REVIEW OF THE 1995 ANNUAL AUTOMATIC ADJUSTMENT REPORTS

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

BY THE
MINNESOTA DEPARTMENT OF PUBLIC SERVICE

DOCKET NO. G,E999/AA-95-844

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EXECUTIVE SUMMARY

Since 1985, Minnesota Rules parts 7825.2800-7825.2830 have required utilities implementing automatic adjustments in the recovery of fuel-cost purchases to file annual automatic adjustment reports. The reports verify whether utilities are calculating their adjustments properly and implementing them in a timely manner. In reviewing the 1994-95 filings, the Minnesota Department of Public Service (Department) incorporated information from prior years' reports as well as continuing and building on its assessment of the utilities' automatic adjustment filings throughout the reporting period.

The Department's review of the electric utilities' report includes analyses of:

1. procurement policies;
2. dispatching procedures;
3. cost-minimizing efforts;
4. adjustment computations;
5. auditor's reports;
6. fuel-cost projections; and
7. compliance with Minnesota Rules part 7825.2810, subpart 1.

Five of the six regulated electric utilities provided the information necessary to meet its filing requirements; and the Commission has previously granted Northwestern Wisconsin Electric Company (Northwestern) a variance from filing the required annual automatic adjustment report.

The Department's review of the seven regulated gas utilities' reports include analyses of:

1. 1994-95 automatic adjustment charge calculations filed pursuant to Minnesota Rules part 7825.2810;

2. filings to reconcile or "true-up" estimated volumes reported and billed to actual volumes consumed as required by Minnesota Rules part 7825.2910;

3. any supplemental annual reporting requirements ordered by the Commission in miscellaneous filings during the reporting period; and

4. reports which were suggested by the Minnesota Public Utilities Commission (Commission or PUC) in Docket No. G,E999/AA-94-762.

The instant report reviews companies' compliance with the Commission's Rules governing the filing of the annual automatic adjustments and makes a number of specific recommendations to assure compliance with Minnesota Rules parts 7825.2810 and 7825.2910 and to improve the usefulness of future annual automatic adjustment reports. These recommendations are listed in the Summary of the Department's Recommendations and Conclusion Section of this report.

Several reports are based upon the Commission's suggestions, and contain information which is not specifically required by Minnesota Rules. The Department believes that these additional reports provide useful information to the Commission for comparing Minnesota gas utilities. Therefore, the Department issued information requests and worked with all of the gas utilities to obtain the necessary data. Based on this information, the Department developed reports which provide:

- comparisons of estimated and actual weighted-average-cost-of-gas;
- gas utilities' comparative rankings in each of the following areas:
  - average annual total bill per residential customer;
  - commodity margin per unit charged to the residential customer; and
  - cost of gas storage per unit.
- gas utilities' peak-day demand and load-factor profiles; and
- comparison of transition costs resulting from implementation of FERC Order No. 636.

In addition to the above, the Department developed reports which:

- review penalty charges as part of gas utilities' portfolio decisions;
- provide information on pipeline firm transportation capacity release;
- review gas utilities reserve margins; and
- analyze lost and unaccounted for gas.

The Department notes that the 1994-95 report includes the first full year (12-month) of operation under FERC Order No. 636. When comparing the information contained in this report, it is important to remember that the previous report reflected the implementation of Order 636 which was effective November 1, 1993 and presented only eight months of operation under Order 636. This report reflects the gas purchasing practices (and the associated costs) in the "Post Order 636" market of unbundled interstate natural gas services.

The Department notes that this year's review for both electric and gas utilities once again has been slightly modified from previous reports. We have attempted to display the comparative data among both electric and gas utilities in a way that provides the Commission and others with a better view of the operations and actions of Minnesota regulated utilities. This is best seen in the review of the over-/under-recoveries for the fuel purchases made during the current true-up period and the comparisons with previous recoveries. The Department believes that this revision increases compatibility with the additional reports suggested by the Commission and those required in numerous miscellaneous filing.

The culmination of these reports took much time and effort by the Department and the utilities. The Department appreciates the companies' cooperation in developing the data for these reports.

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II. ELECTRIC UTILITY EVALUATION

A. *OVERVIEW*

This report summarizes the Department's review of the 1995 automatic adjustment charge calculations filed in compliance with Minnesota Rules part 7825.2810. Five of the six regulated electric utilities provided the information necessary to meet its filing requirements.

The Commission granted Northwestern Wisconsin Electric Company a variance from the annual reporting requirements in its Order dated October 21, 1994 (Docket No. E016/M-94-885). Despite the utility's exemption from filing an annual report, the Department prepared an analysis of the Company by independently compiling and evaluating existing data.

The Department's review focused on whether the utilities had, since their most recent general rate cases, adjusted their energy rates to accurately reflect changes in fuel costs. This review included an analysis of procurement policies, dispatching procedures, cost-minimizing efforts, adjustment computations, auditor's reports, and fuel-cost projections.

B. *FILING REQUIREMENTS*

The filing requirements for electric utilities, as stipulated by Minnesota Rules part 7825.2810, subpart 1, include the following:

- Subpart A -- The Commission-approved base cost of fuel.
- Subpart B -- Billing adjustment amounts charged to customers for each type of energy cost such as nuclear, coal, or purchased power.
- Subpart D -- The total cost of fuel delivered to customers.
- Subpart E -- The revenues collected from customers for energy delivered.
- Subpart G -- The amount of refunds credited to customers.

Most of the electric utilities computed billing adjustments as a company total and calculated total fuel costs on a system-wide basis. This approach is consistent with their monthly automatic adjustment filings. The Department continues to have no objection to this interpretation of the filing requirements since the Department concluded it was a more cost-effective approach in previous proceedings. Therefore the Department believes that the annual automatic adjustment reports from all five reporting utilities comply with the Commission's filing requirements, as described in Minnesota Rules part 7825.2810.

C. *INDIVIDUAL ELECTRIC UTILITY EVALUATIONS*

Table 1 summarizes the electric utilities' fuel-cost recovery during the 1994-1995 reporting period.

Table 1
Summary of Automatic Fuel Adjustments
July 1, 1994 through June 30, 1995

Company	Fuel Cost Recovered ($)	Fuel Cost ($)	Over/Under Recovery ($)	Over/Under Recovery (%)
Dakota Electric Assn	49,330,100	49,367,892	(37,792)	(0.08%)
Interstate	10,944,932	10,751,629	193,303	1.80%
Minnesota Power & Light	77,309,546	79,151,357	(1,841,811)	(2.33%)
Northern States Power	284,757,880	282,143,755	2,614,125	0.93
Northwestern Wisconsin	14,034	14,088	(54)	(0.38%)
Otter Tail Power	23,033,487	22,914,815	118,671	0.52%
TOTAL	445,389,979	444,343,536	1,046,442	0.24%

To review the utilities' calculations of automatic adjustment charges, the Department compared actual costs of fuel purchased during the year to the fuel costs recovered through automatic adjustments. The Department recognizes that, over time, utilities will normally experience small over- and under-recoveries. Potential causes include weather variations, calculation errors, and changes in sales. In addition, the use of a two-month moving average for calculating kWh sales and fuel costs results in some over- and under-recovery. Attachment 1 illustrates this pattern over a ten-year period.

Table 2 shows the historical over- and under-recovery for each utility, including the current reporting period.

Table 2
Percent Over-Recovery (Under-Recovery)
1987-88 through 1994-95

Electric Companies

	1987-88	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	8-Yr Ave
Dakota	0.72%	(0.74%)	(1.57%)	1.76%	(0.07%)	0.67%	(1.56%)	(0.08%)	(0.11%)
Interstate	(1.06%)	0.91%	(0.90%)	0.49%	(0.88%)	0.89%	0.18%	1.80%	0.18%
MP	(1.24%)	7.39%	(0.43%)	(3.33%)	0.55%	0.85%	5.03%	(2.33%)	0.81%
NSP	0.90%	2.09%	(0.83%)	(3.56%)	6.09%	(0.71%)	(3.52%)	0.93%	0.17%
NWE	2.13%	(2.24%)	0.46%	0.53%	(0.54%)	0.74%	0.07%	(0.38%)	0.08%
OTP	0.68%	1.21%	1.89%	0.71%	2.30%	1.45%	0.96%	0.52%	1.22%

(Supporting spreadsheets with detailed calculations are contained in Attachment 2)

The Department summarizes below the explanations for the large over- or under-recoveries experienced by the utilities.

As an electric cooperative, Dakota Electric requires special consideration because it recovers purchased capacity costs through the fuel adjustment clause. The inclusion of these capacity costs increases the Cooperative's over- or under-recovery. Purchased capacity costs are not as closely linked to variations in sales as energy costs; therefore, changes in sales can result in a significant gap between a utility's actual purchased capacity costs per kWh and the purchased capacity costs per kWh built into its base rates. Utilities that recover only energy costs through their automatic adjustments are not subject to this over- or under-recovery of capacity costs. To account for potential discrepancies between its actual costs and costs recovered through its automatic adjustment, Dakota Electric calculates a fuel cost true-up factor based on these discrepancies semi-annually.

Interstate experienced individual months of double digit undercollection as well as individual months of overcollection during the 1994-95 period, which was related to the two-month lag in the automatic adjustment calculation and its application to a different volume of sales than was used in the calculation of the adjustment.

Minnesota Power's large over-recovery in 1988-89 resulted from a lengthy period of declining fuel costs for the Company. Because of the two-month lag inherent in the automatic adjustment calculation, over-recovery occurs when fuel costs decline over a long period. The Company explained that the large over-recovery for the 1993-94 period was primarily due to the delayed recovery of the Peabody buyout amortization costs which were included during the period October 1993 through December 1993. However, due to the lag in the fuel adjustment, these costs were not recovered until January 1994 through March 1994. During the 1994-95 period, the Company experienced individual months of double digit undercollection as well as individual months of overcollection, which was related to the two-month lag in the automatic adjustment calculation and its application to a different volume of sales than which was used in the calculation of the adjustment.

NSP's large over-recovery in 1991-92 was due to the unavailability of its nuclear units in May and June 1991, forcing the Company to purchase higher-cost replacement energy. Due to the lag in using a historical, two-month moving average to compute fuel-cost adjustments, NSP included the higher fuel costs in the 1991 reporting period, and recovered them in the 1992 reporting period. The bulk of NSP's under-recovery in the current reporting period occurred in June 1994; the Prairie Island unit was unavailable, causing the Company to purchase higher-cost replacement energy. New, lower base cost rates, effective April 1994, as well as a changeover from billing-month sales to calendar-month sales (April 1994) for fuel adjustment calculations, may have also contributed to this under-recovery. During the 1994-95 period, the Company experienced individual months of double digit undercollection as well as individual months of overcollection, which was related to the two-month lag in the automatic adjustment calculation and its application to a different volume of sales than which was used in the calculation of the adjustment.

The Department examined Northwestern Wisconsin's monthly power-cost adjustment data in order to estimate its over- or under-recovery. Because the Department independently calculated this percentage, the Department's calculations may vary from the Company's calculations.

D. COMMISSION REQUESTED ANALYSIS

In its Order dated July 13, 1995 in Docket No. G,E999/AA-94-762, the Commission requested the Department provide a brief analysis of the electric utilities' procurement policies, dispatching procedures, cost-minimizing efforts, and fuel-cost projections in its 1995 annual automatic adjustment review. The data which the Commission requested that the Department provide an analysis of has been provided by the utilities in compliance with Minnesota Rules part 7825.2800 (ANNUAL REPORTS; POLICIES AND ACTIONS), and Minnesota Rules part 7825.2830 (ANNUAL FIVE-YEAR PROJECTION).

Attachment 3 is a synopsis of the electric utilities' (Interstate, Minnesota Power, Northern States Power and Otter Tail) procurement policies, dispatching procedures, cost-minimizing efforts and fuel-cost projections in adherence with the Commission's Order in the last report.

The electric utilities' (Interstate, Minnesota Power, Northern States Power and Otter Tail) fuel procurement policies and/or practices strive to purchase fuel and transportation (energy costs) at the lowest price within the constraints of environmental regulations. Dakota's sole supplier is Cooperative Power Association (CPA) which is a generation and transmission cooperative.

The electric utilities' (Interstate, Minnesota Power, Northern States Power and Otter Tail) dispatching procedures all include a systematic review of alternatives utilizing various computer programs to help in their decision making. Because CPA is Dakota's sole supplier, CPA makes all of Dakota's dispatching decisions.

The electric utilities' (Dakota, Interstate, Minnesota Power, Northern States Power and Otter Tail) all have aggressively pursued various forms of cost-minimizing activities. These efforts include load management and conservation programs, aggressive monitoring of all plant and fuel-related data, the latest computer programs, the structuring of fuel and transportation contracts to best follow the market. The result of this activity is that Minnesota ratepayers have the use of some of the lowest cost and most efficient facilities in the country.

The electric utilities' (Dakota, Interstate, Minnesota Power, Northern States Power and Otter Tail) fuel-cost projections over the next five years appear to be relatively stable. The reports as filed by each utility details their projected fuel costs for each of the next five years.

III. GAS UTILITY EVALUATION

A. *OVERVIEW*

The Department's review indicates that all seven regulated gas utilities met the annual filing requirements, including information relating to fuel procurement and the annual true-up adjustment. The Department finds that the annual filings are complete and accurate as originally filed or subsequently amended and recommends that the Commission accept the utilities' annual report filings. The Department's report includes the following:

- summaries of the gas utilities' 1994-95 automatic adjustment charge calculations filed pursuant to Minnesota Rules part 7825.2810;
- analyses of the gas utilities' true-up filings required by Minnesota Rules part 7825.2910, subpart 4[1];
- reviews of supplemental reporting requirements ordered by the Commission in miscellaneous filings;
- reports required by the Commission in its July 13, 1995 Order to the 1993-94 annual report (Docket No. G,E999/AA-94-762).

B. *FILING REQUIREMENTS*

Minnesota Rules part 7825.2810, subparts 1 and 2, contain the following filing requirements for gas utilities:

<u>Subpart 1</u>

- Paragraph A -- Commission-approved base cost of gas;
- Paragraph B -- billing amounts in Mcf, Ccf, or Btu for each type of energy cost; e.g., purchased gas, peak shaving or manufactured gas;
- Paragraph C -- billing adjustment amounts;
- Paragraph D -- total cost of gas;
- Paragraph E -- revenues collected;
- Paragraph F -- supplier refunds received; and
- Paragraph G -- refunds credited to customers.

[1] Docket numbers for 1995 Gas Utility True-Up filings: G001/AA-95-991, G002/AA-95-918, G004/AA-95-1011, G004/AA-95-1007, G004/AA-95-1009, G007/AA-95-995, G008/AA-95-928, G011/AA-95-995, G011/AA-95-996, G011/AA-95-997, G011/AA-95-998, and G012/A-95-911.

Subpart 2

- Paragraph A -- a listing of all variances in effect or requested;
- Paragraph B -- identification of all changes in demand contracted;
- Paragraph C -- the level of customer-owned gas volumes delivered through the utility's system; and
- Paragraph D -- a brief explanation of deviations between gas-cost recovery and actual cost.

In addition to reviewing the basic data, the Department investigated and developed additional data needed to provide more detailed information that the Commission requested. This information is presented to assist the Commission in its review of the different gas utilities.

C. *GAS UTILITIES SUMMARY*

The Department reviewed the utilities' filings to identify any systematic patterns of over- or under-recoveries that may be occurring over time, to identify any incorrect calculations of the annual true-up adjustment factors, and to address the companies' compliance to additional annual automatic adjustment report filing requirements as ordered by the Commission in miscellaneous filings.

As discussed further in Part E, the Department attempted to identify each Company's estimated revenue recovery by pipeline system and customer class to allow for full verification of the annual fuel costs and the related annual true-up adjustments. The Department reviewed the reasonableness of the utilities' explanations of differences between actual gas-costs and gas-cost recovery (required in Minnesota Rules part 7825.2810, subpart 2, paragraph D). Further, since Minnesota Rules part 7825.2910 require that gas utilities "true-up" all over- and under-recoveries of gas costs, the Department also investigated the accuracy of each utility's annual true-up adjustments.

Table 3 below summarizes the fuel cost recovery during the 1994-95 reporting period for gas utilities. Section E provides analyses of the individual utilities.

TABLE 3
Summary of Gas Companies Annual Fuel Cost Recovery
July 1, 1994 through June 30, 1995

	Gas Cost Recovered($)	Cost of Gas($)	Over/(Under) Recovery($)	Over/(Under) (%)
Great Plains	$10,987,130	$11,083,583	($96,453)	(0.87%)
Interstate	6,064,271	$6,247,031	($182,760)	(2.93%)
Minnegasco-Northern	$333,005,383	$335,721,705	($2,716,322)	(0.81%)
Minnegasco-Viking	$476,169	$495,799	($19,630)	(3.96%)
NMU	$19,929,962	$20,032,876	($102,914)	(0.51%)
NSP	$155,118,770	$157,017,924	($1,899,154)	(1.21%)
Peoples Natural Gas	$54,362,080	$53,700,006	$662,074	1.23%
Western Gas	$1,794,619	$1,564,435	$230,185	14.71%
MN TOTAL	$581,778,765	$585,923,554	($4,144,788)	(0.71%)

As shown above, the total company recoveries ranged from a maximum under-recovery of 3.96 percent for Minnegasco-Viking to a maximum over-recovery of 14.71 percent for Western Gas Utilities Inc. (Western). The weighted average for all Minnesota gas utilities was an under-recovery of 0.71 percent.

Table 4 below summarizes the over- and under-recoveries for each utility over the past ten years, including a ten-year average and the cumulative balance over-/under-recovery percent.

TABLE 4
Percent Over-Recovery (Under-Recovery)
1985-86 through 1994-95

Company	1985-1986	1986-1987	1987-1988	1988-1989	1989-1990	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	10-yr Ave	1994-1995 Cum.
Great Plains	(0.69)	(1.73)	(1.88)	1.73	(0.64)	(3.55)	(7.44)	(0.73)	4.95	(0.87)	(1.01)	(0.25)
Interstate	0.01	(4.64)	0.17	1.50	(1.54)	(0.35)	3.50	3.38	3.85	(2.93)	0.30	(3.24)
MNG-Northern	1.76	(1.86)	0.45	2.43	0.35	(1.14)	(2.56)	0.67	0.81	(0.81)	0.01	(0.81)
MNG-Viking	4.29	(4.82)	4.12	6.14	(3.60)	(5.15)	(1.15)	1.00	2.97	(3.96)	(0.02)	(4.01)
NMU	2.36	0.46	1.86	(0.95)	0.44	1.68	(1.91)	1.81	(1.11)	(0.51)	0.41	(0.54)
NSP	0.34	(0.95)	(0.22)	(0.45)	(0.62)	(1.04)	(0.29)	(0.21)	0.52	(1.21)	(0.41)	(0.88)
Peoples	0.18	(1.37)	1.66	(0.09)	0.35	(4.46)	(2.10)	2.32	(3.18)	1.23	(0.55)	0.73%
Western	2.79	(3.36)	4.38	2.64	(4.69)	(3.22)	(5.41)	1.43	1.57	14.71	1.08	14.64

The Department notes that, with the exception of Western, the deviations during the 1994-95 reporting period do not appear to be any more diverse than in prior years. Of the eight systems in Table 4, six have 10-year over-/under-recovery averages within one percent of actual costs, and two are only slightly above one percent. As discussed in Part E below, Western's over-recovery of 14.71 percent is primarily due to the suspension of the Company's Purchased Gas Adjustment (PGA) for July 1, 1994 through May 31, 1995.

Table 5 below shows a more detailed view of the causes for the current period's over- and under-recoveries. This table illustrates the subsystem and class-specific over- and under- recoveries by pipeline system for the 1994-95 true-up period.

TABLE 5
Percent Over-Recovery (Under-Recovery)
July 1994 through June 1995 by Class

	FIRM			INTERRUPTIBLE			OTHER[1]	TOTAL
Company	General Service[2]	C&I[3]	LVF[4]	SVI	LVI	Interruptible		
Great Plains								
Northern	2.62%	*	*	*	*	-1.00%	*	1.62%
Southern	-4.07%	*		0.19%	*0.19%	*		-2.99%
Total System	-1.05%	*	*	0.19%	0.19%	-1.00%	*	-0.87%
Interstate	-1.81%	*	*	-8.55%	-8.86%	*	*	-2.93%
Minnegasco								
MWG-Northern	-1.11%	*	-2.70%	1.88%	0.53%	*	*	-0.81%
MWG-Viking	-4.57%	*	*	-0.34%	*	*	*	-3.96%
NMU	-1.48%	-8.46%	0.90%	*	*	6.54%	*	-0.51%
NSP	-1.15%	-0.71%	-0.14%	-0.44%	-3.85%	*	*	-1.21%
Peoples								
Northern[5]	1.93%	*	*	1.93%	1.93%	*	0.41%	1.80%
Great Lakes	-15.93%	*	*	*	*	-16.76%	-1.72%	-16.12%
Viking	13.37%	*	*	*	*	7.61%		11.53%
Western	14.86%	*	*	*	*	11.01%	*	14.71%
MN Weighted Avg	-0.81%	-0.79%	-0.02%	1.07%	-1.15%	0.86%	0.40%	-0.71%
MN Non-Wtd Avg	2.66%	-9.17%	-1.94%	-5.33%	-10.06%	8.40%	-1.31%	0.71%

* The particular class is not served by this system.
1 "Other" includes Peoples' JT-Commodity, JT-Demand, and SVI/LV Commodity classes.
2 "General Service" includes the class distinctions of Residential, General Service (GS), Small Volume Firm (SVF), and Firm.
3 "C&I" includes the class distinctions of Commercial and Industrial, and NMU's Large General Service (LGS) class.
4 "LVF" includes the class distinctions of Large Volume Firm (LVF), NMU's Large Volume Service (LVS) class, and NSP's Large General Service class.
5 Peoples' Northern system has a GS/SVI/LVI class. Percentages are repeated in the SVI and LVI categories in the table for illustrative purposes. These amounts are not included in Peoples' Total System and MN averages for SVI and LVI classes.

Tables 4 and 5 show that with the exception of Western, as a whole, Minnesota utilities experienced total company over- and under-recoveries within five percent[2] of actual costs. However, some customer classes experienced a greater variation. The following two sections include the Department's analysis of the significant factors causing the over- and under-recoveries reported in the above tables as well as summaries of each utility's annual fuel reports, company-specific reporting requirements, and other items the Department wishes to note for the Commission.

D. IMPACTS ON RECOVERY

The Department recognizes that over- or under-recoveries of gas costs are normal occurrences due to difficulties in forecasting the competitive market for gas supplies, changes in weather and other factors affecting gas use. Over time, the Department expects small over- and under-recoveries for all utilities. Attachment 4 graphically illustrates this pattern over the last ten years.

