,375	2,893,162	7,863,455
2005	4,541,804	90,250	629,064	123,660	205,847	6,969,235	1,378,610	3,266,686	10,235,921
2006	6,167,634	0	9,895	330,181	1,069,565	9,261,290	1,684,015	866,790	10,128,080

The next table shows the proportions of total revenues from key counter-parties in each year.[399] The data show that Nicor and affiliate PERC/PEWM have been important contributors to Hub revenues in most years. In FY2006, new affiliate[400] WPS Energy took over as the Hub's largest customer.

HUB Revenues from Key Counter-Parties

User	Nicor entities[401]		PERC/PEWM/PNGL/enovate		WPS Energy	
Fiscal Year	Amount	% of Total	Amount	% of Total	Amount	% of Total
1999	(no data)		(no data)			
2000	$1,439,500	22.7				
2001	2,175,304	31.8	$241,605	3.5		
2002	2,504,978	21.5	1,000,168	8.6	$67,604	0.6
2003	3,121,338	27.4	1,641,575	14.4	1,089,120	9.6
2004	2,524,717	32.1	1,074,675	13.7	842,904	10.7
2005	3,026,105	29.6	1,735,923	17.0	999,229	9.8
2006	534,080	5.3	928,600	9.2	2,033,520	20.1

Enron Midwest provided another $0.9 million in FY2001 and $2.2 million in FY2002. Observations that emerge from a review of Hub revenue summaries include the following:

- The most productive service in terms of revenue generation has been park-and-loan service (PAL). WPS Energy was the top customer for that service in terms of revenue in FYs 2003, 2004 and 2006; it was the second-largest customer for that service in FY2005.
- Oneok was the largest customer for exchange service, which was the second-largest generator of revenue, in FYs 2003, 2004 and 2006; it was the second-largest customer for that service in FY2005. Occidental Energy Marketing, which bought out the last two and

[398] Response to Data Request #166.
[399] Responses to Data Requests nos. 116 and 246.
[400] In comments on Liberty's Draft Report, the Utilities point out that WPS Energy did not become an affiliate until FY2007. The transaction was announced during FY2006, however, and opportunities for synergies were likely being explored before the formal closing of the transaction.
[401] Nicor, Nicor Enerchange

one-half years of the GPAA contract, and which with Oneok entered successor contracts with Peoples Gas, has been only an occasional Hub customer, for PAL service.

- Nicor had consistently been the largest customer for blanket-certificate services (the third-largest revenue-generator) through FY2005, after which revenues from those services dropped precipitously. The services provided to Nicor were 60 to 65 percent balancing, and 35 to 40 percent transportation in terms of revenues generated.
- Affiliate Peoples Energy Wholesale Marketing (PEWM) was one of only two customers for interruptible storage service (IS). The only other customer for that service was Peoples Gas supplier Tenaska Marketing Ventures, which provided about 25 percent of the revenues for that service in FY2006.

7. Hub Relationship to Utility Operations

An important focus of Liberty's examination was the relationship of Hub operations to utility operations, particularly Peoples Gas' operation of the Manlove Storage Field. Liberty first asked for copies of any written procedures that describe its gas-supply operations, including operations of the Hub. There were none. Thus, in an effort to understand the use of Manlove Field in those operations, Liberty observed a Morning (operations) Meeting, and followed up that observation with additional data requests and interviews.

Gas Storage and Gas Control are operating units within the Gas Supply department. Gas Supply manages all gas-supply resources, both owned and contracted. Gas Storage and Gas Control recommend, but Gas Supply decides.

At the beginning of each injection or withdrawal season, Gas Storage prepares a plan. That plan reflects Gas Storage's preferred operation for the season, taking into account the beginning storage level, maintenance schedules, and any other factors that might influence the plan. Preferred operation of the Field involves continuous injection of quantities to be stored, and continuous withdrawal. Thus, the seasonal plan can be readily divided into monthly and daily plans.