There are several common reasons that over- and under-recovery of gas costs occur. Such reasons include:

- <u>Changes in demand costs</u> -- In general, demand costs are fixed costs of reserving pipeline capacity or the right to obtain firm gas supplies. However, since current rate design for firm residential, industrial, and commercial classes (excluding Large General Service classes) does not include a separate demand charge, costs for demand services are recovered through a per-Mcf commodity rate.[3] Through this per-Mcf charge, recovery of demand costs is spread over an estimate of gas volumes used in a year. Since demand costs and service levels changed during the year, over- or under-recovery results because previous sales did not reflect the new level of demand costs. The following notes general changes in demand costs during the year:

  - several changes in the level and mix of demand entitlements among customer classes (Attachment 6 of the instant report provides a glossary of Northern Natural Gas Company's Order 636 and other relevant terminology);

  - FERC-approved changes[4] in services and associated charges related to the transportation and movement of gas supplies on pipelines;

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[2] The Department specifies the five percent threshold per Minnesota Rules 7825.2920, Subp. 2, concerning adjustment errors.

[3] DPS Attachment 5 presents NNG billing classification for each utility.

[4] For example, Northern decreased its SBA charge from $0.4720/Mcf/month to $0.1130/Mcf/month on November 1, 1994, its Stranded 858 surcharge from $0.8210/Mcf/month to $0.3310/Mcf/month on January 1, 1995, and its Stranded 858 Reverse Auction surcharge from $0.2800/Mcf/month to

- new long- and short-term storage agreements entered into by various companies.

- Weather Variance -- Any time there is a change in usage, there is a potential for the over- or under-recovery of costs. Weather is typically the largest factor affecting sales and transportation volume usage. Concerning demand costs, warm weather generally causes under-recoveries and cold weather over-recoveries. Because PGA's recover gas commodity costs based on estimated prices from the week prior to the beginning of each month, a cold period during the middle of a month will generally lead to under-recoveries of gas commodity costs. Conversely, a cold period during the week prior to the beginning of the month will generally lead to utilities over-recovering commodity costs if the cold period continues only for a short period of time.

  During the 1994-95 reporting period, the weather during the heating season was an important factor in the interstate gas market. The weather during the period as a whole was warmer than normal. This resulted in lower-than-normal firm gas sales for space heating and, therefore, a general under-recovery of demand costs compared to a normal weather year. In addition, the warm weather often resulted in lower gas commodity costs; hence, most utilities over-recovered gas commodity costs.

- Test-Year Sales Volumes -- Since the monthly PGA calculation is based on a sales figure, calculated according to Minnesota Rules 7825.2700, subpart 5, a utility must use the test-year sales figure from its most recent rate case for three years after its rate case. Afterwards, the company may use a new calculation of projected sales. Since sales have generally increased over time, this recovery method typically results in an over-recovery of the demand charges.

- Gas gains or losses -- For commodity costs, a common cause of over- or under-recovery is gas gains or losses due to inaccurate estimates (i.e., customers actually using more or less gas due to weather, fuel switching, etc.). Utilities use an estimated gas sales volume to calculate the commodity rate passed to customers via the PGAs. However, due to gas gains and losses, the estimated PGA sales volume may be inaccurate.

$0.005/Mcf/month in April 1995. Depending on the timing of the change and the sales during the remaining reconciliation period, the utility could either over- or under-recovery costs.

- Prorating of customer bills -- When a utility reads a customer's meter in the middle of the month, the registered usage represents consumption from two different PGA (calendar month) periods. Thus, the utility must bill the customer based on an estimate of the consumption that took place during each PGA period. Because this prorated bill will never exactly match the true consumption that took place each month, over- or under-recoveries result.

- The three-cent rule -- Minnesota Rules part 7825.2700, subpart 3, specifies that companies need not file monthly PGAs if the change during the month is less than $0.03 per 1,000,000 Btus (1,000,000 Btus approximately equals 1 Mcf). This allowance, if exercised by a utility, could cause an over- or under-recovery of gas costs.

The Department notes that to some extent, all of the above factors affect the recovery of gas costs for all of Minnesota's regulated gas utilities. The following section concerning each individual gas utility highlights the items from this list and any particular causes not in the list which cause notable over- and under-recoveries.

E. *INDIVIDUAL GAS UTILITY ANNUAL AUTOMATIC ADJUSTMENT REPORT AND TRUE-UP EVALUATIONS*

1. *Great Plains Natural Gas Company*

a. Recovery of Gas Costs and True-up Calculations

For the reporting period, the Company under-recovered its gas costs by 0.87 percent, for a cumulative under-recovery of 0.25 percent.[5]

[5] This percent represents the accumulated under-recovery of $27,298 and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based. For a detailed analysis of the true-up calculations, please see Docket Nos. G004/AA-95-1009 and G004/AA-95-1011 (customers served by the Viking pipeline) and G004/AA-95-1007 (customers served by the Northern pipeline) on file at the Department of Public Service.

The Department's analysis indicates that, by pipeline system and class, Great Plains' over- and under-recoveries in 1994-95 were as follows:

Percent Over-recovery (Under-recovery) by System[6]

	Firm(%)	SVI(%)	LVI(%)	Interruptible(%)	Total(%)
Northern System[7]	2.62	*	*	-1.00	1.62
Southern System	-4.07	0.19	0.19	*	-2.99
TOTAL SYSTEM	-1.05	0.19	*0.19	-1.00	-0.87

* Great Plains does not serve customers of this class in this zone.

The Department's analysis shows that Great Plains' Northern System had an overall over-recovery of 1.62 percent. This was primarily due to:

1. Weather that was 2.4 percent warmer-than-normal and actual firm sales of 2.49 percent over what was projected via the PGA's Three Year Normalized Average forecasting method.

2. Great Plains over-recovered demand components by $111,762 or approximately 5.94 percent, due to changes in demand entitlement levels and the timing of changes in transportation surcharges. (See DPS Attachment 7 for a summary of all the factors identified by Great Plains.)

3. Great Plains under-recovered commodity components of the PGA by $29,138 or 0.91 percent. This under-recovery was due primarily to the dekatherm adjustment component of the commodity costs. The dekatherm adjustment results from variations in Btu factors that ranged from 1.011 to 1.016 for the year. Since Great Plains purchases gas supplies from Viking on a dekatherm basis and sell on an MCF basis and because the reconciliation for this difference is not performed until the end of the true-up period there is usually an under-recovery in total commodity components. The remaining difference in recovery of commodity component costs is due to the reconciliation of the estimated

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6 Supporting spreadsheets with detailed calculations are contained in Attachment 7.

7 Northern System refers to the six communities served by the Viking Gas Transmission Company's (Viking) pipeline which were consolidated for Great Plains' true-up. Great Plains has always "trued-up" its Northern District communities of Fergus Falls, Pelican Rapids, Breckenridge, Crookston and Vergus (all in Minnesota) and Wahpeton (in North Dakota), in a combined true-up because these communities jointly use the Company's peak shaving and transmission facilities. This practice was started when Great Plains received approval from the Minnesota Public Utilities Commission and North Dakota Public Service Commission to "true-up" its supplemental fuel and peak shaving costs in the PGAs. In the annual report to the Commission, Great Plains separately reports the over-/under-recovered amounts for Crookston, Wahpeton and the remaining Northern Minnesota towns. Minnesota customers do not subsidize Wahpeton's customers because Great Plains uses the true-up mechanism in North Dakota based on Wahpeton's peak day requirement.

average costs versus the actual costs. Great Plains portfolio includes "spot" gas supplies that can be subject to daily price fluctuations. These daily prices cannot be forecasted precisely, consequently some differences remain between estimated and actual costs.

The Department's analysis shows that Great Plains' Southern System had an overall under-recovery of 2.99 percent. This was primarily due to:

1. The fact that actual firm sales were 7.62 percent less than what was projected via the PGA's Three Year Normalized Average forecasting method. This decrease in firm sales was due to 9.6 percent warmer than normal winter heating season which consists of the months of November through March.

2. The warmer-than-normal temperatures were the primary factor which lead to a demand under-recovery of $183,710 or 7.81 percent. The Company also identifies changes in entitlement levels as well as changes in transportation-related surcharges that resulted in the demand under-recovery. (See DPS Attachment 7 for a summary of all the factors identified by Great Plains.)

3. The Company over-recovered commodity components by $4,633 or 0.13 percent due to the reconciliation of the estimated average costs versus the actual costs. Great Plains portfolio includes "spot" gas supplies that can be subject to daily price fluctuations. These daily prices can not be forecasted precisely, consequently some differences remain between estimated and actual costs. These differences accounted for the small over-recovery.

The Department believes that the Company's current annual automatic adjustment report is reasonable. As in the past, Great Plains reviewed its PGA forecasting and its over- and under-recoveries to ensure that the difference between gas costs and recoveries was minimized except for factors beyond the Company's control.

b. Supplemental Reporting Requirements

In Docket Nos. G004/M-94-21 and G004/M-94-22, the Commission ordered Great Plains to submit two additional reports in conjunction with the annual automatic adjustment report: (1) a report of all capacity-release transactions; and (2) a report of all penalties imposed on the Company by its pipelines suppliers and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Section F of the instant report.

2. *Interstate Power Company-Gas*

a. Recovery of Gas Costs and True-up Calculations

Interstate Power Company (Interstate or the Company) submitted its automatic adjustment filing on August 30, 1995. On September 5, 1995, the Company submitted an addendum to its annual true-up filing. Subsequent to Department review and questions about inconsistencies, on January 10, 1996, Interstate submitted another revision to its annual true-up filing.[8] The Department believes that Interstate's January 10, 1996 filing is accurate regarding calculations of recoveries and costs by class and component. Interstate concurs with the Department's corrected true-up calculation (see Attachment 8) and has stated that it will apply the corrected true up beginning with its March 1996 PGA.

For the reporting period, the Company under-recovered its gas costs by 2.93 percent, for a cumulative under-recovery of 3.24 percent.[9]

By class, Interstate's recovery in 1994-95 is summarized as follows:

Percent Over-Recovery (Under-Recovery) by Class[10]

	Total
Firm	-1.81
Small Interruptible	-8.55
Large Interruptible	-8.86
Total System	-2.93

Interstate's total present year under-recovery does not exceed a five percent deviation. However, the Department notes that the Company did exceed this level in the Small and Large Interruptible Customer Classes. The Department's analysis of Interstate's fuel cost shows that the most significant contributing factor to the under-collection was the weather. The weather was much warmer during the reconciliation year than expected during a normal heating season. That is, Interstate reports there were 582 less heating degree days than normal during the November, 1994, through March, 1995, period. In addition, the two marginal heating load months of September, 1994, and October, 1994, were 24 and 17 percent, respectively, below normal of heating degree days.

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8 Interstate's revision to its annual true-up filing is available for review at the Department (Docket No. G001/AA-95-991).

9 This percent represents the accumulated under-recovery of $202,525, and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based. For a detailed analysis of the true-up calculations, please see Docket No. G001/AA-95-991 on file at the Department of Public Service

10 Supporting spreadsheet with detailed calculations is contained in Attachment 8.

b. Supplemental Reporting Requirements

In Docket No. G001/M-93-1219, the Commission ordered Interstate to submit in conjunction with the annual automatic adjustment report a report of all capacity-release transactions and to return all capacity release revenues to ratepayers. In Docket No. G001/M-93-1171 the Commission ordered Interstate to submit a report of all penalties imposed on the Company by its pipelines suppliers and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report.

3. *Minnegasco*

a. Recovery of Gas Costs and True-up Calculations

In the prior reporting period, Minnegasco filed separate true ups for its traditional Northern service area, its former Midwest Gas Northern service area, and its Viking service area. However, in Minnegasco's last rate case (Docket No. G008/GR-93-1090), the Commission allowed Minnegasco to consolidate rates[11] for its customers in Minnegasco's Northern service areas (page 45 of the Commission's *Finding of Fact, Conclusions of Law and Order*, dated October 24, 1994). Hence, during the current reporting period, Minnegasco filed true ups for its combined Northern service area and its Viking service area.

For the current reporting period, Minnegasco's Northern service area under-collected its gas costs by 0.81 percent, with a cumulative under-recovery of 0.81 percent.[12] The Viking area experienced an under-recovery of 3.96 percent, with a cumulative 4.01 percent under-recovery.[13]

By class, Minnegasco's recovery in 1994-95 is summarized as follows:

Percent Over-Recovery (Under-Recovery) by Class[14]

System	SVF	LGS	SVDF	LVDF	Total
Northern	-1.11	-2.70	1.88	0.53	-0.81
Viking	-4.57	*	-.34	*	-3.96

* Minnegasco does not serve customers of this class on this system.

11 Gas Costs were consolidated on November 1, 1994 and non-gas costs were consolidated on June 1, 1995.

12 This percent represents the accumulated under-recovery of $2,727,777 and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based. For a detailed analysis of the true-up calculation, please see Docket No. G008/AA-95-928 on file at the Department.

13 This percent represents the accumulated under-recovery of $19,874 and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based. For a detailed analysis of the true-up calculation, please see Docket No. G008/AA-95-928 on file at the Department.

14 Supporting spreadsheet with detailed calculations is contained in Attachment 9.

The Department's analysis shows that the deviation between both Minnegasco's and Midwest's gas recoveries and actual costs was caused by the following:

1. The largest factor in the under-recovery of demand gas costs was due to the weather, which the Company reports as being approximately 8 percent warmer than normal. Also, numerous changes in demand costs occurred during the reporting period. Thus, timing differences occurred between actual costs and the annualized demand recovery method.

2. The Commission's Order in Docket No. G008/M-94-853 reallocated costs among Minnegasco's Northern and Viking systems. As a result, Minnegasco had not included the full level of demand costs in its Viking area billing rates during the period July 1994 through October 1994.

Because of the first factor, the Minnegasco Northern system had under-recoveries of demand costs by $7,024,484 (4.94 percent). The Viking system under-recovered demand costs by $20,268 (10.38 percent), mostly because of the reallocation of costs described above.

Minnegasco over-recovered commodity costs by $3,979,262 (2.06 percent) on the Minnegasco Northern system and over-recovered commodity costs by $638 (0.21 percent) on the Viking system. Commodity cost recovery rates are based on estimated monthly rates and volumes prior to the start of the month. This caused most of the differences in over- and under-recoveries.

Minnegasco is authorized by the Commission to bill Northern area firm customers $0.00051/therm per month for recovery of propane costs, although some propane was used to serve dual-fuel customers as well. The true-up calculations compensate for this inequality by applying the true-up factor to all customers on the Northern system. Since, very little propane was used for peak shaving during the 1994-95 reporting period due to the warmer weather, propane costs were over-recovered by $328,900 (367.63 percent) on the Minnegasco Northern system.

b. Supplemental Reporting Requirements

Paragraph 9 of the Commission's Order in Docket No. G008/PA-93-92 requires Minnegasco to submit annual reports for three years or until it files a rate case (whichever is longer) as supplements to its annual automatic adjustment report concerning the Company's gas purchasing strategies and portfolios including: third-party-gas purchases, realized annual saving resulting from the Minnegasco-Midwest Gas exchange, projected annual savings, analysis of additional use of Minnesota Intrastate Pipeline Company, and a description of expansion projects enabled by the exchange by customer class and pipeline.

To comply with the Commission's Order, Minnegasco provided the Minnegasco/Midwest acquisition adjustment information included in the Company's current rate case (Docket No. G008/GR-95-700). This issue is being explored in that rate case.

In Docket No. G008/M-92-777, the Commission ordered Minnegasco to provide a cost/benefit analysis of the Natural Gas Pipeline of America (NGPL) Storage Program agreement's performance and a summary of all capacity improvements associated with the Northern agreement each year in its annual fuel report. The Department reviewed the Company's cost/benefit analysis and believes that it should be accepted as complying with the Commission's Order.

In its October 24, 1994 *Findings of Fact, Conclusions of Law,* and Order regarding Docket No. G008/GR-93-1090, the Commission required Minnegasco to report, in its next annual fuel report, on the Company's efforts to lower its demand and commodity costs of gas. To comply with the Commission's requirement, Minnegasco included its Proprietary Exhibit G with its 1995 annual fuel report.

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The Department notes that demand costs for former Midwest customers have decreased since the consolidation of the Midwest-Northern and Minnegasco-Northern systems (see page 5 of Attachment 9), though it would be difficult to attribute the decrease to any specific actions or to determine what the costs would have been had the consolidation not been approved. Further, the Department notes that Minnegasco has filed a plan for Performance Based Rates (Docket No. G008/M-95-465) which is currently pending before the Commission. If approved, the Performance Based Rates plan will provide direct incentives for the Company to lower its gas costs. However, the Department believes that Minnegasco has complied with the Commission's Order and recommends that the Commission accept the Company's filing.

In Docket Nos. G008/M-93-1233, G008/M-93-1234, and G008/M-94-853 the Commission ordered Minnegasco to submit two additional reports in conjunction with its annual automatic adjustment report: (1) a report of all capacity-release transactions; and (2) a report of all penalties imposed on the Company by its pipelines supplies and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report.

4. *Northern Minnesota Utilities*

a. Recovery of Gas Costs and True-up Calculations

For the reporting period, the Company under-recovered its gas costs by 0.51 percent, for a cumulative under-recovery of 0.54 percent.[15]

By class, NMU's recovery in 1994-95 is summarized as follows:

Percent Over-Recovery (Under-Recovery) by Class[16]

	Total
General Service (GS)	-1.48
Large General Service (LGS)	-8.46
Large Volume Service (LVS)	0.90
Interruptible	6.54
TOTAL SYSTEM	-0.51

The Department's analysis of NMU's annual fuel costs by component shows that the deviation between NMU's 1994-95 gas cost recoveries and actual gas costs was caused by the following factors:

1. Demand Costs -- NMU under-recovered demand costs by $936,623 or 9.80 percent due to warmer than normal weather. NMU reported 8 percent warmer-than-normal weather.

2. Commodity Costs -- NMU over-collected commodity costs by $833,710 or 7.96 percent due to the following:

- Differences between projected and actual sales;
- Fluctuations in supplier rates; and
- A difference between the actual and projected supplier mix.

b. Supplemental Reporting Requirements

In Docket No. G007/M-94-20, the Commission required NMU to include a cost/benefit analysis of its Mobil contract with its annual fuel report. NMU estimates that the annual net benefit to NMU of the Mobil contract is *****PROPRIETARY*****. This amount is based on the Company's estimate that current charges annually under the model contract are *****PROPRIETARY*****, whereas its prior contract with Progas would annually cost *****PROPRIETARY*****.[17]

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[15] This percent represents the accumulated under-recovery of $108,208 and is the actual amount on which the 1994-95 true-up adjustments are based. For a detailed analysis of the true-up calculations, please see Docket No. G007/AA-95-995 on file at the DPS.

[16] Supporting spreadsheet with detailed calculations is contained in Attachment 10.

[17] The Department notes that People's has taken advantage of NMU's supply contract with Mobil to firm up its own supplies of gas, and is paying NMU for the supplies used.

Docket No. G007/M-94-20 also required NMU to submit two additional reports in conjunction with its annual automatic adjustment report: (1) a report of all capacity-release transactions; and (2) a report of all penalties imposed on the Company by its pipelines supplies and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report.

In addition, the Department notes that in Docket No. G011,007/AI-93-923, the Commission required the Company to "quantify all benefits and costs of using UtiliCorp to provide the [gas procuring] services rather than using other reasonable methods of procuring gas" as part of NMU's and Peoples' annual gas reports. As with the case of Peoples (see discussion in Section F), NMU provided a qualitative discussion, but not a quantitative analysis. This issue is discussed in more detail in Part F of the instant report.

In Docket No. G007/M-94-974, NMU requested a variance from Minnesota Rules part 7825.2700, subp. 7 to permit a change in the calculation of its true-up adjustment, stating that there had been a shortfall in the recovery of gas costs related to the loss of Large Volume Service (LVS) customers. After further investigation, the Company said that it had found that the shortfall was not due to the loss of LVS customers and it requested to withdraw the petition and include the necessary corrections in its 1994-95 true up. The primary reason for the shortfall, according to NMU, is that NMU's accounting is based on an accrual basis, and NMU incorrectly forecasted March sales revenues to be approximately 600,000 MMBtus higher than the actual sales. As NMU's explanation shows, the overestimate occurred in the forecast of General Service (GS), not LVS customers. Therefore, the collection of the shortfall through the true up should come from the GS class.

In its "Order Allowing Withdrawal of Petition and Requiring Filings" in Docket No. G007/M-94-974, dated November 22, 1995, the Commission permitted NMU to withdraw the petition and required the Company to provide information regarding the filing in its September 1995 true-up filing. However, that filing had already been made on September 1, 1995. Although NMU has subsequently provided some of the required information to the Department (on February 7, 1996), it did not provide all of the required information. The Department has requested further information which the Department will analyze in conjunction with the Company and Commission Staff and will report its findings to the Commission.

5. *Northern States Power-Gas*

a. Recovery of Gas Costs and True-up Calculations

Northern States Power Company's (NSP or the Company) September 1, 1995, true-up filing as subsequently revised on September 15 and November 2, 1995, indicates that NSP under-recovered total gas costs by $1,899,154, or 1.21 percent, for the reporting period, with a cumulative under-recovery of 0.88 percent.[18]

By class, NSP's recovery in 1994-95 is summarized as follows:

Percent Over-recovery (Under-recovery) by Class[19]

	Total
Residential	-1.15
Commercial/Industrial	-0.71
Large General Service	-0.14
Small Interruptible	-0.44
Large Interruptible	-3.85
TOTAL SYSTEM	-1.21

The Department's analysis of NSP's true-up calculation shows that the deviation between NSP's gas cost recoveries and actual gas costs was primarily caused by the following factors:

1. Demand Costs -- NSP under-recovered demand costs by $1,237,922 or 2.06 percent. The under-collection is primarily attributable to:

   - Warmer-than-normal weather which resulted in a lower level of demand during the 1994-95 reporting period than the annualized level of demand used in the calculation of the PGA.

   - Annualized demand costs used in the calculation of the PGA were slightly lower than actual demand costs. This was primarily due to the inclusion of a full year of Northern's Firm Deferred Delivery (FDD) capacity charge in demand costs in the true up, whereas this capacity charge was not included in annualized demand costs in the PGA calculations until November, 1994.[20]

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18 This percent represents the accumulated under-recovery of $1,389,274 and is the amount upon which the 1995-96 true-up adjustments are based. For a detailed analysis of the true-up calculations, please see Docket No. G002/AA-95-918 on file at the DPS.

19 Supporting spreadsheet with detailed calculations is contained in Attachment 11.

20 The Commission's Order dated November 7, 1994, Docket No. G002/M-93-1149 requires NSP to reclassify Northern's FDD capacity charge as demand beginning with the 1994/95 gas year. NSP has complied by classifying Northern's FDD capacity charge as demand in the 1994/95 true-up.