Each day's Morning Meeting begins with Gas Storage's preferred plan for injection or withdrawal on that day. It also begins with Gas Control's estimate of sendout to Peoples Gas' and North Shore's on-system sales and transportation customers for the next six days. Other inputs include: (1) Gas Supply's estimate of its commitments to Hub customers, and (2) an estimate of the difference between what Peoples Gas thought that the Utilities' transportation-service customers were going to do the previous day, and what they actually did, as confirmed by the interstate pipelines and the Utilities' gas-transportation tracking system. That difference is an essential input for each day's planning, as Peoples Gas' and North Shore's tariffs allow their transportation-service customers to inject or withdraw gas into individual "Gas Bank" accounts on a day-to-day basis.[402]

[402] In comments on Liberty's Draft Report, the Utilities point out that Gas Bank injections and withdrawals are entirely no-notice. If deliveries exceed consumption, there are injections, and if consumption exceeds deliveries, there are withdrawals.

At the Morning Meeting, Gas Supply takes the inputs provided by Gas Storage and Gas Control, and makes two sets of decisions:

- How much gas to take from each available source, including spot purchases that day, in order to satisfy the requirements of system-supply customers
- Whether, given its obligations to its different groups of customers (system-supply customers, transportation-service customers and Hub customers) Peoples Gas has any uncommitted capacity to move (including exchange and transportation) or store gas on that day.

In addition to the inputs from Gas Control and Gas Storage, Gas Supply considers the results of computerized optimization analyses. Those analyses use as inputs all owned and contracted capacity data, estimates of requirements and flow amounts from all customer segments, committed supply sources, and market-price information.

The Morning Meeting produces two products:

- Determination of the amount of additional gas to buy or sell that day, and from where, monthly and seasonal purchases having already been made.
- Confirmation or adjustment of the quantity of gas to be injected into, or withdrawn from, all storages, including Manlove Field. Depending on forward prices and capacity availability, this decision could include buying extra gas for injection into storage, or withdrawing extra gas from storage.

Manlove Field has discrete injection and withdrawal periods, because it cannot readily switch from one to the other during a season. Accordingly, any adjustment for it can only be in the rate of injection or withdrawal. Several of the Utilities' leased storages are "no-notice" services, however. Thus, Peoples Gas can either inject or withdraw as necessary for balancing supply with requirements each day.

Another product of the Morning Meeting is identification of that capacity at Manlove and the Utilities' other owned and contracted supply resources that Peoples Gas can make available for additional Hub services that day. Existing Hub commitments are taken into account prior to this assessment. After the Meeting, the Gas Supply personnel try to market any available capacity.

Peoples Gas uses all supply resources (pipeline, storage, and peaking resources, owned and contracted) in the provision of all supply services, to on-system and off-system customers, including Hub customers. As discussed in the next section of this chapter, the Hub's rates are based on the costs of the share of Manlove Storage Field's capacity designated for use by the Hub (10.2 MMDth/36.5 MMDth, or 27.9 percent) plus an allocated share of the costs of the Mahomet Pipeline. Physical delivery of Hub services, however, like physical delivery of all other services to all other customers, is accomplished by using all supply resources.

Peoples Gas stated its formal position on what facilities are included in the Hub as follows:[403]

> *Peoples Gas' Operating Statement, filed with and approved by the FERC, provides that transactions occur on Peoples Gas' "System". The Operating Statement defines the "System" as Peoples Gas' "local distribution system,*

[403] Response to Data Request #305.

> *storage field, transmission pipeline and other facilities owned and operated by Transporter [Peoples Gas] and subject to regulation by the Illinois Commission." The facilities actually used to provide Hub services and to develop the rates are limited to the Mahomet Pipeline and Manlove Field. With respect to the Mahomet Pipeline, all parts of that pipeline are included. With respect to Manlove Field, up to 10.2 Bcf of underground working gas capacity, undifferentiated from the remaining 26.3 Bcf of working gas capacity, is included along with the piping, valves and compressors necessary to inject and withdraw the working gas and which connects to the Mahomet Pipeline.*

Liberty construes this statement fundamentally as addressing cost allocation. A concession that all facilities, including the leased storages, are used in providing Hub services, could lead to a requirement to allocate 27.9 percent of the costs of the leased storages to the costs of providing Hub services. In that case, the Hub would be uneconomic. Liberty's belief that all gas-supply resources are involved in the provision of Hub services follows from the understanding of the physical aspects of providing those services. Liberty believes that all gas-supply resources, owned and leased, are physically involved in the provision of Hub services. Liberty believes (as is discussed more fully below) that Hub economics should be evaluated on the basis of marginal revenues and marginal costs. If marginal revenues exceed marginal costs, (Liberty believes that they do), then at least some Hub operations should continue. Nevertheless, each Hub service needs to be evaluated to determine whether the marginal revenues provided by that service exceed the marginal costs of providing it.

8. Accounting and Economics Issues

a. Hub Fully-Allocated Costs

The tables that follow, taken from Peoples Gas' FERC filings in 2000, 2003, and 2006, present the costs that Peoples Gas attributes to the Hub. Those costs comprise a proportionate share of the costs of the storage field, and a proportionate share of the costs of the Mahomet Pipeline. Peoples Gas prepares these filings, as required by the FERC,[404] to determine the maximum rates it can charge for the various services that the Hub offers. The costs represent all costs associated with owning and operating the pipeline and the storage field, including allocations of Peoples Gas Administrative and General expenses. In fact, however, Peoples Gas sells virtually all of its Hub services at discounted rates, subject to these maximums.

The Hub's share of the pipeline is 24.3 percent, or $2,791,902, using the numbers from the most-recent filing (2006). That share is determined by dividing the peak-day capacity available to the Hub (565,790 MMBtu) by the total peak-day capacity (2,325,000 MMBtu). The total peak-day capacity of the pipeline is determined in a peak-day flow modeling exercise conducted by Gas Control. The capacity available to the Hub is determined by subtracting all other commitments from that total capacity.[405]

[404] Response to Data Request #188.
[405] Response to Data Request #232.

Similar logic applies to assigning a share of the costs of storage capacity at Manlove Field. Peoples Gas lists total working-gas capacity of the field as 36,510,000 MMBtu.[406] It specifies the capacity available to the Hub as 10,200,000 MMBtu.[407] Thus, the Hub's share of the costs of the storage field is 10.2/36.5, or 27.9 percent. Applying that proportion to the total cost of service yields $10,490,893.

The Hub's share of pipeline and storage capacity together was the sum of $2,791,902 and $10,490,893, or $13,282,795 in 2006. A comparison of this number with the revenue information in the "Hub Revenues" table above suggests that the Hub has yet to generate revenue close to equaling its fully allocated share of Mahomet and Manlove costs. The Hub has, however, produced revenues that exceed its share of identified Operation and Maintenance expenses, which totaled $3,422,675 for 2006.[408] Hub revenues have exceeded this amount for the entire audit period, and by a large margin since FY2000.

Transmission Cost of Service & Rate Derivation for FT & IT Service:

	06/30/2000	**06/30/2003**	**06/30/2006**
Operation Expenses	$1,211,492	$1,169,243	$1,996,023
Maintenance Expenses	848,651	510,749	377,044
A&G Expenses	775,678	1,147,897	1,230,381
Depreciation	1,876,617	1,287,405	1,151,389
Other Taxes	420,360	344,080	401,820
Income Taxes	1,856,168	1,804,539	1,826,934
Return	4,575,886	4,448,609	4,489,169
Total	**$11,564,852**	**$10,712,522**	**$11,472,760**
Billing Determinants (MMBtu)	500,000	500,000	565,790
Annual Cost per MMBtu	$23.1297	$21.4250	$20.2774
Monthly Cost per MMBtu	$1.9275	$1.7854	$1.6898
100% Load Factor Cost per MMBtu	$0.0634	$0.0587	$0.0556

406 Response to Data Request #188.
407 Response to Data Request #59.
408 (.243)*($1,996,023+377,044) + (.279)*($7,768,388+2,432,401) = $3,422,675.

Storage Cost of Service & Rate Derivation for FT & IT Service:

	06/30/2000	06/30/2003	06/30/2006
Operation Expenses	$3,986,582	$4,785,211	$7,768,388
Maintenance Expenses	4,769,668	2,384,410	2,432,401
A&G Expenses	3,296,875	4,898,827	5,288,872
Depreciation	8,492,195	4,184,504	3,185,704
Other Taxes	928,200	961,500	1,162,057
Income Taxes	5,236,975	4,317,143	5,120,746
Return	12,910,364	10,642,764	12,582,771
Less Amounts Billed to North Shore	-1,924,442	-1,382,779	-1,716,712
Total	**$37,696,417**	**$30,791,580**	**$35,824,227**
Billing Determinants (MMBtu)	1,017,363	1,017,363	993,464
100% Load Factor Cost per MMBtu	$0.0511	$0.0410	$0.0470

b. Hub Marginal Costs

The Hub may not be covering a share of fully allocated Mahomet and Manlove costs; however, it clearly covers the marginal costs of operating it, and provides a considerable contribution to recovery of other costs. Even if the test were whether the Hub was covering the cash costs of continued operations, which Liberty defines as a proportionate share of Manlove Maintenance expense, plus a proportionate share of maintenance gas, Liberty concludes that the answer is "yes" based on the following logic:

- The Hub's share of maintenance gas is (10.2 divided by 36.5) times (36,500,000 MMBtu times 0.02), which equals 204,000 MMBtu. If that amount of gas was expensed currently, rather than capitalized and depreciated, the cost would be $1,801,320 at Peoples Gas' FY2006 gas price of $8.83 per MMBtu.
- The Hub's share of storage fuel and power expense is (10.2 divided by 36.5) times ($4,970,904),[409] which equals $1,389,129. There is no fuel and power expense for transmission, as most Hub movements occur by displacement.
- Thus, the total amount of the Hub's share of these expenses is $1,389,129 plus $1,801,320, which equals $3,190,449.

Increasing the proportion of injections required for maintenance gas from two percent to three and one-half percent, as has recently been implemented by Peoples Gas, would raise this cost to $3,152,310. At this higher level, the total cost of the Hub's share of the two cash expense items would rise to $4,541,439, which is still well below the Peoples Gas $10,000,000 budgeted level of Hub revenues. This calculated cost also falls well below the lowest level of Hub revenues that Peoples Gas has realized in the last five years.

The open question is the cost of the base gas required to support Hub operations. As noted earlier, the Company has argued that none is required, but has also increased the maintenance gas proportion. If the Hub were required to cover the cost of the extra maintenance gas now

[409] Response to Data Request #188. The values used are for the 12 months ended June 30, 2006 (Schedule H).

charged to on-system customers, the additional cost would be $3,483,435.[410] Adding this cost to the Hub's share of the two cash expense items would increase the total to $8,024,874. That amount is still less than the Hub's budgeted revenue, but the difference would become considerably less.

c. Costs of Hub versus Utilities Leased Storages

The Hub has generated marginal economies. There nevertheless remains the question of whether operation of the Hub is the best use of the extra capacity in the pipeline and Manlove Field. Put another way, a proper inquiry is whether Peoples Gas and North Shore customers would be better off if the Utilities were to replace all or a portion of their off-system storages with the capacity currently used for Hub operations.

A first step in answering that question is to compare the costs of the Manlove capacity used for the Hub to the costs of the other off-system storages leased by the Utilities. Peoples Gas submits the cost studies referenced above to the FERC for determining the maximum rates that the Hub can charge for its firm services. Those studies indicate what Hub rates would be if the Hub was bearing a proportionate share of the costs of the pipeline and the storage field. The following table indicates how those costs compare to the costs of the storages that Peoples Gas leases as part of the capacity portfolio that it uses to provide service to its customers.

Comparison of Hub Storage Rates with Off-System Storage Rates

Storage Rates	Manlove	ANR NSS Service	NGPL NSS Service	NGPL DSS Service
Demand ($/Dth/month)	1.3823	3.40	3.0700	5.3333
Capacity ($/Dth/month)	0.0395			
Commodity ($/Dth)	0.0003	0.015		
Storage-related Transportation				
Demand ($/Dth/day per mo.)	1.6898	2.8140	0.3057-1.8343	
Commodity ($/Dth)	0.0556	0.0075		

Another step in evaluating the possibility of substituting the additional Manlove capacity for one of the leased storages is to examine whether it would fit Peoples Gas' operational requirements. Peoples Gas has stated that such substitution would not fit; however, it has not provided any analysis of this possibility.[411] This question has importance because the preceding table suggests that the Manlove capacity is less costly than the leased storages.

[410] (.015)*(26,300,000 MMDth)*(8.83) = $3,483,435.
[411] Response to Data Request #285.