2. Commodity Costs (including peak shaving costs[21]) -- NSP under-recovered commodity costs by $661,232, or 0.68 percent. The under-recovery is due to deviations between monthly forecasts and actual results for sales and commodity prices. Although NSP underestimated the level and percentage of its sales in Minnesota, it also, on average, underestimated the cost per Mcf thus leading to the overall under-recovery.

At the Department's request, NSP provided restated true ups for the past two years (1992-93 and 1993-94). These restatements reflect (1) the $1,051,827 of 1992-93 generation expense (which was at issue last year) in 1992-93, and (2) the correction of errors and (3) ****PROPRIETARY***

in 1993-94. The Department's spreadsheet included herein as Attachment 11 reflects these revisions. The true up balance to be carried forward to the current 1994-95 true up has likewise been restated.

In conclusion, the Department believes that the true-up factors as revised by NSP on November 2, 1995 (and shown in DPS Attachment 11) are appropriate and no further adjustment is necessary.

b. Supplemental Reporting Requirements

1. In Docket No. G002/GR-92-1186 the Commission required NSP to credit Standby Service revenues until the next rate case. In Schedule 10 of its Attachment F, NSP shows that demand expenses for the 1994-95 reporting period have been reduced by the amount of standby service demand revenues.

2. In Docket No. G002/AI-94-443 the Commission required NSP to file information on purchases from its affiliate, Cenergy, in the Company's monthly PGAs. In reviewing NSP's compliance in this issue, the Department found that, in practice, while NSP generally did not include purchases from Cenergy in its monthly planning, NSP often did purchase gas from Cenergy on a day-to-day basis. Based on its investigation, the Department recommended that the Commission make certain changes in its Order in the above docket. These recommendations are pending with the Commission. Specifically, the Department recommends that the Commission:

   a. revise its Order to allow NSP to use bids from at least 3 non-affiliated suppliers instead of maintaining data on Cenergy's cost of providing the gas;

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[21] Peak shaving costs became part of the total Commodity Costs as a result of Docket No. G002/GR-92-1186, effective March 2, 1994.

b. require NSP to report, in its true up, price and volume information on all intraday purchases from Cenergy. (NSP has provided this information in its Schedule 1 of Attachment F); and

c. require NSP to continue to release capacity to Cenergy through Viking at the maximum rate, not at a "market" rate, until the Commission decides otherwise on this pricing matter. Further, NSP should propose a method to ensure that such capacity releases are arms-length transactions. (NSP indicates in its Attachment F that it made short-term releases of Viking capacity to Cenergy during the reporting period at maximum rates. These transactions are summarized in Schedule 3 of NSP's Attachment F. The revenues from these capacity release sales were credited to retail ratepayers' cost of gas in the true up, as shown in Schedule 10 of NSP's Attachment F).

3. In Docket No. G002/AI-94-838 the Commission required NSP to "include in future Annual Automatic Adjustment of Charges reports monthly summaries of transactions between itself and NSPW and between itself and Cenergy." NSP has included a monthly summary of transactions between itself and NSPW and between itself and Cenergy as Schedules 5 and 1 respectively, of the Company's Attachment F.

4. In Docket No. G002/M-94-103 the Commission required NSP to amend its 1994 true-up filing so that all of the revenue from off-system sales is returned during the 1994 true-up period using estimated remaining sales volume in the denominator of the calculation of the amended 1994 true-up adjustment. The Department notes that NSP has complied with the Commission's order. *****PROPRIETARY*****

Thus, the off-system sales' revenue not returned in the 1994 true up are included in the 1994-95 true up.

5. In Docket No. G002/M-94-938 the Commission required NSP to:

a. Include a report regarding an expanded project. NSP has included the required report regarding an expanded *****PROPRIETARY***** project as Schedule 6 of its Attachment F.

b. Increase the demand volumes used to calculate the PGA demand charge by adding the forecasted Lakes Area sales volumes approved in Docket No. G002/M-94-156. Beginning with its September 1995 PGA, NSP has added the Lakes Area sales volumes (982,840 Mcf) to the demand volumes used to calculate the PGA demand charge. The Lakes Area sales volumes are also included in the current true up.

6. In Docket No. G002/AI-94-729 the Commission required NSP to report the volume of gas, gas costs, and gas revenue for service under the approved Agreement in the 1994-95 and 1995-96 true-up reports, including a report of the value of the pipeline capacity used to serve NSP Generation. NSP indicates on page 7 of its Attachment F that no pipeline capacity was used to serve the Angus Anson Generating Plant. The Company has also included Schedule 9 of its Attachment F to show the volume of gas, gas costs, and gas revenue for service under the Agreement. As discussed in greater detail in the following section concerning Docket No. G,E999/AA-94-762 reporting requirements, NSP ***PROPRIETARY***

7. In Docket No. G,E999/AA-94-762. The Commission required NSP to:

   a. Change from its intra-company accounting system to the invoicing system for its transactions with NSP Generation;

   b. Direct its external auditors to reconcile the true-up reports submitted to the Commission to the original invoices NSP Gas receives from Northern Natural and other suppliers, rather than simply using summary reports of the Company's books and records;

   c. Include in its September 1, 1995 PGA filing:

      1. a report of its investigation of whether NSP Gas was under- or overcharging NSP Generation and any provision made for refunding to NSP Gas' sales customers if a refund is necessary;

      2. a report of the Company's accounting for gas sold to NSP Generation (including gas and non-gas costs);

      3. a comparison of the Company's present intra-company accounting system with the Company's new invoicing system for transactions with NSP Generation.

NSP addresses its compliance with the above Commission Order beginning at page 5 of Attachment F to its September 1, 1995, "Annual Report -- Gas Utility Automatic Adjustment of Charges," filing. The Company indicates that its external auditors reconciled the cost information contained in its reports to supplier invoices and, in Schedule 8 of its Attachment F that it has changed to an invoicing system for its transactions with NSP Generation. Additionally, NSP has provided (1) Schedule 7 of its Attachment F to show the results of its investigation concerning under- or overcharging NSP Generation, and (2) Schedule 8 of its Attachment F to show the Company's method of accounting for gas sold to NSP Generation.

The Department believes that an important purpose of the additional reporting requirements of Docket Nos. G,E999/AA-94-762 and G002/AI-94-729 is to ensure that, regardless of the prices NSP has charged its generating plants for system supply gas, no portion of the actual cost of system gas used by the generating plants is included in the cost of gas allocated to NSP's other Minnesota gas ratepayers. In other words, when calculating the true up NSP must assign at least a pro-rata share of total system gas costs to these plants in much the same manner as it assigns a pro-rata share to North Dakota. Based on discussions with the Company and the receipt of additional information, it appears (as discussed further in the following paragraph) that NSP has assigned an appropriate amount of gas costs to the generation plants in total. Additionally, the Department and NSP have been, and plan to continue, discussing ideas on how future true ups might more clearly present the comparison of gas costs assigned to generation with the actual cost of gas used by the generation plants.

The Department notes that in the Company's Schedule 7 of Attachment F, NSP has used an annualized weighted average cost of gas rate to determine the interruptible generation sales share of actual gas costs. Additionally, the Company's November 2, 1995 revised Schedule 7 actually indicates that these generation plants *****PROPRIETARY*****

Thus, NSP's other Minnesota gas ratepayers have not been harmed and are not subsidizing the gas costs of these generation plants.

8. In Docket No. G002/M-93-1149 the Commission ordered NSP to submit two additional reports in conjunction with the annual automatic adjustment report: (1) a report of all capacity-release transactions; and (2) a report of all penalties imposed on the Company by its pipeline suppliers and all penalties imposed by the Company on its customers. The Department reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report. This Docket also required NSP to reclassify Northern's FDD capacity charge as demand. As noted previously (footnote 20), NSP has reclassified Northern's FDD capacity charge as demand in the 1994-95 true up.

c. Other

In its annual report, NSP included a request for a variance from Minnesota Rules part 7825.2700, subp. 8, which addresses returning supplier refunds to customers. Since Minnesota Rules part 7825.2700 is not one of the "Annual Automatic Adjustment of Charges" rules (7825.2800-7825.2840), NSP has agreed to refile this request as a separate docket. Therefore, the Department will address this variance request when the Company refiles it. Thus, no comment or action on this request is necessary in the current docket.

6. *Peoples Natural Gas*

a. Recovery of Gas Costs and True-up Calculations

Peoples Natural Gas (Peoples or the Company) submits three separate PGAs on a monthly basis. The three PGAs correspond to the three pipelines that serve Peoples' customers: NNG, Great Lakes, and Viking.

For the 1994-95 reporting period, the Department's investigation identifies that the Company over-recovered gas costs by 1.23 percent with a cumulative over recovery of .73 percent.[22] The Department also analyzed Peoples' reported annual fuel cost by pipeline and class. The Department's analysis indicates that, by zone and by class, Peoples' over- and under-recovery in 1994-95 was as follows:

Percent Over-recovery (Under-recovery) by System[23]

	General Service	SVI	LVI	Joint Commodity	Joint Demand	SLV	Total
Northern System	1.93	1.93	1.93	-12.63	4.29	0.00	1.80
Great Lakes System	-15.93	-16.76	-16.76	*	-1.72	*	-16.12
Viking System	13.37	7.61	7.61	*	*	*	11.53

* Peoples does not serve customers of this class in this zone.

Pursuant to Minnesota Rules part 7825.2810, subpart 2, paragraph D which requires a brief explanation of the deviation between gas cost recovery and actual gas costs, Peoples provides the following explanation for the over-/under-recoveries during the 1994-95 reporting period:

1. The total over-recovery of 1.80 percent ($894,477) on its Northern System reflects an under-recovery of pipeline related demand costs of $995,177 (6.92 percent), an over-recovery of commodity costs which includes gas supplies and daily scheduling charges of $1,346,105 (4.04 percent) and "capacity-release" credits of $543,549. Peoples accumulated capacity-release credits through the year and included the credits in the Company's 1994-95 over-/under-recovery calculations.

[22] This percent represents the accumulated over-recovery of $390,567 and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based.

[23] Supporting spreadsheet with detailed calculations is contained in Attachment 12.

Additionally, the Department notes that, as discussed in Docket Nos. G011/M-93-1092 and G011/M-94-960, Peoples recovered demand costs from firm and interruptible customers. This change increased rates for interruptible customers by 20 to 30 percent. As a consequence, most interruptible customers switched from sales to transportation service, leaving recovery of demand costs stranded. In Docket No. G011/M-94-960, the Commission ordered the Company to recover demand costs only from firm customers effective September 1, 1995.[24] The Department notes that because Peoples is the only company to have charged demand costs to interruptible customers during the 1994-95 true-up period, the rate comparison between Peoples' and other gas utilities (see Part F, "Comparison of Residential Rates") is not on an equal basis.

2. The total under-recovery of 16.12 percent ($406,821) on its Great Lakes System is due primarily to three factors: an error in rate input for producer demand in December through March; overstated demand volumes from September through December ; and a warmer-than-normal weather. The total under-recovery reflects an under-recovery of pipeline related demand costs of $4,653 (3.34 percent) and an under-recovery of commodity costs of $33,175 (1.65 percent).

3. The total over-recovery of 11.53 percent ($174,421) on the Viking System is due to the differences between the actual costs and the estimated costs included in the PGAs. Specifically, the cost included in the PGAs associated with peaking supplies was not necessary since the weather during the reporting period was warmer than normal. The total over-recovery reflects an over-recovery of pipeline related demand costs of $25,652 (30.14 percent) and an over-recovery of commodity costs of $148,769 (10.42 percent).

In addition to these effects, the Department notes that in its PGAs during the 1994-95 period Peoples made a number of errors that affected recovery of gas costs. The following briefly describes these errors:

> Peoples had errors in its PGAs in virtually every month for at least one of the three pipeline systems. The Department reported to the Commission all errors which resulted in overcharges greater than 5 percent of the corrected charge. Positive figures in Attachment 12 indicate overcharges while negative figures indicate undercharges. In addition, Peoples' auditor found discrepancies between the pipeline rates charged to Peoples and the rates Peoples used in its PGAs.

[24] The Department notes that Peoples made this change in rates, in Docket No. G011/AA-95-1374.

Most errors resulted in overcharges for customers on the NNG and Viking systems. Customers on the Great Lakes system were undercharged for the period of September 1994 through March 1995. The over-recovery of costs correspond to Peoples' erroneously high charges on the NNG and Viking systems. Likewise, the under-recovery of costs correspond to erroneously low charges on the Great Lakes system.

On the NNG system, the errors occurred for a variety of reasons, such as double-collecting demand costs from joint-rate customers, using incorrect pipeline rates, applying pipeline rates to incorrect volumes, double-collecting for TCR (transition cost recovery) costs, continuing to collect for pipeline charges that were discontinued, and increasing joint demand rates without Commission approval of the change in rate design.

On the Great Lakes system, the errors were due to implementing an incorrect true-up amount and to using inconsistent sales volumes in calculating the commodity portion of rates.

On the Viking system, the errors were due to using inconsistent sales volumes in calculating the commodity portion of rates, incorrectly implementing the correction to the true up, and double-recovering pipeline FT-A costs.

The Department estimates that, while on a stand-alone basis few errors were greater than 5 percent of the corrected charge, the errors in total accounted for roughly 20 percent of the total over- or under-collection from general-service customers on all three pipeline systems. This 20 percent figure generally does not include interest on the over-recoveries.

Despite inaccuracies during the reporting period, the Department is pleased to report that, beginning with the September 1995 PGAs, Peoples significantly improved the accuracy of its filings. While some of the PGAs were filed quite late, the more recent filings have been more timely. The Department will continue to monitor the accuracy and timeliness of Peoples' PGAs and rates.

b. <u>Supplemental Reporting Requirements</u>

In Docket No. G,E999/AA-94-762, the Commission ordered the Department to provide an "analysis of Peoples' and NMU's cost/benefit quantification of the choice of UtiliCorp as a gas supplier." Both NMU and Peoples provided a qualitative discussion but not a quantitative analysis. The Department discusses this requirement in Part F of this document.

In Docket No. G011/M-93-1248, the Commission ordered Peoples to submit a report of all capacity-release transactions in conjunction with the annual automatic adjustment report. In Docket No. G011/M-93-1093, the Commission ordered Peoples to submit a report of all penalties imposed on the Company by its pipeline suppliers and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission's Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report.

Also, in Docket No. G011/M-94-1082, the Commission ordered Peoples to provide system-wide peak-period information in its next annual fuel report. The Department's review of the information submitted by the Company indicates that on its system-wide peak-day of January 4, 1995, Peoples used 13,099 Mcf of Northern's interruptible service to meet the firm requirements. The Department recognizes Peoples has successfully used best efforts (interruptible) service to meet firm requirements in the past. However, the Department has concerns about Peoples use of best efforts service during peak times. Since the Company continues to operate with a system-wide negative reserve margin, the Department recommends that the Commission continue to require Peoples to report the following coincidental and non-coincidental peak-period information individually for all of the jurisdictions in which Peoples operates that are directly connected to the Northern system at the time of the Company's next annual fuel report:

- peak-period date(s);
- peak-period duration;
- peak-period sendout day; and
- the amount of interruptible supplies used to meet firm, peak-period requirements.

c. Other

The Department filed comments in Docket No. G011/M-95-518, which pertains to the change Peoples implemented in its NNG Joint Demand rates without Commission approval. This matter is pending before the Commission.

The Department filed comments in Docket Nos. G011/AA-95-436, 562, 670, pertaining to an error Peoples made regarding double-recovery of FT-A costs on the Viking system. While this matter is pending, Peoples has corrected the error and included a refund with interest in this true up.

7. *Western Gas Utilities*

a. Recovery of Gas Costs and True-Up Calculations

Western Gas Utilities, Inc. (Western or the Company) submitted its automatic adjustment filing and true-up report on September 1, 1995. Subsequently, the Company filed on September 20, 1995 and on January 11, 1996 two revisions to its true-up report, both of which impact the total costs shown for the reporting period in the automatic adjustment report.[25]

Further, during the Department's review of Western's annual report, the Company notified the Department of an error in the Company's filed commodity costs. The error was due to the inadvertent omission of a billing adjustment by Northern, and results in a decrease of $2,597 in the total costs incurred during the reporting period.[26]

Based on the Department's calculations, which include corrections to the Company's initial filing to reflect the points discussed above, Western over-recovered its gas costs by 14.71 percent for the reporting period, with a cumulative over-recovery of 14.64 percent.[27]

Gas-cost recovery for the current year is summarized below:

Percent Over-recovery (Under-recovery) by Class[28]

Firm	14.86
Interruptible	11.01
TOTAL SYSTEM	14.71

Pursuant to Minnesota Rules part 7825.2810, subp. 2D, Western provided a brief explanation of the deviation between gas cost recovery and actual gas costs. Western believes that the over-collection of gas costs was due to the combined effect of:

[25] Western submitted these revisions to correct its capacity release revenues, which the Company credits back to its ratepayers. A full explanation of why these revisions were made is on file at the Department as Western's response to DPS Information Request No. 2 in Docket No. G012/AA-95-911. Further, Western's confusion regarding the correct capacity release revenue amount resulted in the Company changing its true-up adjustment on customers' bills once in the September, 1995 PGA and again in the January, 1996 PGA. The true-up adjustments applied to customers' bills are shown on Attachment 13.

[26] The Department notes that this error was not identified in the auditor's report provided with the Company's filing pursuant to Minnesota Rules 7825.2820.

[27] This percent represents the accumulated over-recovery of $229,098 and is the actual amount on which the Department's 1994-95 true-up adjustment calculations are based.

[28] Supporting spreadsheet with detailed calculations is provided in Attachment 13.

- The Commission's suspension of the Company's PGA from July 1, 1994 through May 31, 1995 and changes in pipeline demand and supplier commodity prices that occurred over that time period. Due to the suspension of its PGA, Western was unable to pass these costs directly through to customers as it usually would. Specifically, the Company notes that Northern implemented changes in the 858, SBA, GSR, ANGST and PGA cost recovery surcharges during Western's PGA suspension period. Western also states that, beginning November 1, 1994, Northern implemented a change in Western's TF-12 entitlement levels. The Department notes that this change actually offset some of the over-recovery occurred due to other changes.

- Decreases in gas commodity prices during the suspension period that resulted in commodity prices that were considerably lower than the suspended commodity rate set by the Commission.

The Department believes that Western has correctly identified the suspension of its PGA as the main source of the Company's substantial over-recovery. In particular, the decrease in gas commodity costs resulted in a large over-recovery from Western's ratepayers (87 percent of the total over-recovery was due to commodity cost over-recovery). The Department provided a detailed discussion of the impacts of Western's suspended PGA in its February 15, 1995 compliance in Docket No. G012/AA-93-218.

In addition to the Company's revisions discussed above which affect Western's total costs during the reporting period, the Department recommends one modification to correct Western's true-up calculations. Specifically, the prior year's true-up balance for firm customers, as of June 15, 1995 should be increased by $250. This adjustment is necessary because Western made an error in calculating true-up revenues during the first two weeks of January, 1995. Based on the Department's calculations, the correct prior year's true-up balances are $1,321 for firm customers and $2,408 for interruptible customers. The Department's calculation of Western's true-up factors includes this modification. Western concurs with the Department's corrected true-up calculation (see Attachment 13) and has stated that it will apply the corrected true-up beginning with its February 1996 PGA.

b. Supplemental Reporting Requirements

In Docket No. G,E999/AA-94-762, the Commission ordered Western to submit, within 30 days of its Order, the information necessary to support the Company's over- and under-recovery of 1993-94 gas costs. The Company complied with this Order on January 31, 1996. Although Western's compliance was submitted late, the Department recommends that the Commission accept it because the Company's compliance is reasonable and does not have any impact on ratepayers.

In Docket No. G012/AA-93-218, the Commission required Western to include in its 1995 true-up all gas costs over-collected between July 1, 1994 and June 30, 1995. The Company complied with this requirement. The true-up adjustment includes gas costs over-collected during Western's PGA suspension period.

In Docket No. G012/M-93-1251, the Commission ordered Western to submit two additional reports in conjunction with the annual automatic adjustment report: (1) a report of all capacity-release transactions; and (2) a report of all penalties imposed on the Company by its pipelines supplies and all penalties imposed by the Company on its customers. The Department has reviewed the required reports and believes that they comply with the Commission Order. The Department summarizes the capacity-release and penalty reports submitted by all utilities in Part F of the instant report.

F. *COMMISSION REQUIRED REPORTS*

Pursuant to the Commission's Order in Docket No. G,E999/AA-91-653, the Department incorporated several summary reports in the 1993 and 1994 annual reports. These reports included the ranking of utilities in the following areas:

- average annual total bill per customer;
- total weighted-average-cost-of-gas (WACOG) per unit; demand costs of gas per unit;
- cost of gas storage per unit;
- commodity margin per unit;
- review of peak day demand profiles;
- summary of pipeline use of firm transportation capabilities in Minnesota;
- review of the number of suppliers used by each utility; and
- summary of the continuing transition costs resulting from FERC Order 636

In its Order in Docket No. G,E999/AA-94-762 the Commission required that the Department structure its 1995 annual automatic adjustment report in a fashion similar to the 1994 report. The Commission also required the Department to provide the following reports for the 1995 annual report:

- a brief summary of the utilities' treatment of lost and unaccounted-for gas;
- a list of each company's reserve margin percentage;
- a summary of utility filing requirements that have been added by the Commission since September 1, 1994;
- an analysis of People's and NMU's cost/benefit quantifications of the choice of UtiliCorp as a gas supplier.

For the instant report, the Department incorporates the Commission's Order requirements and several of the reports included in previous reports. Because some of these reports contain information which is not specifically required by Minnesota Rules, the Department issued information requests to all utilities to obtain necessary data.[29] Except where specifically identified, the summary reports in this section are developed from the data supplied by the companies in response to the Department's information requests. In order to comply with the Commission ordered reports listed above, the Department includes the following reports in its review of the gas utilities' 1994-95 annual reports:

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[29] The responses to these information requests are on file at the Department of Public Service. Please note that some of the information included in the companies' responses is proprietary.

1. average annual total bill per residential customer;
2. total WACOG, estimated versus actual;
3. commodity margin per unit;
4. cost of gas storage per unit;
5. review of peak day demand profiles and reserve margins;
6. pipeline daily delivery variance charges;
7. revenue from curtailment penalties;
8. summary of pipeline use for firm transportation capabilities in Minnesota;
9. review of the number of suppliers used by each utility;
10. summary of the transition costs resulting from Order 636;
11. summary of capacity-release activities in Minnesota;
12. annual auditor's report;
13. review of utilities' handling of lost-and-unaccounted-for-gas;
14. summary of utility filing requirements added by Commission; and
15. analysis of Peoples' and NMU's choice of UtiliCorp as a gas supplier.

1. *Average Annual Residential Customer Bills*

Using data supplied in response to an information request[30] the Department compared the average annual bill of residential customers for each regulated utility in Minnesota. This information is summarized in Graph 1 below and in Attachment 14. For comparison purposes, the Department developed a typical residential customer's annual bill for each utility by pipeline system based on:

- the customer charge;
- per-unit energy consumption rate; and
- average customer consumption of 140 Mcf per year.

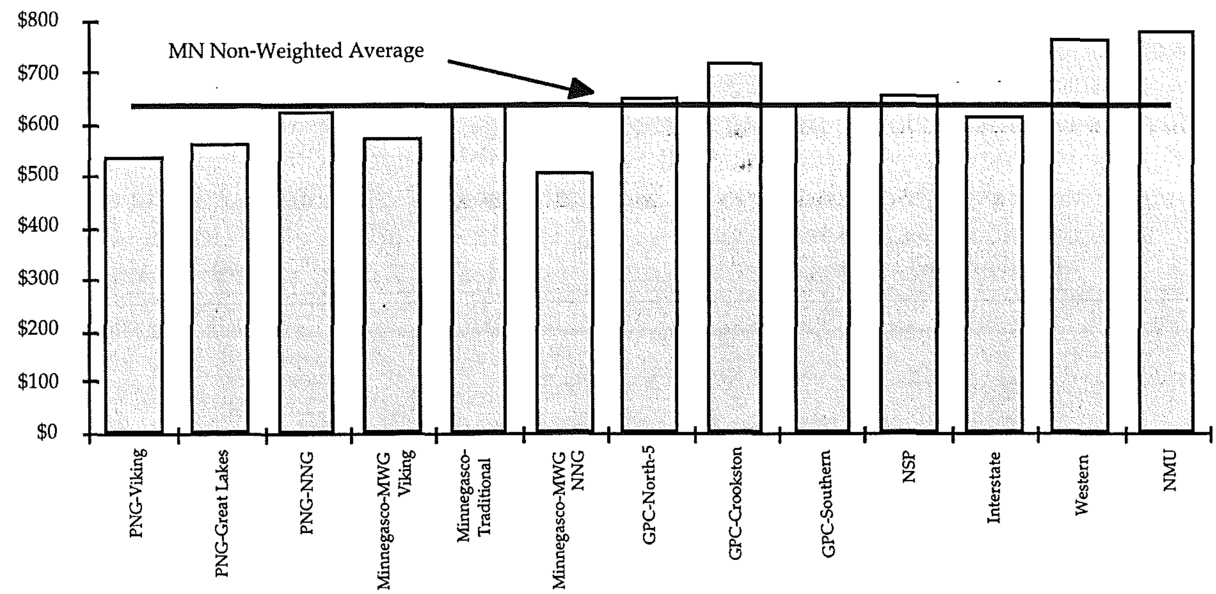
In general, a residential customer pays a fixed monthly customer charge and a per-unit energy consumption rate. The per-unit energy consumption rate can be broken down into non-gas and gas costs. The non-gas costs are referred to as the commodity margin (or gross margin) as approved by the Commission at the time of the utilities' most recent general rate case.

The cost of gas for a firm customer includes a demand cost of gas and a commodity cost of gas. The demand cost of gas is the amount a utility pays for the right to reserve pipeline capacity and various other services for the transportation of gas. Demand volumes change only with Commission approval in a miscellaneous demand-entitlement filing; however, as interstate pipelines change the *rates* they charge, Minnesota utilities pass these charges on to their customers. The commodity cost of gas, which generally refers to the cost of the gas itself that

[30] The Companies' responses to DPS Information No. 2 in the current docket are on file at the Department of Public Service.

customers use and the associated throughput charges for these volumes, changes frequently depending on the market. Graph 1 below illustrates the results of the Department's analysis.

GRAPH 1
AVERAGE RESIDENTIAL BILL 1994-95
BASED ON AVERAGE ANNUAL CONSUMPTION OF 140 MCF



As shown above, the non-weighted average customer bill using a consumption level of 140 Mcf is $635.47[31], reflecting a decrease of $78.96 from the 1993-94 average of $714.43. Graph 1 also shows that, based on a consumption level of 140 Mcf, average annual residential bills range from a high of $782.52 for customers served by NMU to the low of $502.60 for customers served by Minnegasco's Midwest Northern system. It should be noted that amounts shown in Graph 1 are not actual averages for customers on any system since actual averages for each utility depend on average consumption levels.[32]

The Department believes that two qualifications regarding the information provided in Graph 1 and Attachment 14 are necessary. First, the costs which utilities incur are often determined by a number of factors such as load factor, number of customers, the mix of firm and interruptible customers, number of available pipeline systems, weather, and past contracts with pipelines and suppliers which are still in effect.

31 See column 8 of Attachment 14 for individual utility average residential bills based on consumption of 140 Mcf per year. For consistency and comparison purposes, the Department chose to use an average consumption level of 140 Mcf to compare the utilities as used in previous reports.
32 See column 7 of Attachment 14 for individual utility's actual average residential bill based on utility's actual average residential consumption.

Second, the non-gas part of the rate is developed independently to reflect the cost of delivering service. This cost is a product of the service territory, customer mix and density, and other factors. The Department highlights some of these differences between utilities in the following sections.

To summarize, based on an average consumption of 140 Mcf per year, the average annual bill of $635.47 for residential customers represents a slight decrease from 1993-94.

2. *Comparison of Estimated versus Actual Weighted Average Gas Costs*

Since the cost-of-gas is the amount passed on to ratepayers in their bills, the Department believes it is important to review the companies' estimated price of gas purchases and its actual price of gas purchases. A comparison of the annual average of both the estimated and the actual weighted average cost of gas is contained in Table 6 below, shown from highest over-estimate to lowest under-estimate.

TABLE 6
Total Weighted Average Cost of Firm Gas
Estimated Versus Actual

Company	PGA[33]	Actual[34]	% Change
Peoples-Viking	$1.9546	$1.4056	39.06%
Western	$2.1115	$1.7118	23.35%
NSP[35]	$1.5654	*****PROPRIETARY**	**PROPRIETARY*****
Peoples-Northern	$1.6053	$1.5194	5.66%
Great Plains-Crookston	$1.4239	$1.3582	4.84%
Minnegasco-Northern	$1.6110	*****PROPRIETARY**	**PROPRIETARY*****
Minnegasco-Viking	$1.5025	*****PROPRIETARY**	**PROPRIETARY*****
Peoples-Great Lakes	$1.9632	$1.9312	1.66%
Great Plains-Northern	$1.3642	$1.3608	0.25%
Great Plains-Southern	$1.5319	$1.5327	-0.05%
Interstate	$1.4641	$1.4834	-1.30%
NMU	$1.7833	$1.8729	-4.78%
Non-Weighted MN Average	**$1.6567**	**$1.5577**	**6.36%**

Table 6 demonstrates a significant variance in the estimated and actual weighted-average-cost-of-gas calculations between companies. The greatest over-estimate of gas costs was by Peoples-Viking which over-estimated its gas costs by 39 percent during the reporting period (see Section E, part 6 for further details). (This

33 Supporting documentation is presented in the Quarterly Report Summary in Docket No. G999/PR-95-1349.

34 As reported in response to DPS Information Request No. 1

35 NSP's PGA WACOG includes peak shaving and is for July 1994-June 1995, while the reported actuals do not include peak shaving and are for June 1994 to May 1995. The Department calculated NSP's actual WACOG per NSP's true-up to be $1.5733.

level exceeded even that of Western, which had a suspended PGA.) The greatest under-estimate of gas costs was by NMU which under-estimated its gas costs by approximately 5 percent during the reporting period.

While the Department attempted to establish consistency in the utilities' responses, the Department notes that there may be some variation in the methods used by utilities to report actual costs. For instance, the actual monthly costs reported by a company may include various adjustments which correspond to gas delivered during an earlier reporting period. Also, the Department's information request did not specify whether to report purchases from suppliers or sales of gas to ratepayers and while theoretically these should be the same, the Department notes that such may not always be the case. However, the Department believes that the reported gas costs represent the price the utilities estimated and ultimately paid for gas supplies absent any producer demand costs and any related Order 636 costs.

3. *Per-Unit Non-Gas (Commodity) Margin Charged to Residential Customers*

Using the data collected from its information requests[36] to all gas utilities the Department developed a list of the annual 1994-95 per-unit non-gas (commodity) margins charged by each utility, by pipeline system, to residential customers. Commodity margins are calculated only at the time of rate cases and are based first on the Commission-approved interim rate and then on the Commission-approved final rate. The margin is then added to the combined estimates of demand and commodity costs for gas (as shown in the monthly PGA calculations submitted by each utility) and the true-up factor to obtain the per-unit cost of gas billed to the end-user. Table 7 below presents the Department's summary of the actual per-unit non-gas margins and the Minnesota non-weighted average using the combined averages for the Peoples, Minnegasco, and Great Plains systems. The information is presented in descending order, from the highest to lowest total system margin.

[36] The Companies' responses to DPS Information Request No. 2 in the current docket are on file at the Department of Public Service.

TABLE 7
Actual Per-Unit Non-Gas Margin Charge to Residential Customers[37]

Company	Non-Gas Cost Margin ($/MCF)
NMU	$1.81
Western	$1.76
Great Plains (Non-Wtd Ave)	$1.64
Crookston -Viking	$1.97
Viking- North 4	$1.62
NNG -South 13	$1.33
NSP	$1.44
Minnegasco (Non-Wtd Ave)	$1.12
Minnegasco - Midwest Northern	$1.29
Minnegasco - Northern	$1.12
Minnegasco - Viking	$0.96
Peoples (Non-Wtd Ave)	$1.12
NNG	$1.12
Viking	$1.12
Great Lakes	$1.12
Interstate	$0.81
MN Non-Weighted Average	**$1.34**

As shown above, NMU, Western, and Great Plains have the highest non-gas margin. This may be related the fact that these are small companies whose fixed costs are spread over fewer customers, however, specific reasons would be explored in individual company rate cases.

4. *Per-Unit Storage Cost of Gas*

Using the data from information requests[38] to all gas utilities, the Department compared the weighted average annual 1994-95 per-unit storage cost of gas with the results shown in Table 8. The companies are ranked in descending order with the highest average storage cycle cost per Mcf applying to NMU and the lowest to NSP.

[37] The reported figures represent a non-weighted average of the monthly margins in effect during the reporting period. See column 3 of Attachment 14.
[38] The companies' responses to DPS Information Request No. 1 in the current docket are on file at the Department of Public Service.

TABLE 8
Actual Per-Unit Storage Cost of Gas Comparison

Company	Storage Costs (per Mcf)
NMU	$2.3522
Minnegasco-Northern Area	***Proprietary***
Western	$1.9827
Peoples	$1.7157
Interstate	$1.6231
Great Plains	$1.5531
NSP	***Proprietary***
MN Weighted Average	**$1.9015**
MN Non-Weighted Average	**$1.8498**

As shown above, the actual storage cost ranged from a low of *****PROPRIETARY***** per Mcf for NSP, to a high of $2.3522 per Mcf for NMU. The non-weighted Minnesota average for all gas utilities was $1.8498. The Department notes that six of the seven utilities experienced decreases in per-unit storage costs from last year. Only NMU experienced an increase in average per-unit storage costs.[39] Overall, Minnesota's non-weighted per-unit average storage cost decreased by $0.62 from last year.

Figure 1 below presents the section of the monthly PGA reports and the information request sent in conjunction with the current report that addresses utility storage costs.

39 In its response to DPS Information Request No. 1 NMU reported costs of $54,841 in nine of the reporting months. No volumes were reported in these months. The remaining months had both dollars and volumes reported. In further discussion with the Department, NMU stated that it pays a monthly fee of $54,841 for its contracted storage on ANR and that this accounts for its increase costs. The Department also notes that in its response, NMU did not provide the breakdown of storage costs shown in Figure 1.

FIGURE 1
Storage Cost Components

Storage (1)	Price in WACOG $/Mcf (2)	Commodity $/MCF (3)	Injection $/MCF (4)	Withdrawl $/MCF (5)	Reservation $/MCF (6)	Capacity $/MCF (7)	Volume MCF (8)	Cost in Commodity (2) x (8) $ (9)
Storage 1	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Storage 2	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

As can be seen, the section asks the utilities to separate storage costs into its components. Despite the attempt to address the specific issue of consistency in reporting storage costs and to separate costs by component, the Department notes that there may still be some discrepancies in the companies' calculations of total-cycle storage costs. While Table 8 provides a general perspective on storage costs, the Department intends to continue working with the utilities to obtain consistent results.

In last year's report, the Department noted that the per-unit storage cost required certain qualifications. The Department believes that despite efforts to improve reporting, these qualifications remain relevant. The Department notes that the general trade-off between price and reliability also applies to storage supplies. Gas supplies in storage fields are a step removed from gas-producing fields and gathering facilities, thereby providing greater reliability of supplies during sustained cold periods which may affect wells in the production fields. While gas injected into storage during the non-heating season generally costs less than gas during the heating season (excluding outside factors affecting the natural gas industry, such as the implementation of Order 636 or other natural occurrences, which may lead to unusual price fluctuations), the added cost of using storage facilities and services often results in a higher final per-unit price of the storage gas rather than gas purchased during the heating season directly from a supplier. The trade-off between price and reliability should be an important consideration in each utility's gas portfolio decisions.

The Department also notes that the prices in the above table do not strictly correspond to either a commodity or a demand charge.[40] Rather, during this reporting period, some of the storage components are billed as demand charges by the gas utilities while the remaining components are shown as commodity charges. The Department merely attempted to obtain the figures and report them for comparative purposes.

[40] See Demand/Commodity Classification table included as DPS Attachment 5.

5. *Review of Gas Utilities' Peak-Day Demand Profiles*

The Department used the data in the information request responses[41] to develop a summary of each gas utility's peak day demand profile, load factor and reserve margin. Table 9 below presents a summary of this information.

Table 9
Firm Peak-Day Demand Profiles

Company	Firm Design Day Demand (Mcf)	Firm Peak Day Demand Entitlements (Mcf)	Annual Throughput (Mcf)	Annual Load Factor[42]	Reserve Margin %[43]
Interstate[44]	18,297	21,274	1,610,725	34.0%	13.99%
Western	5,212	6,002	493,528	31.2%	13.16%
NSP[45]	532,263	575,893	49,367,117	32.0%	7.58%
Minnegasco	1,068,089	1,117,962	95,202,554	32.3%	4.46%
Great Plains	28,394	28,814	2,754,291	30.0%	1.46%
NMU[46]	61,173	61,124	12,079,641	48.9%	-0.08%
Peoples[47]	174,003	151,540	18,847,086	35.3%	-14.82%
MN TOTALS	**1,887,431**	**1,962,609**	**180,354,942**	**33.2%**[48]	**3.83%**[49]

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41 The companies' responses to DPS Information Request Nos. 3, 4, and 5 in the current docket are on file at the Department of Public Service.

42 Load Factor = Daily average firm throughput (annual firm throughput divided by 365) divided by actual firm peak day demand.

43 Reserve Margin = firm design-day requirements divided by firm design-day entitlements (entitlements include contracted transportation and peak-shaving capacity).

44 In response to DPS information request No. 3, Interstate reported peak design day entitlement levels proposed in Docket No. G001/M-95-1393, pending before the Commission. The Department has modified Interstate's entitlements to correspond to the levels that were actually approved by the Commission for the reporting period.

45 In response to DPS information request No. 3, NSP reported total system amounts. The Department used allocation factor of .9028 to calculate Minnesota only values.

46 NMU does not separate Design Day Levels by classes. Therefore, the amounts reported in this table, including Annual Throughput, are for NMU's entire system.

47 In response to a DPS information request No. 5, Peoples reported a reserve margin of -1%. However, on August 23, 1995 (Docket No. G011/M-94-1082) the Commission approved a Design Day for 1994-95 of 162,189 Mcfs and Northern entitlements of 141,095 Mcfs. Using these numbers in combination with the numbers Peoples reported for its Great Lakes and Viking systems, the Department calculated its load factor and reserve margin.

48 This percent represents the weighted average of Minnesota LDCs load factors.

49 This percent represents the weighted average of Minnesota LDCs reserve margins.

As shown above, Minnesota's regulated gas utilities exhibit a firm load factor between 30.0 percent and 48.9 percent. Also, pursuant to the Commission's Order in Docket No. G,E999/AA-94-762, the Department reports the reserve margin percentage that is based on the ratio of firm design-day requirements to firm design-day entitlements which include contracted transportation and peak-shaving capacity. As shown in the above table, the reserve margin range from -14.82 percent to 13.99 percent.

The Department also used the data in the information request responses to develop a comparison of each gas utility's firm design peak-day demand entitlement to its actual firm peak-day use. Table 10 below presents a summary of this information.

TABLE 10
Comparison of Peak-Day Demand Usage

Company	Firm Peak Day Demand Entitlements (Mcf)	Actual Firm Peak Day Usage (Mcf)	Actual Peak Date in 1995
Great Plains	28,814	25,181	1/3/95
Interstate	21,274	12,986	2/10/95
Minnegasco	1,117,962	806,682	1/3/95
NMU	61,124	67,647	2/10/95
NSP	575,893	423,167	1/4/95
Peoples	151,540	146,158	1/3/95
Western	6,002	4,335	2/10/95
MN TOTALS	**1,962,609**	**1,486,156**	

As shown above, NMU was the only utility not able to meet actual firm peak-day sendout with its contracted level of firm capacity, but was able to successfully meet firm requirements with interruptible pipeline service. The Department is concerned with the fact that Peoples and NMU, both subsidiaries of UtiliCorp United Inc., maintain negative reserve margins and identify that, in situations where actual peak-day requirements exceed firm entitlements, they intend to use interruptible service or incur penalty charges to serve firm customers.[50]

[50] In response to DPS Information Request No. 5, the Peoples states its policy options to serve firm needs in excess of it firm entitlements as follows:
First, utilize the 45,000 MMBtu/day of Northern No-Notice Service (SMS); second if that does not satisfy requirements, then utilize overrun on NGPL which is generally available up to 40,000 MMBtu because it is a displacement type service; third utilize overrun service on Northern; or fourth, use

The Department's concern with utilities which maintain negative reserve margins is also voiced by other Minnesota gas utilities. Utilities which maintain positive reserve margins identify that utilities which maintain negative margins could have potential harmful effects by shifting pipeline costs to other utilities in the form of increased penalties[51], and reducing the pipelines' ability to meet firm obligations (i.e., potential shortages) to downstream utilities (see the responses of Great Plains', Western, Interstate, Minnegasco, and NSP to DPS Information Request No. 5(G) on file at the Department).

The Department recognizes that, in the past, both Peoples and NMU have successfully used interruptible service to serve firm customers in situations where actual peak-day requirements exceed firm entitlements. However, the Department believes that during extreme peak conditions, the best way to fully ensure delivery to firm customers is through firm service. The Department continues to have concerns about the practice of using interruptible service to serve firm peak needs and is also continuing to pursue this in Docket No. G011/M-95-1145.

6. *Daily Delivery Variance Charges (DDVCs)*

As mentioned in the previous section, in determining its blend of pipeline service, the utility decides the amount of entitlements and other related pipelines services required to reliably meet the needs of its firm customers. Under Order 636, each utility is required to "nominate" (tell the pipeline) the daily amount of expected gas use with a certain degree of accuracy. These nominations and the Utility's overall blend of services determine its ability to provide service on a daily basis especially during extreme weather fluctuations. In general, when a utility does not nominate its daily amounts (or cannot schedule the amount of capacity needed because of portfolio limitation) within a given percent (usually plus or minus five percent) of the firm entitlement level used[52], it faces additional pipeline charges (or penalties) known as positive or negative Daily Delivery Variance Charges (DDVCs). Once the variance exceeds a certain level (usually 10 percent greater than nomination), Northern imposes punitive DDVCs. Local Distribution Companies (LDCs) are required to nominate and use Northern's pipeline transportation in a responsible manner or face penalties, some of which are significant.[53]

Scheduling Charge gas on Northern. (See Peoples' response to DPS Information Request No. 5 (C) in Docket No. G, E999/AA-95-844 on file at the Department of Public Service.)

51 For instance, Great Plains responded to the Department's Information request by stating that such shifts could occur because the only probable way the "negative utilities" can meet firm requirements is by exceeding their entitlements on the pipelines. This action may cause the pipelines to go into operating limitations at an earlier stage than would be the case if all shippers were within firm entitlement. When operating limitations are called, shippers lose the "insurance cushions" they have paid for which are designed to mitigate exposure to imbalance penalties. With the insurance gone, the exposure to penalty costs is much greater.

52 The five percent accuracy parameter is a simple, although typical, example. There are several alternative accuracy parameters depending on such variables as the amount of contracted SMS and/or the announcement of a System Overrun Limitation (SOL) day declared by Northern.

53 For November 1994, the positive, negative, and punitive DDVCs were $1.00 per Mcf, $0.40 per Mcf, and $8.75 per Mcf, respectively.

In response to the demand entitlement filings filed in conjunction with FERC Order 636[54] , the Minnesota Commission ordered each regulated gas utility to provide a listing of the pipeline penalties it incurs. Table 11 below provides a summary of the pipeline penalties incurred during the 1994-95 reporting period.

TABLE 11
Daily Delivery Variance Charges

Company	Total Mcf	Total Dollars	Total Costs Incurred[55]	% of Total Costs Represented by Penalties
Peoples	145,496	$69,206	$53,760,201	0.1287%
Western	1,613	$778	$1,565,329	0.0497%
NMU	19,268	$8,879	$20,032,875	0.0443%
Great Plains	1,857	$962	$9,926,995	0.0097%
Minnegasco[56]	***Proprietary			Proprietary***
Interstate	808	$414	$6,247,031	0.0066%
NSP	0	0	$157,017,924	0.0000%
MN TOTALS	**235,622**	**$111,078**	**$584,748,229**	**0.0190%**

As shown above, the penalties incurred by gas utilities range from no reported penalties (NSP) to $69,206 (Peoples). This reflects Peoples' policy of using "Scheduling Charge gas on Northern" to meet the needs of firm customers.[57] Also, as illustrated in DPS Attachment 15, Peoples and NMU were the only utilities that incurred the highest-cost punitive DDVCs charge which further increased the commodity costs passed to ratepayers in the monthly PGAs. (The Department notes that, with the exception of Western, which absorbs the costs of DDVC penalties, gas utilities pass such costs on to ratepayers as commodity costs in the monthly PGAs.)

Since DDVC charges increase the costs which are paid by ratepayers, the Department recommends that the Commission continue to require utilities to provide detailed information of interstate pipeline penalties in the next annual automatic adjustment report. The Department will continue to monitor this information and identify any consistent uses of gas which increase costs to ratepayers that might warrant further review.