C. Conclusions

1. Peoples Gas' failure to develop and follow operational policies and procedures for Manlove Field is not consistent with good utility practice. *(Recommendation VII-1.)*

Peoples has not developed policies or procedures controlling important operational and accounting matters, such as physical inventory, frequency of performing the physical inventory, reconciling physical inventory with metered inventory, identifying and quantifying losses, determining the amount of cushion gas to be capitalized and expensed, and injection and withdrawal plans. Peoples Gas points out that it operates the field with the benefit of 40 years of experience. Peoples Gas should institutionalize the benefit of that experience by preparing policies and procedures that interpret and record that experience for the benefit of future operations.

2. Peoples Gas has not ensured that ratepayers have had priority access to Manlove Field and that those assets have been used to benefit ratepayers, rather than Hub customers and non-utility affiliates. Peoples lack of policies and procedures for scheduling Hub transactions and for scheduling injections and withdrawals from the Manlove Field is a significant contributor to this deficiency. *(Recommendation VII-1.)*

Peoples Gas has used the same unwritten and undocumented process to manage injections and withdrawals for system-supply customers and to schedule Hub transactions. A group of experienced people has gathered daily to seek the best available solution to a complex optimization problem. They have come to the Morning Meeting with the best available estimates of a number of key unknowns, and with the support of several quite sophisticated analytical tools.

There has been neither a clear policy framework nor documented policies and procedures to govern the scheduling optimization process and its implementation. Peoples Gas personnel acknowledge the primacy of the interests of utility-service customers; however, Peoples Gas has not formulated those statements into tangible objectives. There has been no clear statement of the objectives of the optimization, nor has there been any statement of priorities among the objectives in the event that multiple objectives conflict. The FERC Operating Statement also provides no guidance or direction on these matters.

With three different sets of customers—retail, transportation, and Hub—being served from one set of gas-supply assets, it has been possible, if not likely, that those gas-supply assets were being managed to maximize revenue, rather than being managed to minimize costs to one of the three sets of customers. It was also possible, and perhaps likely, that creating opportunities for unregulated affiliates comprised another objective of the optimization process. Use of the Hub by the Utilities' unregulated affiliates, as measured by revenues, has increased markedly over the audit period.

The lack of documented procedures makes it impracticable to audit the optimization process. Peoples Gas personnel say that each day's Morning Meeting has sought the optimal result for utility service customers, but there has been a lack of tangible measures for demonstrating that their actions accord with that goal. Clearly, the over-withdrawals for the benefit of Enron demonstrate that it is indeed possible to optimize for other purposes. Further, Peoples Gas has operated Manlove as a swing facility rather than a base-load facility, even though Manlove Field management was well aware that such operation is suboptimal, given that Manlove is an aquifer storage field, and a poorly performing one relative to other aquifer storages.

3. Reporting and control responsibilities for Manlove Field are fragmented in the Peoples Gas organization. *(Recommendation VII-2.)*

Various, disparate organizational units have had responsibility for directing or monitoring and tracking the various operating parameters of Manlove. For example:

- Gas Supply and Gas Control – specify dates and volumes of injections and withdrawals[412]
- Gas Storage – manage physical operations and physical inventory verification
- Gas Accounting – record and track inventory levels and cushion allocations
- Financial Accounting – record and track cost of gas
- Plant Accounting – handle depreciation of cushion gas.

The distributed responsibility for Manlove has been weakened by the fragmented reporting relationship. While the Manlove Field organization demonstrated reasonable knowledge, experience, and understanding of the field operations, they were physically remote from headquarters, and the headquarters personnel to which they reported did not have experience in storage or transmission operations.

4. The levels of inventory and cushion gas, and recoverable and non-recoverable cushion gas at Manlove are uncertain. *(Recommendation VII-3.)*

A number of factors and actions, some deliberate, some resulting from the physical characteristics of Manlove Field, and some resulting from the deficient management of Manlove Field, have contributed, on a cumulative basis, to a situation in which the levels of inventory and cushion gas at Manlove are uncertain. Those factors include:

- A requirement for approximately 10 Bcf of additional cushion gas to support expansion of the Field, which has not been accounted for.
- The inconsistent levels of injections and withdrawals over time, which Peoples Gas did not rationalize on an ongoing basis. Between 1999 and 2003, physical inventories were only performed in one year, 2001, providing no physical verification against metered inventories.
- Metering error which produced an under-recording estimated at 1.25 percent, or 357,000 Mcf over a six-month period in 2003. Applying that level of error over the six-year period and six injection cycles that the under-recording meters were in place would represent a total of approximately 1.8 Bcf of gas injected but not metered. Assuming gas cost at $5 per Mcf, this could represent an unaccounted-for cost of $9 million. That number is conservative because Manlove actually uses nine-month injection cycles rather than the six months for which data is available.