[54] Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1171, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-93-1093, and G012/M-93-1251.
[55] As reported in utilities' annual automatic adjustment filing.
[56] As reported in schedule F of Minnegasco's 1994-95 Annual Report. Responses to DPS Information Request No. 8 did not reflect a billing adjustment in November 1994.
[57] See footnote 50 above for the discussion of Peoples' policy options to serve firm needs in excess of it firm entitlements.

7. *Revenue from Curtailment Penalties*

As discussed in the section above, under FERC Order 636 LDCs are required to nominate and use Northern's pipeline transportation in a responsible manner or face penalties. In response to the transfer of responsibilities, LDCs must now, more than ever, establish the guidelines for responsible system use by its customers and enforce penalties for those who do not use the gas system in a responsible manner.

Minnesota LDCs have requested and received Commission approval to implement a number of tariff language changes that add several special conditions on nominations, balancing, and gas use during curtailments, introduce penalties to discourage customers from using gas when service is interrupted, and encourage customers to nominate and balance gas supplies responsibly. The specific tariff language has been approved and penalties have been imposed in several cases. Pursuant to the Minnesota Commission Orders,[58] each regulated gas utility reported the revenue received from the implementation of their Commission-approved curtailment provisions. Table 12 below provides a summary of the revenue from curtailment penalties incurred during the 1994-95 reporting period.

TABLE 12
Revenue from Curtailment Penalties

Company	Total Penalties	% of Total Penalties	Total Costs Incurred[59]	Penalties as a % of Total Costs Incurred
Peoples	$54,413	29.67%	$53,760,201	0.1012%
Minnegasco	$109,209	59.54%	$336,197,874	0.0325%
NSP	$19,785	10.79%	$157,017,924	0.0126%
MN TOTALS	**$183,407**	**100.00%**	**$546,975,999**	**0.0335%**

As shown above, the revenue from curtailment penalties imposed on interruptible (or "dual-fuel") customers by gas utilities ranges from no reported revenues (Interstate, Western, Great Plains, and NMU) to $109,209 (Minnegasco). The Department notes the fact that Peoples returns the revenues to customers by including the revenue in its annual true up. NSP and Minnegasco retained the revenue as sales revenue and did not include it in their annual true up. The Commission approved NSP's treatment of curtailment revenue in the Company's most recent gas rate case in Docket No. G002/GR-92-1186 since the revenue from curtailment penalty was imputed in test-year calculations. However, during the

58 Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1171, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-93-1093, and G012/M-93-1251.

59 As reported in utilities' annual automatic adjustment filing.

reporting period, Minnegasco's curtailment revenue treatment was not defined, but the issue was settled in the Company's most recent rate case in Docket No. G008/GR-95-700 and in the future, Minnegasco has agreed to return the curtailment revenues by including the revenue in its next annual true up.

The Department believes that curtailment penalties are intended to serve as a deterrent to irresponsible system use and not as a revenue source. Therefore, the Department recommends that the Commission continue to require utilities to provide detailed information on revenue collected from the implementation of curtailment provisions in the next annual automatic adjustment report.

8. *Peak-Day Pipeline Transportation Sources*

In its analysis of gas supply peak day reliability, the Department considered two factors: (1) the various pipeline companies that deliver gas to Minnesota gas utilities; and (2) the number of suppliers currently serving each gas utility (discussed in the next section). Table 13 below shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. Attachment 16 provides more details of the pipeline transportation sources for the gas utilities in Minnesota.

TABLE 13
Summary of Utilities' Gas Supply Transportation Sources
Total Minnesota Peak Quantity[60]

Pipeline	(Mcf per day)	Peak-Day Quantity Percent of Total
Northern Natural	1,266,862	64.5%
Viking Gas Transmission	69,972	3.6%
MIPC[61]	50,000	2.5%
Great Lakes Pipeline Co.	16,000	0.8%
Other Pipelines[62]	28,997	1.5%
Peak Shaving & Storage	530,780	27.0%
MN TOTALS	**1,962,610**	**100.0%**

60 The companies' responses to DPS Information Request No. 4 in the current docket are on file at the Department of Public Service. Proprietary Attachment 16 shows a company-by-company break-down of pipeline suppliers.

61 Minnesota Intrastate Pipeline Company, formerly known as MITS (Minnesota Intrastate Transportation System).

62 This includes ANR Pipeline Company (ANR), Centra Pipeline, and Williston Basin Interstate Pipeline (WBI).

Northern provides by far the greatest amount of peak-day capacity to Minnesota utilities, 64.5 percent of the total peak-day capacity. Depending on the specific situation of each utility, the number of different pipelines transporting gas to a particular utility for Minnesota ratepayers ranges from one to five. While some utilities may have greater options than others in their ability to lower costs by choice of pipeline sources, pipeline differentiation does not appear to impact reliability of service.

9. *Variety of Gas Suppliers*

The gas utilities displayed a certain amount of variety in their number of suppliers, ranging from two to twenty-four for firm supplies and from none to forty-one for interruptible sources. Table 14 below shows the number of firm long-term, firm spot, and interruptible suppliers for each utility.

*****PROPRIETARY TABLE 14 PROPRIETARY*****
Number of Suppliers

Company	Firm Long-Term Suppliers	Firm Spot Suppliers	Interruptible Suppliers
Great Plains			
Interstate			
Minnegasco			
NMU[63]			
NSP			
Peoples[64]			
Western			
MN TOTALS			

In choosing suppliers, all of the utilities reported that they carefully review past history and performance of potential third-party suppliers. Most of the utilities then proceed on a trial-and-error basis with those suppliers selected to determine if the supplier may indeed be relied upon for firm sales requirements. After the utilities are satisfied with suppliers' performance, they then sign contracts with particular suppliers based on lowest bids. The Department believes that no particular company gives cause to question reliability of service based on this information.

63***Proprietary***

64***Proprietary***

10. FERC Order No. 636 Transition Costs

Minnesota ratepayers experienced the results of the unbundling of transportation and gas supply services under FERC Order No. 636 by the rates charged from pipelines and by how each gas utility reacted to these changes. As seen in Table 13 above, Northern transports the most peak day gas in Minnesota, followed by Viking. Therefore, the Department's analysis focuses on these two pipelines, but also includes the total effects of all of the other pipelines. As mentioned previously, Northern's tariff changes affect both the demand and commodity costs charged to the Minnesota gas utilities in different ways for each utility.

A major issue under Order 636 is the allocation of transition costs. Since Minnesota receives the majority of its gas supplies through the Northern system and is one of the largest users of Northern's system, the Department illustrates how the transition costs were passed on to the state's seven regulated gas utilities. The Department notes the difficulty associated with determining transition costs since there is a difference of opinion among utilities as to which costs should fully be considered Order 636 transition costs. Table 15 shows how the transition costs affect these utilities.

TABLE 15
1994-95 Order 636 Transition Costs

Company		GSR/SBA/838	Direct Bills	Upstream Assignments	Total	% of Total
Minnegasco	*****Proprietary**					**Proprietary*****
NSP	*****Proprietary**					**Proprietary*****
Peoples		$1,689,849	$973,184	$3,430,342	$6,093,375	9.45%
NMU		$2,661,190	$198,660	$544,920	$3,404,770	5.28%
Interstate		$237,021	$216,419	$740,823	$1,194,262	1.85%
Great Plains		$221,290	$47,612	$417,300	$686,203	1.06%
Western		$52,672	$13,804	$0	$66,476	0.10%
MN TOTALS		**$20,691,929**	**$9,175,758**	**$34,639,956**	**$64,507,642**	**100.00%**

As shown in the table, transition costs of Minnegasco and NSP ratepayers comprise approximately 82 percent of all transition costs paid during the reporting period. Table 15 also shows total transition costs for the reporting period to be $64,507,642. In last year's report, the Department used the actual transition costs of $47,321,286 reported by utilities from November 1993 through October 1994 to project an annual cost for the 1993-94 period of $69,244,760. Thus, 1994-95 actual transition costs are slightly lower (6.8 percent) than estimated transition costs for 1993-94. The Department notes that Northern's transition costs will cover a period of between two and five years with the elimination of some transition costs (i.e. Account 191 on October 31, 1995) during the period.

TABLE 16
Cumulative Order 636 Transition Costs

		1994 Total	1995 Total	Cumulative Total	% of Total	
Minnegasco	***Proprietary					Proprietary***
NSP	***Proprietary					Proprietary***
Peoples		$5,652,267	$6,093,375	$11,745,642	10.50%	
NMU		$1,656,403	$3,404,770	$5,061,173	4.53%	
Interstate		$688,188	$1,194,262	$1,882,450	1.68%	
Great Plains		$565,794	$686,203	$1,251,997	1.12%	
Western		$49,289	$66,476	$115,765	0.10%	
MN TOTALS		**$47,321,286**	**$64,507,642**	**$111,828,928**	**100.00%**	

Table 16 above shows the cumulative transition costs paid by utilities in Minnesota as of June 30, 1995. As can be seen, these costs total to $111,828,928.

11. Capacity-Release

Capacity-release allows a company with transportation entitlements on a pipeline to relinquish unused and unnecessary capacity for variable periods of time and conditions. To date, every Minnesota gas utility has released capacity. The Commission requires all utilities to return all revenues from capacity-release transactions back to ratepayers through the annual true-up process.[65] Below is a summary of capacity-releases and the associated revenue which have been returned to ratepayers during the reconciliation period.

TABLE 17
CAPACITY RELEASE

Company	Actual Mcf	Total Revenues	Revenue Per Mcf	Total Costs Incurred[66]	% of Total Costs Represented by Capacity Release Total Revenues
Interstate	1,939,817	68,185	0.0352	$6,247,031	1.09%
Western	223,543	8,655	0.0387	$1,565,329	0.55%
Minnegasco	***Proprietary				Proprietary***
NSP	***Proprietary				Proprietary***
Peoples	5,512,867	220,571	0.0400	$53,760,201	0.41%
Great Plains	984,696	13,780	0.0140	$9,926,995	0.14%
NMU	2,134,837	26,805	0.0126	$20,032,875	0.13%
MN TOTALS	**74,152,323**	**2,704,335**	**0.0365**	**$584,748,229**	**0.46%**

65 Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1219, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-93-1248, and G012/M-93-1251.

66 As reported in utilities' annual automatic adjustment filing.

As shown in Table 17, and in more detail in Attachment 17, the large diversity in Minnesota for capacity-release transactions and represents the large diversity of capacity portfolios and individual situations of each gas utility. The revenues from capacity-release transaction range from $8,655 for Minnesota's smallest gas utility (Western) to ***PROPRIETARY*** for Minnesota's largest gas utility (Minnegasco). Interstate's capacity-release revenue of $68,185 (1.09 percent of total costs) represents the highest ratio of capacity-release revenue to total costs. A total of $2,704,335 in revenues was returned to ratepayers in the true-up calculation for all utilities releasing firm pipeline entitlement capacity.

As with the penalty portfolio decisions, the Department believes that future review of capacity-release transactions should prove to be useful and recommends that the Commission require all gas utilities to maintain detailed records of capacity-release transactions and report capacity-release volumes and revenues in the next annual automatic adjustment report.

12. Annual Auditor's Reports

The Commission's Order in the previous annual fuel report required that the auditors' reports filed by utilities pursuant to Minnesota Rule 7825.2820 "shall at least verify that the actual amounts included in the true-up calculations agree with the utility's accounting (revenue and expense) books and records." The Commission noted in its Order that the requirement would ensure more consistency and accountability in future gas utility filings and should help the parties to confirm that customers are being charged the correct gas costs.

In response to a Department information request,[67] each utility confirmed that an independent auditor verified that the actual amounts included in the true-up calculations agree with the utility's accounting (revenue and expense) books and records. In previous years, the Department conducted a one-month reconciliation of each Company's records. However, this year, the Department relied on the auditors' review for the true-up reconciliation to Company records.

Although some errors were discovered subsequent to the audits[68], these errors were relatively insignificant. Thus, the Department believes that the Commission should continue to require that the Companies have independent auditors verify that the actual amounts included in the true-up calculations agree with the utilities accounting books and records.

[67] The Department's Information Request No. 9.
[68] See individual write-ups for Interstate, NSP, and Western in Section E of the instant report.

13. Lost and Unaccounted for Gas

Pursuant to the Commission's Order for Docket No. G,E999/AA-94-762, the Department is required to provide a brief summary of the utilities' treatment of lost-and-unaccounted-for-gas (LAUG), including an analysis of the impact of the LAUG on rates whether through base rates or through a pass-through in the PGA. The Department's information request[69] asked the utilities how much LAUG was included in the utilities base cost of gas approved in their last rate case and to identify the specific amounts of LAUG assigned to each customer class in monthly PGAs. In response to the Department's information request question regarding how the utility handles LAUG, six of the seven utilities stated that LAUG is handled through the utility's base cost of gas and/or annual true-up filing.[70]

Table 18 presents the percent of total costs represented by LAUG for each gas utility from July 1, 1994 to June 30, 1995. The table also shows both the amount and estimated costs of LAUG, in Mcfs and dollars, experienced by the utilities during the reporting period.

TABLE 18
Lost and Unaccounted For Gas

	Volumes	Dollars	Cost per Mcf	Total Costs Incurred[71]	LAUG Dollars as % of cost incurred
Great Plains	57,641	$161,197	$0.36	$9,926,995	1.6238%
NMU	92,518	$149,330	$0.62	$20,032,875	0.7454%
NSP[2]	743,507	$1,161,209	$0.64	$157,017,924	0.7395%
Western	4,417	$7,557	$0.58	$1,565,329	0.4828%
Minnegasco[72]	582,910	$911,900	$0.64	$336,197,874	0.2712%
Interstate	5,279	$15,917	$0.33	$6,247,031	0.2548%
Peoples[73]	(488,169)	($1,409,731)	($0.34)	$53,760,201	(2.6223%)
MN TOTALS	**1,974,442**	**$997,380**		**$584,748,229**	**0.1706%**

69 The Department's Information Request No. 11.

70 Peoples does not list LAUG as a separate item and did not describe how it handles LAUG.

71 As reported in utilities' annual true-up report.

72 Minnegasco reported total system amounts in response to the Department's information request. The Department used .9028 allocator to determine Minnesota only values.

73 The Department notes that in its initial response to the information request Peoples stated that "lost and unaccounted for gas is considered to be less than 1% and is not considered as a separate item." However, in a subsequent response the Company provided the information reflected in the table above. Furthermore, in conversations with the Department, Peoples stated that lost and accounted for gas is included in the true-up factor and expressed concern over its ability to assign costs to LAUG when its sales to customers exceed its purchases from pipelines. Peoples stated that there are many adjustments associated with the purchases and sales of gas which make it difficult to determine LAUG.

As can be seen, LAUG dollars represented from 1.6 percent to -2.6 percent of the total costs incurred by the utilities during the reporting period. The volumetric amounts of LAUG range from -488,169 Mcf to 582,910 Mcf. The Department also notes that, in all but one case, additional costs ranging from $7,557 to $1,161,209 were past to customers in the true-up factor.

The Department recognizes that this does not account for a large money or volume impact on customer rates, however, if the Commission is interested in requiring further information from the companies on this issue, it might consider ordering Peoples to develop and implement a system which accurately presents LAUG for comparative purposes and having companies report this information in their future annual reports.

14. Summary of Utility Filing Requirements Added by Commission since September 1, 1994

In its previous annual report Order dated July 13, 1995, the Commission required that the Department include a summary of the utility filing requirements added by the Commission since September 1, 1994. The Department appreciates the assistance it received from Commission Staff and the Regulatory Information and Library Services Division of the Department in compiling this information. What follows is a list of docket numbers and the date the Order was issued. Analysis and/or mention of compliance with the Orders is covered in the individual utility write-ups found in Section E of this report. The list covers September 1, 1994 to August 31, 1995. A more complete description of these dockets is provided in Attachment 18.

TABLE 19
Summary of Commission Added
Utility Filing Requirements
(September 1, 1994 to August 31, 1995)

Docket Number	Company	Date Issued
G004/M-94-21	Great Plains	11/4/94
G004/M-94-22	Great Plains	11/4/94
G001/M-93-1219	Interstate	9/20/94
G008/GR-93-1090	Minnegasco	10/24/94
G008/M-94-853	Minnegasco	1/23/95
G008/M-93-1233	Minnegasco	1/23/95
G008/M-93-1234	Minnegasco	1/23/95
G007/M-94-20	NMU	12/9/94
G002/M-93-1149	NSP	12/9/94
G002/AI-94-838	NSP	3/16/95
G002/M-94-103	NSP	3/20/95
G002/M-94-938	NSP	8/11/95
G,E002/AI-94-729	NSP	8/16/95
G011/M-94-1082	Peoples	8/23/95
G012/AA-93-218	Western	5/16/95
G012/M-93-1251	Western	12/21/94
G,E999/AA-94-762	All Utilities	7/13/95

15. Analysis of Peoples' and NMU's Choice of UtiliCorp as a Gas Supplier

In Docket No. G011,007/AI-93-923, Peoples and NMU (the Companies) jointly requested that the Commission allow their parent company, UtiliCorp United, Inc. (UtiliCorp) to purchase gas and arrange transportation on their behalf on a consolidated basis. The Commission allowed the arrangement, but required Peoples and NMU to "annually quantify all benefits and costs of using UtiliCorp to provide the services rather than using other reasonable methods of procuring gas." This requirement was in response to concerns about whether UtiliCorp's costs of performing services for Peoples and NMU would, in practice, be reasonable compared to other alternatives for obtaining these services.

In the 1994 annual fuel report, Peoples and NMU listed some actions UtiliCorp had taken to lower their gas costs. Even though the Companies did not file a cost/benefit analysis and technically did not fully comply with the Commission's Order in Docket No. G011,007/AI-93-923, the Department indicated its belief in its April 5, 1995 letter updating the Commission about the 1994 annual fuel report that the information was sufficient at that time. The Department was aware that Peoples and NMU were then in the process of reorganizing their gas purchasing and PGA efforts under UtiliCorp and decided to focus on continuing to monitor the Companies' performances with its PGAs and gas purchasing. The Department discusses the Companies' performance in Section E of the instant report.

In Docket No. G,E999/AA-94-762, the Commission ordered the Department to provide a reasonable "analysis of Peoples' and NMU's cost/benefit quantification of the choice of UtiliCorp as a gas supplier." In the instant Docket, the Companies provided only information on certain savings that UtiliCorp claims to have provided for Peoples and NMU. However, there is still no information on UtiliCorp's costs or the costs of other alternatives to providing these services.

The Department requested detailed information from Peoples and NMU to allow the Department to comply with the Commission's Order in the previous annual fuel report. However, the Department believes that the Companies' response to these requests raises more concerns than it resolves. For example, in its Order in G011,007/AI-93-923, the Commission required both Peoples and NMU to provide in their next rate cases "a complete cost-benefit analysis showing why the Companies should continue to use UtiliCorp to provide the service." In its response to the Department's information request No. 12 in this case, UtiliCorp states that "UtiliCorp does not maintain a ongoing [sic] 'list of all system wide benefits' related to gas supply purchasing." This response raises the question of how Peoples or NMU will comply with the Commission's Order when the Companies file their next rate cases.

Further, the Department does not believe the information UtiliCorp has provided is sufficient to allow a complete analysis of the question of whether UtiliCorp is the best provider of gas purchasing and PGA services. While the filing lists ways that gas costs have decreased, it does not answer whether another provider could have either lowered gas costs even further or done so in a less expensive manner. Thus, the Department concludes that Peoples and NMU have not sufficiently quantified the costs and benefits of using UtiliCorp as a gas supplier.

In its June 29, 1995 meeting, the Commission questioned whether the UtiliCorp consolidation of NMU and Peoples gas purchasing is a good idea in practice. The Department has shared this question in light of the difficulties encountered with Peoples' and NMU's PGA and demand filings. While the Department has seen a large improvement in PGA filings since September 1995, there have continued to be problems with obtaining sufficient information to analyze Peoples' demand filing (Docket No. G011/M-95-1145). Based on these concerns, the Department believes it is still necessary to address the question of whether UtiliCorp is the best option for gas purchasing and PGA services. To do so, the Department believes that the Commission should require Peoples and NMU to provide more complete information about alternatives to using UtiliCorp.

In particular, the Department recommends that the Commission require Peoples and NMU, within 90 days of the Commission's Order in this Docket, to provide the following:

- an itemized list of all gas planning, supply, procurement and reporting services that UtiliCorp provides to Peoples and NMU;
- UtiliCorp's costs of providing these service; and
- the costs of obtaining these services from at least three other reliable providers.

The Department believes that the Commission needs to have a sufficient basis for continuing to allow UtiliCorp to provide these services for Peoples and NMU. While UtiliCorp may, in the end, be a reasonable option, in the increasingly competitive natural-gas industry, there may be superior alternatives for these companies to use for their customers.

16. Summary of Commission Required and Additional Reports

The Department believes that the reports required by the Commission provide additional information for both analysts and policy-makers. The Department notes that the reports in this section could not have been completed without the efforts of the regulated gas utilities. The Department appreciates their cooperation in developing the data for these reports. We hope that the above summary tables will provide a basis for future analyses of companies' operations and actions. Further, this information may prove to be useful as the Commission faces decisions on gas incentive plans in the future.

IV. SUMMARY OF DEPARTMENT'S RECOMMENDATIONS AND CONCLUSION

The Department concludes that, in general, electric and gas utilities largely complied with Minnesota Rules parts 7825.2810 through 7825.2830. The Department also recommends a number of specific items for future gas annual automatic adjustment reports to assure full compliance with Commission Orders and Minnesota Rules parts 7825.2700 and 7825.2910, and to improve accountability. In particular, the Department recommends that the Commission:

1. Accept the 1994-95 annual reports as filed by above-named gas and electric utilities as being in proper form and in general compliance with Minnesota Rules parts 7825.2390 through 7825.2920.

2. If it has not already done so, require Interstate to implement the recalculated true up within 30 days of the Commission's Order in this matter.

3. Accept Minnegasco's filing:

   - for Docket No. G008/M-92-777, regarding a cost/benefit analysis of the Natural Gas Pipeline of America (NGPL) Storage Program agreement's performance and a summary of all capacity improvements associated with the Northern agreement; and

   - for Docket No. G008/GR-93-1090, regarding the Company's report on its efforts to lower its demand and commodity costs of gas following its consolidation with Midwest Gas.

4. Require NMU and Peoples to provide the following within 90 days of the Commission's order in this matter:

   - an itemized list of all gas planning, supply, procurement and reporting services that UtiliCorp provides to Peoples and NMU;
   - UtiliCorp's costs of providing these service; and
   - the costs of obtaining these services from at least three other reliable providers.

5. Require Peoples to:

   - Report the following coincident and non-coincident peak-period information individually for all of the jurisdictions in which Peoples operates that are directly connected to the Northern system at the time of the Company's next annual fuel report:

- peak-period date(s);
- peak-period duration;
- peak-period sendout day; and
- the amount of interruptible supplies used to meet firm, peak-period requirements.