[412] These decisions are made in consultation with Gas Storage, but Gas Supply has the final word.

- The mismatch between book and physical inventories that existed for many years, but was not addressed due to tax considerations.
- The annual allocation to cushion gas from time to time based upon reasons ranging from best estimates to outright manipulation. An example of the latter was when Peoples recorded zero maintenance gas (a term Peoples used for injections of cushion gas) and instead treated it as lost and unaccounted for gas. That issue was dealt with as part of the settlement with the ICC to remedy it and other problems.

Liberty found that the number of adjustments, their varying direction (up or down), their varying rate treatment (rate-base or PGA recovery), and their interaction with other parameters that have been the subject of measurement questions (*e.g.*, LAUF) indicate significant uncertainty as to the inventory and cushion volumes of gas in Manlove.

5. Peoples Gas made major decisions about the Hub and Manlove Field without the benefit of sound, documented analysis. *(Recommendation VII-4 and -5.)*

Among the decisions were those to create the Hub, to expand the Hub and Manlove Field, to operate Manlove Field as a swing rather than base-load facility, and for cycling it twice in two different years. Manlove Field issues did undergo occasional focused outside studies, but there was no careful, documented analysis of major decisions by Peoples Gas staff. The explanations offered in interviews by Peoples Gas personnel (for example, that cycling Manlove twice during the 2000-01 and 2002-03 years was an experiment, and that the Manlove expansion was analyzed but undocumented) are no substitute for contemporaneous, comprehensive analysis and reasoned decision-making.

The dispersal of authority and responsibility for the Hub and Manlove Field has been a major, although not the only, contributor to this problem. For example, Liberty found several individuals who reported that they advised against expanding the field, but no one who took any responsibility for the expansion decision.

Peoples Gas provided no analysis of its decision-making at the time that the expansion began. Peoples Gas states that the decision was made by its senior management and officers; however, Liberty found no record of who had final authority over the decision, or what if any analysis on which that decision might have been based.

The Manlove expansion required significant field-enlargement costs. In particular, Peoples Gas had to inject approximately 10 Bcf of cushion gas to support a 10 Bcf expansion. Assuming a cost of gas of $5 per Mcf, the expenditure would have approximated $50 million. Liberty would expect to see an economic feasibility study that includes that cost and a reasonable payback period. It appears that the cost of the 10 Bcf was simply not considered in the decision-making process.

6. Overall, the long-term, substantial weaknesses in management and operations of Manlove Field and the Hub resulted in significant controls weaknesses. *(Recommendation VII-1, 2, 3, 4, 5.)*

In summary, Liberty found the following conditions to exist:

- A lack of policies and procedures to operate Manlove Field
- A lack of policies and procedures to operate the Hub
- A lack of policies and procedures for scheduling Hub transactions
- Fragmented authority and responsibility for the management of Manlove Field and the Hub
- Uncertain levels of inventory and cushion gas at Manlove
- Physical inventories rarely taken at Manlove Field until recent years
- Significant, long-term metering error at Manlove Field
- Large volumes of gas unrecorded and unexplained (resulting from metering error and cushion gas to support the expansion)
- Suboptimal operation of Manlove Field, as a swing rather than base-load supply
- Major decisions unsupported by reasoned, documented analysis.

These attributes created an environment in which sub-optimal (from a Utility cost perspective) actions or results could happen under circumstances that would make them difficult to detect. As described above, assuming a gas cost of $5 per Mcf, the cushion gas to support the Manlove Field expansion and the metering error represent approximately $50 million and $9 million, respectively in unexplained gas costs.