6. Accept Western's compliance filing for Docket No. G,E999/AA-94-762, regarding the information necessary to support the Company's over- and under-recovery of 1993-94 gas costs;

7. If it has not already done so, require Western to implement the recalculated true up within 30 days of the Commission's Order in this matter.

8. Require all utilities to:

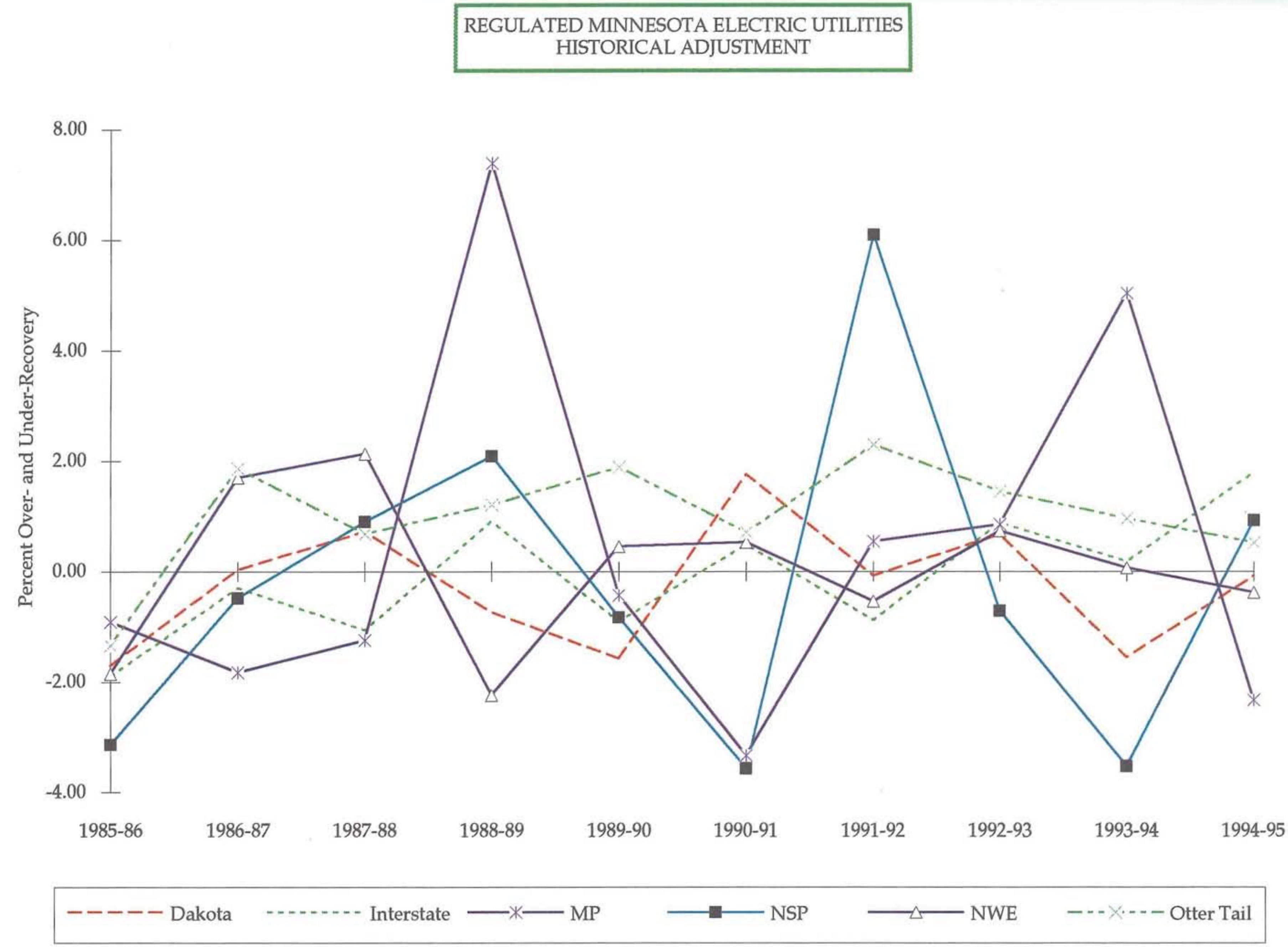
   - Continue to provide detailed information of interstate pipelines penalties in the next annual automatic adjustment report;

   - Continue to provide detailed information of revenue collected from the implementation of curtailment provisions in the next annual automatic adjustment report;

   - Maintain detailed records of capacity-release transactions and report capacity-release volumes and revenues in the next annual automatic adjustment report; and

   - Continue to require that the Companies have independent auditors verify that the actual amounts included in the true-up calculations agree with the utilities accounting books and records.

List of Attachments



MINNESOTA DEPARTMENT OF PUBLIC SERVICE

DAKOTA ELECTRIC ASSOCIATION

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(1.70%)
1986-87	0.03%
1987-88	0.72%
1988-89	(0.74%)
1989-90	(1.57%)
1991-91	1.76%
1991-92	(0.07%)
1992-93	0.67%
1993-94	(1.56%)
1994-95	(0.08%)
10-Year Avg.	**(0.25%)**

Total Cooperative Recovery, July 1994 - June 1995, By Month

(a) Month	(b) Total Cost Of Fuel	(c) Fuel Cost Revenue	(d) Over (Under) Recovery (c) - (b)	(e) Over (Under) Percentage (d) / (b)
July	4,756,006	4,754,231	(1,775)	(0.04%)
August	4,650,901	4,431,771	(219,130)	(4.71%)
September	4,510,857	4,550,866	40,009	0.89%
October	3,644,229	3,928,403	284,174	7.80%
November	4,009,096	3,844,344	(164,752)	(4.11%)
December	4,114,642	4,131,830	17,188	0.42%
January	4,272,993	4,142,286	(130,707)	(3.06%)
February	4,162,915	4,234,692	71,777	1.72%
March	3,646,957	3,775,409	128,452	3.52%
April	3,779,574	3,844,317	64,743	1.71%
May	3,530,830	3,470,077	(60,753)	(1.72%)
June	4,288,892	4,221,874	(67,018)	(1.56%)
Totals	**$49,367,892**	**$49,330,100**	**($37,792)**	**(0.08%)**

INTERSTATE POWER COMPANY - ELECTRIC

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(1.89%)
1986-87	(0.30%)
1987-88	(1.06%)
1988-89	0.91%
1989-90	(0.90%)
1991-91	0.49%
1991-92	(0.88%)
1992-93	0.89%
1993-94	0.18%
1994-95	1.80%
10-Year Avg.	(0.08%)

Total Company Recovery, July 1994 - June 1995, By Month

(a) Month	(b) Minnesota Cost Of Fuel	(c) Minnesota Fuel Cost Revenue	(d) Over (Under) Recovery (c) - (b)	(e) Over (Under) Percentage (d) / (b)
July	921,385	1,109,674	188,289	20.44%
August	930,676	1,031,155	100,479	10.80%
September	808,550	929,565	121,015	14.97%
October	824,301	865,506	41,205	5.00%
November	885,766	856,587	(29,179)	(3.29%)
December	942,643	826,938	(115,705)	(12.27%)
January	968,384	919,097	(49,287)	(5.09%)
February	838,718	919,866	81,148	9.68%
March	902,447	912,372	9,925	1.10%
April	929,138	810,931	(118,207)	(12.72%)
May	935,376	778,986	(156,390)	(16.72%)
June	864,244	984,255	120,011	13.89%
Totals	$10,751,629	$10,944,932	$193,303	1.80%

MINNESOTA POWER

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(0.91%)
1986-87	(1.82%)
1987-88	(1.24%)
1988-89	7.39%
1989-90	(0.43%)
1991-91	(3.33%)
1991-92	0.55%
1992-93	0.85%
1993-94	5.03%
1994-95	(2.33%)
10-Year Avg.	0.38%

Total Company Recovery, July 1994 - June 1995, By Month

(a) Month	(b) Total Cost Of Fuel	(c) Fuel Cost Revenue	(d) Over (Under) Recovery (c) - (b)	(e) Over (Under) Percentage (d) / (b)
July	5,469,542	5,565,339	95,797	1.75%
August	6,330,563	5,556,805	(773,758)	(12.22%)
September	6,127,371	5,748,973	(378,398)	(6.18%)
October	5,787,361	5,958,186	170,825	2.95%
November	6,737,936	6,681,110	(56,826)	(0.84%)
December	7,622,974	6,593,846	(1,029,128)	(13.50%)
January	7,498,507	7,040,632	(457,875)	(6.11%)
February	6,405,510	6,856,376	450,866	7.04%
March	7,730,611	7,400,931	(329,680)	(4.26%)
April	7,286,335	6,704,199	(582,136)	(7.99%)
May	6,387,567	6,481,684	94,117	1.47%
June	5,767,080	6,721,465	954,385	16.55%
Totals	$79,151,357	$77,309,546	($1,841,811)	(2.33%)

NORTHERN STATES POWER COMPANY (MINNESOTA) - ELECTRIC

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(3.13%)
1986-87	(0.48%)
1987-88	0.90%
1988-89	2.09%
1989-90	(0.83%)
1991-91	(3.56%)
1991-92	6.09%
1992-93	(0.71%)
1993-94	(3.52%)
1994-95	0.93%
10-Year Avg.	(0.22%)

Total Company Recovery, July 1994 - June 1995, By Month

(a)	(b)	(c)	(d)	(e)
Month	Minnesota Cost Of Fuel	Minnesota Fuel Cost Revenue	Over (Under) Recovery (c) - (b)	Over (Under) Percentage (d) / (b)
July	26,957,067	28,194,771	1,237,704	4.59%
August	26,751,602	27,335,064	583,462	2.18%
September	25,082,372	27,514,695	2,432,323	9.70%
October	22,085,066	23,791,228	1,706,162	7.73%
November	18,660,336	23,811,396	5,151,060	27.60%
December	21,172,089	24,117,242	2,945,153	13.91%
January	24,188,672	23,615,802	(572,870)	(2.37%)
February	22,943,155	20,479,272	(2,463,883)	(10.74%)
March	21,882,824	20,412,781	(1,470,043)	(6.72%)
April	21,783,959	20,494,559	(1,289,400)	(5.92%)
May	22,481,245	21,320,353	(1,160,892)	(5.16%)
June	28,155,368	23,670,717	(4,484,651)	(15.93%)
Totals	$282,143,755	$284,757,880	$2,614,125	0.93%

NORTHWESTERN WISCONSIN ELECTRIC COMPANY

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(1.85%)
1986-87	1.70%
1987-88	2.13%
1988-89	(2.24%)
1989-90	0.46%
1991-91	0.53%
1991-92	(0.54%)
1992-93	0.74%
1993-94	0.07%
1994-95	(0.38%)
10-Year Avg.	**0.06%**

Total Company Recovery, July 1994 - June 1995, By Month

(a) Month	(b) Minnesota Cost Of Fuel	(c) Minnesota Fuel Cost Revenue	(d) Over (Under) Recovery (c) - (b)	(e) Over (Under) Percentage (d) / (b)
July	1,541	1,427	(115)	(7.44%)
August	1,527	1,543	16	1.06%
September	1,434	1,576	142	9.89%
October	1,142	1,092	(50)	(4.38%)
November	1,076	1,007	(69)	(6.45%)
December	960	1,003	43	4.49%
January	1,100	1,117	18	1.59%
February	1,092	1,116	23	2.14%
March	1,035	1,043	8	0.80%
April	809	855	46	5.74%
May	1,105	1,000	(105)	(9.49%)
June	1,267	1,256	(12)	(0.93%)
Totals	**$14,088**	**$14,034**	**($54)**	**(0.38%)**

OTTER TAIL POWER COMPANY

Summary of Fuel Cost Recovery Since 1985-1986:

Year	Over (Under) Recovery
1985-86	(1.33%)
1986-87	1.87%
1987-88	0.68%
1988-89	1.21%
1989-90	1.89%
1991-91	0.71%
1991-92	2.30%
1992-93	1.45%
1993-94	0.96%
1994-95	0.52%
10-Year Avg.	**1.03%**

Total Company Recovery, July 1994 - June 1995, By Month

(a) Month	(b) Minnesota Cost Of Fuel	(c) Minnesota Fuel Cost Revenue	(d) Over (Under) Recovery (c) - (b)	(e) Over (Under) Percentage (d) / (b)
July	1,664,981	1,742,217	77,237	4.64%
August	1,873,279	1,745,722	(127,557)	(6.81%)
September	1,761,974	1,872,229	110,255	6.26%
October	1,888,403	1,817,012	(71,391)	(3.78%)
November	1,910,342	1,947,183	36,841	1.93%
December	1,965,246	2,133,569	168,324	8.57%
January	2,278,407	2,239,870	(38,537)	(1.69%)
February	2,099,060	2,229,733	130,673	6.23%
March	2,041,622	1,945,728	(95,894)	(4.70%)
April	1,761,272	1,862,219	100,946	5.73%
May	1,779,814	1,721,632	(58,182)	(3.27%)
June	1,890,417	1,776,373	(114,044)	(6.03%)
Totals	**$22,914,815**	**$23,033,487**	**$118,671**	**0.52%**

SYNOPSIS OF MINNESOTA'S ELECTRIC UTILITIES' FUEL RELATED POLICIES, PROCEDURES, COST-MINIMIZATION EFFORTS AND PROJECTIONS

	DAKOTA	INTERSTATE	MINNESOTA POWER	NORTHERN STATES POWER	OTTER TAIL
PROCUREMENT POLICIES:	Dakota's sole supplier is Cooperative Power Association (CPA) which is a generation and transmission cooperative.	Framework for Procurement: Power Production Dept is responsible for all fuel procurement except for jointly owned units where operator is responsible. They keep abreast of market conditions and maintain a file of potential suppliers.	Their practices are aimed at strategically minimizing the customers' current energy costs while being in compliance with current environmental regulations and, simultaneously, taking action to assure cost-effective compliance with future environmental requirements.	Policies direct that fuel and transportation will be purchased at the lowest possible cost within the constraints of environmental regulations, reliability of supply sources, operational compatability and consistency with NSP's inventory requirements.	Policy mandates the use of the competitive bidding process with regard to the procurement of fuel. Selection of the supplier is based on achieving the lowest cost commensurate with adequate reliability of supply, environmental compliance and compatability with boiler equipment.
DISPATCHING PROCEDURES:	Effective January 1, 1996, the boards of directors of CPA and Dairyland Power Cooperative (DPC) voted to support the integrated operation of their generation resources. For dispatch purposes all 17 CPA member cooperatives and all 28 DPC member cooperatives are treated as members of the joint CPA/DPC system. Dakota expects that with the integration of the power production resources of the two generation and transmission cooperatives, that savings of up to $60 million over the first ten years will be realized from joint dispatch and fuel procurement alone.	Dispatching is handled by its Energy Mgmt Center. Prices of purchased electricity are compared to marginal production costs of their individual available generating units in determining quantities of electricity to be purchased and generated. They have met economic dispatch goals by the purchase of economy and maintenance energy.	To ensure an adequate and economic supply of energy, MP uses a number of sophisticated real-time (dynamic) computer programs which assist with making decisions regarding which generating units to run and/or when to arrange a purchase or sale.	Policy is to closely monitor its load and intensively manage its generation system so as to provide the most economic loading of its own generating units. NSP also purchases power and energy when the cost is less than its own production cost. NSP operates a 14 computer, energy mgmt system (EMS). The program calculates the most economic combination of generation and purchases to serve native load and sales to other utilities.	Units are dispatched with the cheapest unit picking up load first and being backed off last. Operating constraints on the units must be closely followed. The levels of generation and purchases are adjusted hourly to minimize costs to OTP customers. The dispatchers have full authority to make purchases and sales of energy that will result in cost savings and as such have the responsibility to make economic transactions.
COST-MINIMIZING EFFORTS	Dakota has aggresively pursued load management and energy conservation efforts over the past several years.	Their goal is to procure fuel at the lowest possible cost commensurate with having an assured supply of fuel for	Because of current market conditions, MP's current practice is to have relatively short-term coal contracts.	Fuel Supply: Nuclear Fuel - Fuel costs at Monticello and P.I. are the 15th and 18th lowest out of	The total cost for energy purchases and generation will be minimized, while operating within the NERC and

	DAKOTA	INTERSTATE	MINNESOTA POWER	NORTHERN STATES POWER	OTTER TAIL
COST-MINIMIZING EFFORTS (continued)	Cooperative Power has improved the operation of its power plant and made financial changes that have reduced the cost of whoelsale power. As a result of the above, Dakota's rates are 11 percent lower than they were four years ago. CP's mine-mouth Coal Creek Generating Station is rated the fourth most efficient steam-electric power plant in the nation among 707 coal, oil, gas, and nuclear plants. The coal is obtained from Falkirk Mining Company which operates the mine. As a result of a recent revision of the mining plan, fuel supply cost will be reduced by approximately 10 percent over ten years.	plant operations. Everything is evaluated in terms of Cost per Million BTU delivered to their plants. Fuel input and output are monitored on a daily basis. Guidelines related to heat input, pressures, temperatures and other operating parameters were established over the years and deviations are noted so that corrective action can be taken as soon as practicable.	However, their transportation contracts are of a long-term nature. In August 1994, MP signed another agreement with Big Sky Coal Company for the period 1994 thru May 1997 for Boswell and Laskin. In 1994, MP signed a short-term agreement for 1995 with Kennecott Energy In 1993, MP signed agree-. ments with BN for the transportation of coal to Boswell and Laskin through 2003 and 2002 respectively. In 1992, MP signed a new agreement with the DM&IR for the transportation of coal to Laskin through 2002. MP uses a multi-discipline fuels procurement and strategy team to achieve fuel cost minimization and environmental compliance objectives. The team meets regularly to coordinate all related activities.	109 operating reactors in the U.S. Recent negotiations will reduce nuclear fuel capital expenditures by $29 million over next 5 years compared to 1993 forecast. Fossil Fuel - Recent negotiations will reduce both cost of coal and transportation. Power Production: Improvements to Existing Generating Plants - Various cost effective projects have helped NSP minimze costs and meet demand requirements. Future Generating Plant Improvements - The purpose is to optimize the economic dispatch of the generation equipment. Generating Plant Performance - Overall NSP remains above industry standards (cited are 13 different factors). Organizational/Financial Controls - Daily purchases low-cost energy on the spot market; GFIN was installed to provide plant analysis; and GEM is being installed to alalyze operating alternatives among various generating units.	MAPP guidelines. 100 % participation in MAPP POET (Procedure to Optimize Economic Transactions) program. This is an hourly MAPP program used by the dispatchers to either sell available energy, or realize fuel savings by buying energy from a cheaper unit. Generating facilities will be economically dispatched within operating constraints of units.
FUEL-COST PROJECTIONS	Assuming that CPA does not initiate the construction of a peaking plant in the next four years, the average cost of power should remain relatively constant. Costs may increase by about one percent during each of the first two years, then decrease by a slightly less amount each of the following two years.	Anticipates annual cost increases of 1.5 percent to 6 percent during specific years; however, Interstate projects a 15 percent decrease during 1999 due to the renegotiation of coal contracts.	**PROPRIETARY**	Fossil fuel prices will escalate by about 2 percent per year, and nuclear prices will hold relatively constant until the year 2000, when the price is projected to increase by 3 percent.	Fuel costs are projected to have a net increase of about 2.5 percent per year during this period; although individual years may see increases of 0.2 percent and 5 percent.