7. Hub activities provide sufficient net benefits to justify continuing to offer the services at some level.

Liberty concluded that although the Hub is not covering its fully allocated costs, at an overall level it is covering its marginal costs and is making a contribution to fixed–cost recovery. This provides reasonable justification for continuation of Hub operations at some level. However, as pointed out in a subsequent conclusion, this assumes that the Hub facilities are not better used to supply ratepayers, which has yet to be explored. Moreover, it is not clear that individual types of Hub transactions cover their incremental costs and make a contribution to fixed–cost recovery.

This conclusion does not necessarily indicate that the decision to expand Manlove and the Hub was an economically supportable decision. That decision has yet to be explored. However, for purposes of deciding whether to continue Hub operations, that decision is moot.

8. Peoples Gas does not know the margins contributed by individual Hub services. *(Recommendation VII-6.)*

The nominal facilities used to provide Hub services are the additional storage capacity at Manlove and available capacity in the Mahomet Pipeline. If capacity is available, however, Gas Supply also sells capacity in Peoples Gas' leased storages as Hub services.

Hub services are often provided by displacement. The table below, compiled from the same schedule (Schedule G) in succeeding reports by Peoples Gas to the FERC regarding Hub operations, shows that Hub customers withdraw gas from storage every month of the year, even though Manlove is in withdrawal mode for only three months of every year. Withdrawal for Hub customers in months when Manlove is not in withdrawal mode is accomplished by re-routing gas that was going elsewhere; *i.e.*, by displacement.

Storage Withdrawal and Loan Activity[413]
(Dth)

	2002/2003	**2005/2006**
July	2,507,518	222,387
August	677,331	137,991
September	207,007	426,065
October	1,561,175	521,464
November	820,029	645,515
December	2,353,858	2,493,867
January	3,670,414	3,726,026
February	3,849,786	2,180,711
March	1,454,193	583,653
April	666,737	191,611
May	178,770	187,277
June	238,848	77,958
Total	18,185,666	11,394,525

Providing Hub services by displacement effectively allows Peoples Gas to make spare capacity in all facilities available for provision of Hub services. Indeed, in the Morning Meeting, all facilities are treated as part of an integrated system, and it is the system as a whole that is assessed every day for available capacity.

In the post-settlement regulatory regime, this practice is reasonable and appropriate. Now that Hub revenues are credited to purchased-gas costs, Hub services are, in principle, analogous to capacity releases or off-system sales. Capacity releases and off-system sales are provided from capacity that is required to be available in order for the Utilities to meet their service obligations, but is temporarily not needed to meet those obligations. Such capacity is sold into secondary markets by gas distribution companies and others in an effort to recover part of its cost. Peoples Gas' owned and contracted capacity has been augmented by expansion of Manlove Field. That augmented capacity is what is being made available for Hub services, through a process that Liberty sees as analogous to capacity releases and off-system sales.

Hub revenues are credited to purchased-gas costs; therefore, whether a particular Hub service helps or hurts customers for utility service is determined by whether the revenues generated by that service exceed the incremental costs of providing it. It is clear that Hub revenues as a whole exceed the incremental costs of providing them. However, the question of whether each individual Hub service covers the cost of providing it is not addressed, since Peoples Gas has not calculated the incremental costs of each service. The FERC rates offer little guidance in this regard, as Peoples Gas rarely charges maximum rates, and the FERC-approved minimum rates for some services are zero.

[413] Response to Data Request #188.

9. Peoples Gas may be retaining a higher level of leased storages than necessary in order to justify continuing Hub activities. *(Recommendation VII-7.)*

Now that Hub revenues are credited against Gas-Charge costs, Liberty finds Hub services to be effectively the same thing as secondary-market activities, in which virtually every gas distribution company is engaged. Liberty's concern with Hub services is similar to a standing concern about all secondary-market programs, namely, whether gas supply assets that are not required for the provision of services to ratepayers are being retained in order to have more capacity to sell into secondary markets.

In the case of Peoples Gas, the potential excess capacity is in the leased storages. Transmission and storage capacity at Mahomet and Manlove, respectively, appear to be less costly than the leased storages. The question then is whether some or all of the expanded capacity at Manlove can be substituted for some of the leased storages. If so, then the amount of leased storage can be reduced.

If the amount of leased storage is reduced, the amount of capacity potentially available for Hub activities will be smaller. In that event, Peoples Gas can assess whether additional Hub revenues might justify retention of the extra leased storage.

D. Recommendations

VII-1 Develop comprehensive policies and procedures for the operation of Manlove Field and for providing Hub services.

Priority policy areas addressed should include inventory measurement practices, metering practices and their relationship to LAUF, and priority of access. Full operating policies and procedures should follow. These policies and procedures should be completed within six months of the date of this report.

VII-2 Improve and consolidate the authority and responsibility for Manlove Field.

Currently, at least five organizational groups interact with Manlove, either receiving data or information from them, providing information to them, providing direction to them. At the same time, the level of understanding of the operational parameters of Manlove appears to be low at headquarters. One organizational unit should have responsibility for oversight over all of the Manlove interfacing, to ensure that all aspects of its operations are understood and considered.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

VII-3 Prepare a comprehensive report on Manlove measurement issues, including levels of cushion and inventory gas, and how injection and withdrawal volumes are to be measured, reported, and compared.

Manlove Field needs a baseline analysis to determine the levels of inventory and cushion gas to be used going forward, with rigorous procedures as to how injections, withdrawals, cushion losses, and any other factors affecting it will be treated. In conjunction with improved and standardized operating practices, the levels of cushion gas required to maintain performance should be more predictable. Furthermore, Peoples Gas should develop an averaging method (for example, a rolling average over several years) for dealing with changes to cushion-gas requirements. Field parameters change slowly, but Peoples Gas has a history of changing cushion allocations, sometimes dramatically, from year to year. In conjunction with standard physical inventory procedures addressed in Recommendation VII-1, Peoples Gas should develop procedures for comparing metered and physical inventory volumes and how they are to be reconciled. The Utilities should complete the report within six months of the date of this report.

VII-4 Demonstrate why the Hub should not bear on-system customers' share of increased maintenance gas.

Despite its consultant studies to the contrary, Peoples Gas maintains that no additional cushion gas was required to support development of the Hub. This argument does not comport with the information available to Liberty. The Peoples Gas Manager of Gas Storage testified in the 2001 Reconciliation Proceeding that two percent of injected quantities was sufficient for maintenance prior to development of the Hub.[414] Peoples has now increased that number to three and one-half percent. Taken in conjunction with the consultant's reports which state that approximately 50 percent additional cushion gas is required to support an expansion, Liberty concludes that the increase represents belated recognition by the Company that the additional cushion gas is indeed required to maintain Field performance.

On-system customers should not be responsible for the costs of this increase. Peoples Gas should reduce those customers' requirement to provide maintenance gas to the level it was prior to development of the Hub (two percent), and increase Hub customers' maintenance-gas assessment as necessary to maintain Field performance. Alternatively, Peoples Gas should demonstrate why this adjustment should not be made. Any such proof should be required to be presented in the Company's next gas-cost reconciliation proceeding.

VII-5 Develop a structured process for analyzing and documenting major decisions.

The process must include quantitative and qualitative evaluation of alternatives, and recording of reasons for decisions. The purpose of developing and maintaining a record of such decisions is to ensure that Peoples Gas performs the analyses, that the relevant individuals and organizational units in the company are aware of it, and that it is done for the right reasons.

The Utilities should complete the implementation of this recommendation within six months of the date of this report.

VII-6 Analyze the incremental costs of the various Hub services.

Liberty has concluded that, overall, the Hub is covering its incremental costs and contributing to fixed costs. The data are not available to determine whether that conclusion applies to each individual Hub service. Peoples Gas should collect that data, perform the analysis, and

[414] See the cite to Mr. Puracchio's testimony in the Order in the 2001 Reconciliation Proceeding, at p. 81.

discontinue or modify any services that are not covering their own variable costs and contributing to fixed-cost recovery.

Peoples Gas should complete the implementation of this recommendation within six months of the date of this report.

VII-7 Determine whether and to what extent the Utilities could substitute Manlove Storage volumes for more expensive leased storages.

Peoples Gas claims that it has optimized the use of Manlove for ratepayers and that it cannot use any more of Manlove's volumes for ratepayers. That claim is unsubstantiated, and the Utilities should support it by a detailed analysis. The analysis should include a review of the cost of any facilities that might be required to enable Peoples Gas to use more of Manlove's capacity for the benefit of ratepayers. This analysis should be completed within six months of the date of this report.