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Attachment 3
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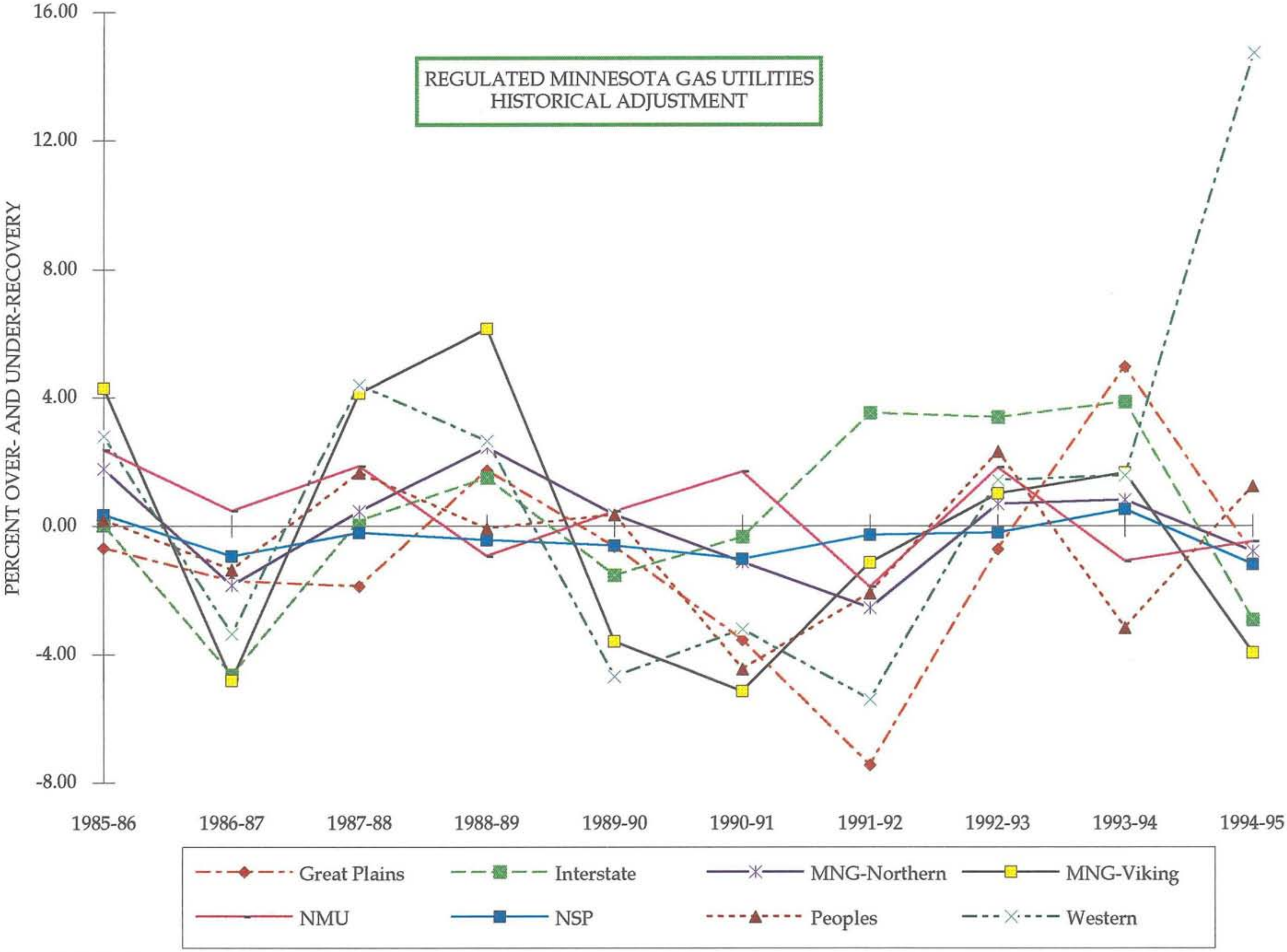

REGULATED MINNESOTA GAS UTILITIES
HISTORICAL ADJUSTMENT
PERCENT OVER- AND UNDER-RECOVERY
16.00
12.00
8.00
4.00
0.00
-4.00
-8.00
1985-86
1986-87
1987-88
1988-89
1989-90
1990-91
1991-92
1992-93
1993-94
1994-95
Great Plains
Interstate
MNG-Northern
MNG-Viking
NMU
NSP
Peoples
Western

Docket No. G,E999/AA-95-844
Attachment 5

Billing Classification Comparison
(Demand versus Commodity)

NNG SERVICES		NNG	PNG	IPW	NSP	MGC	WGI	GPNG	NMU
Throughput Services •	TF-12 Base	D	D	D	D	D	D	D	D
	TF-12 Var	D	N/A	D	D	D	D	D	D
	TF-5	D	D	D	D	D	D	D	D
	TFF	D	D	D	D	D	D	D	D
	TFX	D	D	N/A	D	D	N/A	D	N/A
	GSR Surcharge	D	C	D	D	D	D	D	D
	TCR surcharge	D	D	D	D	D	D	D	D
	TF12V-SBA Surcharge	D	D	C	D	D	D	D	D
	TF12B-SBA Surcharge	D	D	C	D	D	D	D	D
	TF5-SBA Surcharge	D	D	C	D	D	D	D	D
	TFX-SBA Surcharge	D	D	N/A	D	D	N/A	D	N/A
	STRANDED 858 Surcharge	D	D	D	D	D	D	D	D
	STRANDED 858 R.A.	D	D	D	D	D	D	D	D
	TF GRI DEMAND	D	D	D	D	D	D	D	D
Assigned Monthly Charges	ANGTS Direct Bill	D	C	D	D	D	D	D	D
	Account 191 Direct	D	C	D	D	D	D	C	D
CD-Merchant Function	CD-Merchant Function-Adm. Fee	C	C	C	C	C	N/A	C	C
	CD-Merchant Function-Commodity	C	C	C	C	C	N/A	C	C
Canadian Transportation Reservation (Assigned From Reverse Auction)	Nova Pipeline	D	C	N/A	N/A	N/A	N/A	N/A	N/A
	Foothills Pipeline	D	C	N/A	N/A	N/A	N/A	N/A	N/A
	Transcanada	D	C	N/A	N/A	N/A	N/A	N/A	N/A
	NBPL	D	C	N/A	D	N/A	N/A	N/A	N/A
	Great Lakes	D	C	N/A	D	N/A	N/A	N/A	N/A
	Pan Alberta	D	N/A	C	D	D	N/A	D	D
	Westcoast (Unigas)	D	N/A	C	D	D	N/A	D	D
	ANR-Carlton	D	N/A	C	N/A	N/A	N/A	N/A	N/A
	WGML I	D	N/A	N/A	D	D	N/A	D	D
	WGML II	D	N/A	N/A	D	D	N/A	D	D
	MOBIL	D	N/A	N/A	N/A	N/A	N/A	N/A	D
Balancing Service	SMS Reservation Charge	D	D	C	D	D	D	D	D
	SMS Commodity Charge	C	C	C	C	C	C	C	C
FDD Storage Service	FDD Reservation	D	C 1/	C	D	N/A	D	D	D
	FDD Capacity	D	C 1/	C	D	N/A	D	D	D
	FDD Injection	C	C 1/	C	C	N/A	C	C	C
	FDD Withdrawal	C	C 1/	C	C	N/A	C	C	C

1/ During the 1994-95 true-up period, Peoples only charges FDD to a jurisdiction when storage is used by that jurisdiction. Effect November 1, 1994, Peoples began assign all FDD associated charges as demand per its request in Docket No, G011/M-94-1082.

GLOSSARY

TERMS AND ACRONYMS	*DEFINITION*

ACA........."Annual Charge Assessment" by the Federal Energy Regulatory Commission (FERC) which is paid to the FERC to defray the cost of administering the agency.

ANGTS........."Alaskan Natural Gas Transmission System" is the combination of pipelines who were provided specific allowances by the U.S. government to provide additional supplies from north of the contiguous lower 48 states. Northern Natural maintained a deferred accounting procedure to prevent over or under collection of the costs assessed to them. With restructuring under Order 636, Northern is required to relinquish such operations to its shippers. Northern will now recover any remaining balance of costs in excess of revenues for the period ending October 31, 1993.

Brokered Reservation Charge This demand component of the PGA, which is reservation charges paid to our supplier of natural gas for transportation and other costs incurred to reserve upstream pipeline capacity to get gas.

DDVC........."Daily Delivery Variance Charge" is the penalty imposed by Northern Natural when a shipper's nominated receipt and delivery point volumes are not equal beyond the shipper's allowed 5 percent tolerance and any SMS service that the shipper may have contracted.

TFF demarcation point Northern has traditionally distinguished its Field Area transportation from its Market Area transportation. Northern's pipeline capacity, located south of Clifton, Kansas, is classified as Field Area transportation. Northern's pipeline capacity located north of Clifton is considered Market Area transportation. As part of the Northern Global Settlement approved by the FERC in Docket No. RS92-8-000, et. al. firm Field Area Transportation (TFF) was assigned to shippers based on their prorata share of field area capacity which is approximately equal to the amount of firm gas supply under contract from Northern's field area prior to the implementation of Order 636.

GRI........."Gas Research Institute" is a jointly sponsored research and development program which is funded by a surcharge granted by the FERC and collected from all pipelines. The GRI conducts research and development programs to benefit the entire natural gas industry.

GSR........."Gas Supply Realignment" costs are the expense of the pipeline to buyout, buydown and recognize price differentials of gas supply contracts beginning November 1, 1993 in light of the restructuring of the pipeline and the elimination of the merchant function. Northern is implementing a FERC approved surcharge to recover such costs. Northern is limited to recovering a maximum of $78 million of such costs over the next five years.

IGIC........."Interim Gas Inventory Charge" was a mechanism used to recover costs similar to those that will now be recovered in the GSR surcharge.

Litigation Exception Take-or-pay gas supply contract costs attributable to contracts in litigation or arbitration on March 31, 1989, and not included in TCR or ROP recovery mechanisms.

LMS........."Load Management Service" is Viking's no-notice service used to provide additional tolerances for shippers, above the allowed 5 percent tolerance.

New Services.........Effective November 1, 1992, Northern took an initial step to comply with Order 636 by separating previous levels of firm transportation (which reserved pipeline capacity) plus bundled sales services (e.g., Contract Demand, Seasonal Service, etc.) into unbundled transportation service.

MDQ........."Maximum Daily Quantity."

Order 636 Services.....Effective November 1, 1993, Northern implemented tariffs in response to the FERC Order 636 et. al. The implementation completes a fundamental transformation of the natural gas market which completely "unbundles" (or separates) gas transportation and sales. Since Northern had already begun its transition to an unbundled transportation-dominated system under "New Services," its Order 636 service portfolio continues most of its New Service offerings with refinements. See Attachment 1 for a full discussion of Northern's Order 636 service portfolio.

PGA (LDC's)........."Local Distribution Company's Purchased Gas Adjustment" is a mechanism used by regulated utilities to recover its "cost of energy." Minnesota Rules parts 7825.2390 to 7825.2920 enable regulated gas (and electric) utilities to adjust rates on a monthly basis to reflect changes in its "cost of energy" delivered to customers based upon costs authorized by the Minnesota Public Utilities Commission in the utility's most recent general rate case.

PGA (Pipelines')........"Pipeline's Purchased Gas Adjustment" was the mechanism previously used by the pipeline to prevent the over or under collection of gas costs used in the activities of the merchant function. Under Order 636, Northern no longer has a PGA.

SBA........."System Balancing Agreements" are between Northern and shippers on its system who agree to use their facilities and supplies at the demand of Northern to maintain system integrity when receipts and deliveries on the system are not in balance. Costs to Northern for such services are recovered with a surcharge.

SMS........."System Management Service" is Northern's no-notice service which provides additional tolerances for shippers, above the allowed 5% tolerance.

838 Stranded Costs...Stranded costs are the expenses incurred by the pipeline for third party pipeline capacity formerly used in providing merchant services. Such costs, similar to GSR costs, are recovered through the use of a surcharge.

SOL........."System Overrun Limitation" is a parameter or boundary that limits the use of SMS service on days which Northern's system integrity is threatened and SBA provisions are not adequate in maintaining pipeline operations.

TCR........."Transition Cost Recovery" mechanism was used to recover take-or-pay costs incurred prior to the implementation of Northern's IGIC and not addressed in FERC Docket No. RP88-259-046 which stipulates an agreement (New Services Settlement) to restructure Northern's services.

Throughput Services."Throughput Services: may be simply defined as the Total Aggregate MDQ for a shipper in Northern's Market Area. This Total Aggregate MDQ is the total of the individual MDQs of TF12-B, TF12-V, and TF5. A shipper's Total Aggregate MDQ is per contract with Northern, however, the three individual MDQs (used for billing purposes) are subject to limitations. First, TF5 cannot exceed 30 percent of Total Aggregate MDQ. Next the remainder is split between TF12-B and TF12-V on the contract's anniversary date with the TF12-B equaling total town border station (TBS) deliveries for the previous May through September. Thus, TF12-V would equal Total Aggregate MDQ less TF5 and TF12-B. These services are available in the Market Area only.

TF12-B.........Transportation - Firm for 12 months - Base Level. See Throughput Services.

TF12-V.........Transportation - Firm for 12 months - Variable Level. See Throughput Services.

TF5.........Transportation - Firm for 5 months. See Throughput Services.

TFF.........Transportation - firm - Field Area is capacity contracted for in the Field Area which allows Market Area customers to transport gas to the demarcation point - Clifton, Kansas.

TFX.........Transportation - Firm (Negotiable terms) is available to any shipper to acquire firm transportation services where the service needed is not conducive to the parameters set out under Throughput Services.

TI.........Transportation - Interruptible.

TOP........."Take-or-Pay" is the result of gas purchase contract clauses and declining gas sales by the pipelines before the onset of the open access/restructuring evolution in the gas industry. To acquire supplies in the 1970s, during curtailments, pipelines were agreeing to purchase contracts with penalty provisions if the minimum level of gas was not taken. When sales declined as industrial customers began using transportation rather than merchant services, pipelines incurred T-O-P penalties. Pipelines were granted recovery mechanisms by the FERC to remain in business without abrogating the contracts.

Great Plains Natural Gas Company

Summary of Gas Cost Recovery Since 1985:

Year	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1985	-0.30%	
1986	-0.69%	
1987	-1.73%	
1988	-1.88%	
1989	1.73%	
1990	-0.64%	
1991	-3.55%	-3.34%
1992	-7.44%	-7.61%
1993	-0.73%	-0.96%
1994	4.95%	5.06%
1995	-0.87%	-0.25%
11-YEAR AVG	-1.01%	

Total Company Recovery in 1995

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7)	(8) (6)-(7)	(9) (8)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)	PRIOR YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	ESTIMATED PROPANE 94-95	TOTAL OVER(UNDER) COLLECTIONS	CUM %
FIRM	$8,076,522	$8,161,955	($85,433)	-1.05%	$91,923	$6,489	$23,759	($17,270)	-0.21%
INTERRUPTIBLE	$2,910,608	$2,921,627	($11,020)	-0.38%	$992	($10,028)	$0	($10,028)	-0.34%
Total	$10,987,130	$11,083,583	($96,453)	-0.87%	$92,914	($3,539)	$23,759	($27,298)	-0.25%

Recovery in 1995 By Class - SOUTHERN SYSTEM

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7)	(8) (6)-(7)	(9) (8)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)	PRIOR YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	ESTIMATED PROPANE 94-95	TOTAL OVER(UNDER) COLLECTION	CUM %
FIRM	$4,291,452	$4,473,473	($182,021)	-4.07%	$51,044	($130,977)	$13,629	($144,606)	-3.23%
SVI	$556,333	$555,255	$1,078	0.19%	($1,423)	($345)	$0	($345)	-0.06%
LVI	$968,868	$967,002	$1,867	0.19%	$975	$2,842	$0	$2,842	0.29%
Total	$5,816,654	$5,995,730	($179,077)	-2.99%	$50,597	($128,480)	$13,629	($142,109)	-2.37%

Recovery in 1995 By Class - NORTHERN SYSTEM

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7)	(8) (6)-(7)	(9) (8)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)	PRIOR YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	ESTIMATED PROPANE 94-95	TOTAL OVER(UNDER) COLLECTION	CUM %
FIRM	$3,785,070	$3,688,482	$96,588	2.62%	$40,878	$137,466	$10,130	$127,336	3.45%
INTER.	$1,385,406	$1,399,370	($13,964)	-1.00%	$1,439	($12,525)	$0	($12,525)	-0.90%
Total	$5,170,476	$5,087,852	$82,624	1.62%	$42,318	$124,941	$10,130	$114,811	2.26%

Docket No. G,E999/AA-95-844
Attachment 7

Great Plains Natural Gas Company

COST RECOVERY BY CLASS AND COMPONENT - SOUTHERN SYSTEM

FIRM

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) RECOVERY ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) RECOVERY (%)
	COST RECOVERY	COST INCURRED		
TF12 Base:	407,195.62	442,146.12	-34,950.50	-7.90%
TF12 Variable:	101,051.41	107,732.84	-6,681.43	-6.20%
TFF:	552,759.36	593,597.78	-40,838.42	-6.88%
TF5:	182,079.81	197,098.00	-15,018.19	-7.62%
TFX November-March:	140,156.74	156,060.00	-15,903.26	-10.19%
TCR:	19,732.85	20,708.00	-975.15	-4.71%
GSR:	60,786.59	63,406.94	-2,620.35	-4.13%
SBA:	18,150.44	19,679.24	-1,528.80	-7.77%
Stranded 858 Surchg.:	67,676.15	89,773.48	-22,097.33	-24.61%
Strander 858 - RA	31,723.46	25,096.60	6,626.86	26.41%
SMS:	48,536.88	52,500.00	-3,963.12	-7.55%
FDD-1 Reservation:	75,662.20	81,905.28	-6,243.08	-7.62%
FDD-1 Capacity:	75,662.20	81,922.30	-6,260.10	-7.64%
Gr. Lakes Res. Fee:	4,872.79	5,299.64	-426.85	-8.05%
Brokered Res. Fee:	375,170.02	408,856.06	-33,686.04	-8.24%
ANGTS Direct Bill	7,948.19	7,092.00	856.19	12.07%
COMMODITY COSTS	2,122,287.38	2,120,598.84	1,688.54	0.08%
Peaking:	0.00	0.00	0.00	0.00%
SUB-TOTAL	4,291,452.09	4,473,473.12	-182,021.03	-4.07%
PRIOR YEAR TRUE-UP BALANCE			51,044.10	
TOTAL	4,291,452.09	4,473,473.12	-130,976.93	

SVI

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
COMMODITY COSTS	556,333.07	555,255.41	1,077.66	0.19%
SUB-TOTAL	556,333.07	555,255.41	1,077.66	0.19%
PRIOR YEAR TRUE-UP BALANCE			-1,422.87	
TOTAL			-345.21	

LVI

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
COMMODITY COSTS	968,868.40	967,001.76	1,866.64	0.19%
SUB-TOTAL	968,868.40	967,001.76	1,866.64	0.19%
PRIOR YEAR TRUE-UP BALANCE			975.32	
TOTAL			2,841.96	

Great Plains Natural Gas Company

COST RECOVERY BY CLASS AND COMPONENT- NORTHERN SYSTEM
FIRM

	COST RECOVERY	COST INCURRED	DOLLARS PRESENT YEAR OVER(UNDER) RECOVERY ($)	PERCENT PRESENT YEAR OVER(UNDER) COLLECTION (%)
FT-2 Reservation Chg.:	218,911.70	213,014.69	5,897.01	2.77%
Brokered Reservation Chg.:	1,477,532.41	1,380,187.59	97,344.82	7.05%
Seasonal Reservation Chg. VGT.:	34,887.53	33,872.32	1,015.21	3.00%
Seasonal Reservation Chg. NNG:				
TFX incl GRI:	177,742.17	173,400.00	4,342.17	2.50%
TFF:	38,097.86	36,885.45	1,212.41	3.29%
GSR:	14,832.26	14,274.00	558.26	3.91%
SBA:	4,460.19	2,712.00	1,748.19	64.46%
Stranded 858 Sur:	17,605.66	20,430.00	-2,824.34	-13.82%
Stranded 858-R.A.	8,066.33	5,598.00	2,468.33	44.09%
Commodity Cost:	1,792,933.86	1,787,099.00	5,834.17	0.33%
Propane Costs:	0.00	0.00	0.00	0.00%
Dekatherm Adj.	0.00	21,009.05	-21,009.05	-100.00%
SUB-TOTAL	3,785,069.97	3,688,482.10	96,587.18	2.62%
PRIOR YEAR TRUE-UP BALANCE			40,878.46	
TOTAL			137,465.64	

INTERRUPTIBLE

	(1) COST RECOVERY	(2) COST INCURRED	DOLLARS (3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	PERCENT (4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
Commodity Cost:	1,385,406.12	1,381,984.27	3,421.85	0.25%
Dekatherm Adj.:	0.00	17,385.91	-17,385.91	-100.00%
SUB-TOTAL	1,385,406.12	1,399,370.18	-13,964.06	-1.00%
PRIOR YEAR TRUE-UP BALANCE			1,439.07	
TOTAL			-12,524.99	

Great Plains Natural Gas Company

Recovery in 1995 - SOUTHERN SYSTEM
Recovery by Class and Component

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)
FIRM					
Demand		2,169,165	2,352,874	($183,710)	-7.81%
Commodity		2,122,287	2,120,599	$1,689	0.08%
	Total	4,291,452	4,473,473	($182,021)	-4.07%
INTERRUPTIBLE					
Demand					
Commodity		1,525,201	1,522,257	$2,944	0.19%
	Total	1,525,201	1,522,257	$2,944	0.19%

Recovery in 1995 - SOUTHERN SYSTEM
Recovery by Component and Class

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)
Demand					
Firm		2,169,165	2,352,874	-183,710	-7.81%
Interruptible					0.00%
	Total	2,169,165	2,352,874	-183,710	-7.81%
Commodity					
Firm		2,122,287	2,120,599	1,689	0.08%
Interruptible		1,525,201	1,522,257	2,944	0.19%
	Total	3,647,489	3,642,856	4,633	0.13%

Recovery in 1995 - NORTHERN SYSTEM
Recovery by Class and Component

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)
FIRM					
Demand		1,992,136	1,880,374	111,762	5.94%
Commodity		1,792,934	1,808,108	-15,174	-0.84%
	Total	3,785,070	3,688,482	96,588	2.62%
INTERRUPTIBLE					
Demand					
Commodity		1,385,406	1,399,370	-13,964	-1.00%
	Total	1,385,406	1,399,370	-13,964	-1.00%

Recovery in 1995 - NORTHERN SYSTEM
Recovery by Component and Class

		-1	-2	-3 (1) - (2)	(4) (3) / (2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) RECOVERY ($)	PRESENT YEAR OVER(UNDER) RECOVERY (%)
Demand					
Firm		1,992,136	1,880,374	111,762	5.94%
Interruptible				0	0.00%
	Total	1,992,136	1,880,374	111,762	5.94%
Commodity					
Firm		1,792,934	1,808,108	-15,174	-0.84%
Interruptible		1,385,406	1,399,370	-13,964	-1.00%
	Total	3,178,340	3,207,478	-29,138	-0.91%

NORTHERN SYSTEM:

The following is a summary of the factors other than weather which affected the demand recoveries the Northern System (note, however, that the total over/under recoveries contain weather related effects):

- **Brokered Reservation Charge:** This demand component of the PGA, which consists of reservation charges paid to the supplier of natural gas for transportation and other costs incurred to reserve upstream pipeline capacity to get gas to the Viking pipeline, was over recovered by $97,344.82 or 7.05 percent. Firm entitlement was increased in November 1994 for the months of June through September.

- **TFF:** This demand component of the PGA was over recovered by $1,212.41 or 3.29 percent due to some released TFF capacity which reduced its actual costs.

- **GSR:** This demand component of the PGA was over recovered by $558.26 or 3.91 percent. This was due to increases in NNG's demand component.

- **SBA:** This demand component of the PGA was over recovered by $1,748.19 or 64.46 percent. This was due to NNG's decrease in the demand component in November 1994 from $0.4720/Mcf/month to $0.1130/Mcf/month.

- **Stranded 858 Surcharge:** This demand component of the PGA was under recovered by $2,824.34 or 13.82 percent. The increased firm sales over projected sales was not enough to offset NNG's drastic decrease in the demand component in January 1995 from $0.8210/Mcf/month to $0.3310/Mcf/month.

- **Stranded 858 R.A.:** This demand component of the PGA was over recovered by $2,268.33 or 44.0 percent due to a major decrease in NNG's demand component in April 1995 from $0.2800/Mcf/month to $0.0005/Mcf/month.

SOUTHERN SYSTEM:

The following is a summary of the factors which affected the demand recoveries on the Southern System (note, however, that the total over/under recoveries contain weather related effects):

- **TF12 Base:** This demand component of the PGA, which is Northern Natural Gas Company's (NNG) transportation capacity reservation charge for base volumes, was under recovered by $34,950.50 or 7.90 percent. The TF12 Base was lowered from 6,306 Mcf to 6,232 Mcf in November 1994 with under recovery occurring for the summer months.

- **TF12 Variable:** This demand component of the PGA, which is NNG's transportation capacity reservation charge for variable volumes, was under recovered by $6,681.43 or 6.20 percent. The TF12 Variable was increased from 1,229 Mcf to 1,303 Mcf with over recovery occurring during the summer months and under recovery during the winter months.

- **TFF:** This demand component of the PGA was under recovered by $40,838.42 or 6.88 percent. Great Plains released some TFF capacity which reduced its actual costs.

- **TFX:** This demand component of the PGA was under recovered by $15,903.26 or 10.19 percent. the TFX was increased from 1,700 Mcf to 2,700 Mcf in November 1994.

- **GSR:** This demand component of the PGA was under recovered by $2,620.35 or 4.13 percent. NNG increased this demand component in January and April 1995.

- **SBA:** This demand component of the PGA was under recovered by $1,528.80 or 7.77 percent. NNG decreased this demand component in November 1994.

- **Stranded 858 Surcharge:** This demand component of the PGA was under recovered by $22,097.33 or 24.16 percent. NNG in January 1995, decreased this demand component from $0.8210/Mcf/month to $0.3310/Mcf/month.

- **Stranded 858 R.A.:** This demand component of the PGA was over recovered by $6,626.86 or 26.41 percent. This decreased firm sales were not enough to offset NNG's drastic decrease in the demand component in April 1995 from $0.2800/Mcf/month to $0.0050/Mcf/month.

- **Great Lakes Reservation Fee:** This demand component of the PGA was under recovered by $426.85 or 8.05 percent. In November 1994 this demand component went from $1.7930/Mcf/month to $1.788/Mcf/month.

- **Brokered Reservation Fee:** This demand component of the PGA was under recovered by 33,686.04 or 8.24 percent. In January 1995 brokered reservation fees increased having a tendency of under recovery.

Interstate Power (Gas) Company

Summary of Gas Cost Recovery Since 1986:

Year	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1986	0.01	
1987	-4.64	
1988	0.17	
1989	1.50	
1990	-1.54	
1991	-0.35	
1992	3.50	
1993	3.38	
1994	3.85	
1995	-2.93	
10 Year Average	0.30	-3.24%

Total Company Recovery in FY1995 By Class

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				(1) - (2)	(3) / (2)			(5)+(6)	(8)/(2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %
RATE 511	FIRM	$5,120,688	$5,214,875	($94,187)	-1.81%	($14,329)	($94,187)	($108,516)	-2.08%
RATE 524	SMALL INTERRUPTIBLE	$836,024	$914,138	($78,114)	-8.55%	($5,435)	($78,114)	($83,548)	-9.14%
RATE 526	LARGE INTERRUPTIBLE	$107,559	$118,019	($10,461)	-8.86%	$0	($10,461)	($10,461)	-8.86%
	Total	$6,064,271	$6,247,031	($182,760)	-2.93%	($19,764)	($182,762)	($202,525)	-3.24%

Docket No. G,E999/AA-95-844
Attachment 8

Interstate Power (Gas) Company

IPW GAS COST RECOVERY BY CLASS AND COMPONENT

RATE 511-FIRM

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND COST:	2,755,340.00	2,806,036.00	-50,696.00	-1.81%
COMMODITY COSTS:	2,365,347.00	2,408,839.00	-43,492.00	-1.81%
TOTAL	5,120,687.00	5,214,875.00	-94,188.00	-1.81%

RATE 524-SMALL INTERRUPTIBLE

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND COST:	225,534.00	246,611.00	-21,077.00	-8.55%
COMMODITY COSTS:	610,489.00	667,527.00	-57,038.00	-8.54%
TOTAL	836,033.00	914,138.00	-78,105.00	-8.54%

RATE 526-LARGE INTERRUPTIBLE

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND COST:	30,537.00	33,506.00	-2,969.00	-8.86%
COMMODITY COSTS:	77,022.00	84,513.00	-7,491.00	-8.86%
TOTAL	107,559.00	118,019.00	-10,460.00	-8.86%

Interstate
True-up Factors

	A Filed 9/1/95	B Filed 9/5/95	C Filed 1/15/96	D Implemented 3/1/96
Rate 511	0.0067	0.0062	0.0061	0.0061
Rate 524	0.0166	0.0154	0.0156	0.0156
Rate 526	0.0220	0.0206	0.0209	0.0209

SUMMARY OF GAS COST RECOVERY SINCE 1986:

Year Ended 9/1	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1986	1.76%	
1987	-1.86%	
1988	0.45%	
1989	2.43%	
1990	0.35%	
1991	-1.14%	-1.10%
1992	-2.56%	-2.63%
1993	0.67%	0.67%
1994	0.81%	0.77%
1995	-0.81%	-0.81%
10-YEAR AVERAGE	0.01%	-0.62%

RECOVERY IN 1995 BY ZONE AND BY CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				(3) / (2)		(3) + (5)		(6) + (7)	(8) / (2)		- (8) / (10)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	OTHER GAS COST CREDITS	TOTAL OVER(UNDER) COLLECTION	CUMULATIVE %	PROJECTED 1995-1996 SALES (DT)	TRUE-UP ADJUST. PER DT
SVF	$287,822,245	$291,065,083	($3,242,838)	-1.11%	$253,107	($2,989,731)	$0	($2,989,731)	-1.03%	101,564,700	$0.0294
LGS	$360,614	$370,632	($10,018)	-2.70%	$5,708	($4,310)	$0	($4,310)	-1.16%	101,800	$0.0423
SVDF	$22,725,187	$22,305,087	$420,100	1.88%	$15,913	$436,013	$0	$436,013	1.95%	12,580,400	($0.0347)
LVDF	$22,097,337	$21,980,903	$116,434	0.53%	($286,183)	($169,749)	$0	($169,749)	-0.77%	4,897,800	$0.0347
	$333,005,383	$335,721,705	($2,716,322)	-0.81%	($11,455)	($2,727,777)	$0	($2,727,777)	-0.81%	119,144,700	

Attachment 9

RECOVERY BY CLASS AND COMPONENT

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
SMALL VOLUME FIRM		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$134,884,710	$141,904,239	($7,019,529)	-4.95%
COMMODITY		$152,519,633	$149,084,729	$3,434,904	2.30%
PROPANE		$417,902	$76,115	$341,787	449.04%
	TOTAL	**$287,822,245**	**$291,065,083**	**($3,242,838)**	**-1.11%**
LARGE GENERAL SERVICE		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$170,929	$182,439	($11,510)	-6.31%
COMMODITY		$189,222	$188,123	$1,099	0.58%
PROPANE		$463	$70	$393	561.43%
	TOTAL	**$360,614**	**$370,632**	**($10,018)**	**-2.70%**
SMALL VOLUME DUAL FUEL		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$6,555	$0	$6,555	100.00%
COMMODITY		$22,718,632	$22,296,771	$421,861	1.89%
PROPANE		$0	$8,316	($8,316)	-100.00%
	TOTAL	**$22,725,187**	**$22,305,087**	**$420,100**	**1.88%**
LARGE VOLUME DUAL FUEL		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
COMMODITY		$22,097,337	$21,975,939	$121,398	0.55%
PROPANE		$0	$4,964	($4,964)	-100.00%
	TOTAL	**$22,097,337**	**$21,980,903**	**$116,434**	**0.53%**

RECOVERY BY COMPONENT AND CLASS

			RECOVERY	COST INCURRED	OVER(UNDER) RECOVERY	PERCENT OVER(UNDER) RECOVERY
DEMAND	SVF		$134,884,710	$141,904,239	($7,019,529)	-4.95%
DEMAND	SDVF		$6,555	$0	$6,555	100.00%
DEMAND	LGS		$170,929	$182,439	($11,510)	-6.31%
		TOTAL	**$135,062,194**	**$142,086,678**	**($7,024,484)**	**-4.94%**
COMMODITY	SVF		$152,519,633	$149,084,729	$3,434,904	2.30%
COMMODITY	LGS		$189,222	$188,123	$1,099	0.58%
COMMODITY	SVDF		$22,718,632	$22,296,771	$421,861	1.89%
COMMODITY	LVDF		$22,097,337	$21,975,939	$121,398	0.55%
		TOTAL	**$197,524,824**	**$193,545,562**	**$3,979,262**	**2.06%**
PROPANE	SVF		$417,902	$76,115	$341,787	449.04%
PROPANE	LGS		$463	$70	$393	561.43%
PROPANE	SVDF		$0	$8,316		
PROPANE	LVDF		$0	$4,964	($4,964)	-100.00%
		TOTAL	**$418,365**	**$89,465**	**$328,900**	**367.63%**
TOTAL DEMAND AND COMMODITY			**$333,005,383**	**$335,721,705**	**($2,716,322)**	**-0.81%**

SUMMARY OF GAS COST RECOVERY SINCE 1986:

Year ended 9/1	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1986	4.29%	
1987	-4.82%	
1988	4.12%	
1989	6.14%	
1990	-3.60%	
1991	-5.15%	
1992	-1.15%	
1993	1.00%	-0.39%
1994	2.97%	-0.63%
1995	-3.96%	-4.01%
10-YEAR AVERAGE	-0.02%	-1.68%

NOTE: 1986 through 1993 numbers are reported for total Midwest Gas Company. The 1994 & '95 numbers are reported for Minnegasco's Viking pipeline only.

RECOVERY IN 1995 BY ZONE AND BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)	(6) (3) + (5)	(7)	(8) (6) + (7)	(9) (8) / (2)	(10)	(11) - (8) / (10)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	OTHER GAS COST CREDITS	TOTAL OVER(UNDER) COLLECTION	CUMULATIVE %	PROJECTED 1994-1995 SALES (DT)	TRUE-UP ADJUST. PER DT
FIRM	$404,581	$423,969	($19,388)	-4.57%	$3,348	($16,040)	$0	($16,040)	-3.78%	154,600	$0.1038
DUAL FUEL	$71,588	$71,830	($242)	-0.34%	($3,592)	($3,834)	$0	($3,834)	-5.34%	32,800	$0.1169
	$476,169	$495,799	($19,630)	-3.96%	($244)	($19,874)	$0	($19,874)	-4.01%	187,400	

RECOVERY BY CLASS AND COMPONENT

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
FIRM			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
	DEMAND		$174,982	$195,250	($20,268)	-10.38%
	COMMODITY		$229,599	$228,719	$880	0.38%
		TOTAL	$404,581	$423,969	($19,388)	-4.57%

			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DUAL FUEL						
	COMMODITY		$71,588	$71,830	($242)	-0.34%
		TOTAL	$71,588	$71,830	($242)	-0.34%

RECOVERY BY COMPONENT AND CLASS

			RECOVERY	COST INCURRED	OVER(UNDER) RECOVERY	PERCENT OVER(UNDER) RECOVERY
DEMAND	FIRM		$174,982	$195,250	($20,268)	-10.38%
		TOTAL	$174,982	$195,250	($20,268)	-10.38%
COMMODITY	FIRM		$229,599	$228,719	$880	0.38%
COMMODITY	Dual Fuel		$71,588	$71,830	($242)	-0.34%
		TOTAL	$301,187	$300,549	$638	0.21%
TOTAL DEMAND AND COMMODITY			$476,169	$495,799	($19,630)	-3.96%

MINNEGASCO
Compliance Filing- Docket No. G-008/GR-93-1090

Former Midwest - Northern

Prepared by: Joe Klenken

Demand Cost PGA history

General Firm customers

	$/Therm
Aug.93	$0.15338
Sep.	$0.15309
Oct.	$0.15560
Nov.	$0.15560
Dec.	$0.15660
Jan.94	$0.15029
Feb.	$0.15300
Mar.	$0.15300
Apr.	$0.15375
May	$0.15289
Jun.	$0.15031
Jul.	$0.14791
Aug.	$0.14791
Sep.	$0.13737
Oct.	$0.14068
Nov.	$0.14301
Dec.	$0.14301
Jan.95	$0.14178
Feb.	$0.14182
Mar.	$0.14182
Apr.	$0.14228
May	$0.13986
Jun.	$0.14031
Jul.	$0.13878
Aug.	$0.13878
Sep.	$0.13713
Oct.	$0.13647
Nov.	$0.12575
Dec.	$0.12570

SUMMARY OF GAS COST RECOVERY SINCE 1986:

Year	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1986	2.36%	
1987	0.46%	
1988	1.86%	
1989	-0.95%	
1990	0.44%	
1991	1.68%	1.26%
1992	-1.91%	-1.96%
1993	1.81%	1.79%
1994	-1.11%	-0.93%
1995	-0.51%	-0.54%
10-YEAR AVERAG:	0.41%	-0.08%

RECOVERY IN 1995 BY ZONE AND BY CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				(3) / (2)		(3) + (5)		(6) + (7)	(8) / (2)		- (8) / (10)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	OTHER GAS COST CREDITS	TOTAL OVER(UNDER) COLLECTION	CUM %	PROJECTED 1994-1995 SALES (Ccf)	TRUE-UP ADJUST. PER Ccf
GS	$15,413,564	$15,645,098	($231,534)	-1.48%	$796	($230,738)	($3,618)	($234,357)	-1.50%	50,210,600	$0.00467
LGS	$464,990	$507,986	($42,996)	-8.46%	$24	($42,972)	($109)	($43,080)	-8.48%	1,506,700	$0.02859
LARGE VOLUME	$1,469,142	$1,456,024	$13,118	0.90%	$124	$13,242	($31)	$13,211	0.91%	435,410	$0.00007
INTERRUPTIBLE	$2,582,266	$2,423,768	$158,498	6.54%	($1,459)	$157,039	($1,021)	$156,018	6.44%	14,164,710	($0.01101)
	$19,929,962	$20,032,876	($102,914)	-0.51%	($515)	($103,429)	($4,779)	($108,208)	-0.54%	66,317,420	

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RECOVERY BY CLASS AND COMPONENT

		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
GENERAL SERVICE (Residentail, Commercial FGS, and Industrial FGS)		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$7,142,768	$7,997,043	($854,275)	-10.68%
COMMODITY		$8,270,796	$7,648,054	$622,742	8.14%
	TOTAL	**$15,413,564**	**$15,645,097**	**($231,533)**	**-1.48%**
LARGE GENERAL SERVICE **(Commercial LGS and Industrial LGS)**		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$205,726	$277,220	($71,494)	-25.79%
COMMODITY		$259,264	$230,766	$28,498	12.35%
	TOTAL	**$464,990**	**$507,986**	**($42,996)**	**-8.46%**
LARGE VOLUME		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
DEMAND		$1,273,512	$1,284,366	($10,854)	-0.85%
COMMODITY		$195,630	$171,658	$23,972	13.96%
	TOTAL	**$1,469,142**	**$1,456,024**	**$13,118**	**0.90%**
INTERRUPTIBLE		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
COMMODITY		$2,582,266	$2,423,768	$158,498	6.54%
	TOTAL	**$2,582,266**	**$2,423,768**	**$158,498**	**6.54%**

RECOVERY BY COMPONENT AND CLASS

		RECOVERY	COST	OVER(UNDER) RECOVERY	PERCENT OVER(UNDER) RECOVERY
DEMAND	RESIDENTIAL,	$7,142,768	$7,997,043	($854,275)	-10.68%
DEMAND	COMMERCIAL LGS	$205,726	$277,220	($71,494)	-25.79%
DEMAND	LARGE VOLUME	$1,273,512	$1,284,366	($10,854)	-0.85%
	TOTAL	**$8,622,006**	**$9,558,629**	**($936,623)**	**-9.80%**
COMMODITY	RESIDENTIAL,	$8,270,796	$7,648,054	$622,742	8.14%
COMMODITY	COMMERCIAL LGS	$259,264	$230,766	$28,498	12.35%
COMMODITY	INTERRUPTIBLE	$195,630	$171,658	$23,972	13.96%
COMMODITY	LARGE VOLUME	$2,582,266	$2,423,768	$158,498	6.54%
	TOTAL	**$11,307,956**	**$10,474,246**	**$833,710**	**7.96%**
TOTAL DEMAND AND COMMODITY		**$19,929,962**	**$20,032,875**	**($102,913)**	**-0.51%**

Northern States Power (Gas) Company

G002/AA-95-918

As Amended November 2, 1995

Summary of Gas Cost Recovery Since 1986:

FYE	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY		
1986	0.34%			
1987	-0.95%			
1988	-0.22%			
1989	-0.45%			
1990	-0.62%			
1991	-1.04%			
1992	-0.29%			
1993	-0.21%	*	***Proprietary***	Revised from 0.32% =***Proprietary***
1994	0.52%	*	***Proprietary***	Revised from 0.39% =*** Proprietary***
1995	-1.21%	-0.88%		
10-YEAR AVG	-0.41%			

Total Company Recovery % Over/Under

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7) (6)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %
FIRM	$136,155,287	$137,499,097	($1,343,810)	-0.98%	$201,579	($1,142,231)	-0.83%
INTERRUPTIBLE	$18,963,483	$19,518,827	($555,344)	-2.85%	$308,301	($247,043)	-1.27%
Total	$155,118,770	$157,017,924	($1,899,154)	-1.21%	$509,880	($1,389,274)	-0.88%

Recovery by Class

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7) (5)+(6)	(8) (7)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %
Residential (F)	$86,182,544	$87,184,617	($1,002,073)	-1.15%	$176,733	($1,002,073)	($825,340)	-0.95%
Comm/Indus (F)	$47,054,164	$47,391,828	($337,664)	-0.71%	$82,236	($337,664)	($255,428)	-0.54%
Large General (F)	$2,918,579	$2,922,652	($4,073)	-0.14%	($57,390)	($4,073)	($61,463)	-2.10%
Sm Interr	$5,711,662	$5,736,864	($25,202)	-0.44%	($1,101)	($25,202)	($26,303)	-0.46%
Lg Interr	$13,251,821	$13,781,963	($530,142)	-3.85%	$309,402	($530,142)	($220,740)	-1.60%
TOTAL	$155,118,770	$157,017,924	($1,899,154)	-1.21%	$509,880	($1,899,154)	($1,389,274)	-0.88%

Northern States Power (Gas) Company

Recovery by Class by Component

Residential

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)
Demand	$37,557,028	$38,338,787	($781,759)	-2.04%
Commod & Peak Shav.	$48,625,516	$48,845,830	($220,314)	-0.45%
Total	$86,182,544	$87,184,617	($1,002,073)	-1.15%

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Comm/Indust

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
Demand	$20,478,544	$20,922,646	($444,102)	-2.12%
Commod & Peak Shav.	$26,575,620	$26,469,182	$106,438	0.40%
Total	**$47,054,164**	**$47,391,828**	**($337,664)**	**-0.71%**

Large General

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
Demand	$851,447	$863,508	($12,061)	-1.40%
Commod & Peak Shav.	$2,067,132	$2,059,144	$7,988	0.39%
Total	**$2,918,579**	**$2,922,652**	**($4,073)**	**-0.14%**

Small Inter

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
Commod & Peak Shav.	$5,711,662	$5,736,864	($25,202)	-0.44%
Total	**$5,711,662**	**$5,736,864**	**($25,202)**	**-0.44%**

Large Inter

	(1)	(2)	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
	COST RECOVERY	COST INCURRED		
Commod & Peak Shav.	$13,251,821	$13,781,963	($530,142)	-3.85%
Total	**$13,251,821**	**$13,781,963**	**($530,142)**	**-3.85%**

TRUE UP FACTORS

(Over) Under	Residential	Commercial/Industrial	Large General Service Commodity	Large General Service Demand	Small Interruptible	Large Interruptible and Interdepartmental	Total (Over) Under
Remain. Bal.	($176,733)	($82,236)	$60,328	($2,938)	$1,101	($309,402)	($509,880)
Current Bal.	$1,002,073	$337,664	($7,988)	$12,061	$25,202	$530,142	$1,899,154
Total	$825,340	$255,428	$52,340	$9,123	$26,303	$220,740	$1,389,274
Budgeted Ccf	340,335,579	181,598,654	16,431,800	1,204,980	38,046,124	63,338,270	640,955,407
Factor	$0.00243	$0.00141	$0.00319	$0.00757	$0.00069	$0.00349	

Factors Implemented in November PGA

Northern States Power (Gas) Company

TRUE-UP FACTORS CALCULATED	A Used 11/94-8/95	B Implemented 9/2/95	C Implemented 10/2/95	D Implemented 11/2/95
Residential	-0.00185	0.00282	0.00270	0.00243
Commercial & Industrial	-0.00166	0.00189	0.00176	0.00141
Large Gen. Service-Commodity	0.01096	0.00205	0.00205	0.00319
LGS-Demand	-0.02127	0.02447	0.02374	0.00757
Small Volume Interruptible	0.00498	-0.00122	-0.00122	0.00069
Large Volume Interruptible	0.01343	0.00201	0.00201	0.00349

Northern States Power (Gas) Company

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As Amended November 2, 1995

Recovery by Component and Class

	Cost Recovery	Cost Incurred	Present Year Over (Under) Recovery	Percent Over (Under) Recovery
Demand				
Residential	$37,557,028	$38,338,787	($781,759)	**-2.04%**
Comm/Indus	$20,478,544	$20,922,646	($444,102)	**-2.12%**
LGS	$851,447	$863,508	($12,061)	**-1.40%**
TOTAL	$58,887,019	$60,124,941	($1,237,922)	**-2.06%**

	Cost Recovery	Cost Incurred	Present Year Over (Under) Recovery	Percent Over (Under) Recovery
Commodity and Peak Shaving				
Residential	$48,625,516	$48,845,830	($220,314)	**-0.45%**
Comm/Indus	$26,575,620	$26,469,182	$106,438	**0.40%**
LGS	$2,067,132	$2,059,144	$7,988	**0.39%**
SVI	$5,711,662	$5,736,864	($25,202)	**-0.44%**
LVI	$13,251,821	$13,781,963	($530,142)	**-3.85%**
TOTAL	$96,231,751	$96,892,983	($661,232)	**-0.68%**

Northern States Power (Gas) Company

REVISED REMAINING BALANCE AT 6/30/95 OF 1993/94 TRUE-UP BALANCE CARRYFORWARD

PROPRIETARY

Northern States Power (Gas) Company

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As Amended November 2, 1995

PROPRIETARY

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Attachment 12

Peoples Natural Gas Company

Summary of Gas Cost Recovery Since 1986:

Year	PRESENT YEAR PERCENT- OVER (UNDER) RECOVERY	CUMULATIVE PERCENT- OVER (UNDER) RECOVERY
1986	0.18%	
1987	-1.37%	
1988	1.66%	
1989	-0.09%	
1990	0.35%	
1991	-4.46%	
1992	-2.10%	-3.95%
1993	2.32%	0.01%
1994	-3.18%	-3.17%
1995	1.23%	0.73%
10 -YEAR AVERAGE	-0.55%	-1.60%

Total Company Recovery in 1995 By Supplier

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)	(6)	(7) (5)+(6)	(8) (8)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %
NNG	$50,556,903	$49,662,426	$894,477	1.80%	($259,108)	$894,477	$635,369	1.28%
GREAT LAKES	$2,117,568	$2,524,389	($406,821)	-16.12%	($13,787)	($406,821)	($420,608)	-16.66%
VIKING	$1,687,612	$1,513,191	$174,421	11.53%	$1,385	$174,421	$175 806	11.62%
TOTALS	$54,362,083	$53,700,006	$662,077	1.23%	($271,510)	$662,077	$390,567	0.73%

Peoples Natural Gas Company

Total Recovery in 1993 By Class

NORTHERN NATURAL GAS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
			(1) - (2)	(3) / (2)			(5)+(6)	(8)/(2)		(7)/(9)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %	SALES VOLUMES	TRUE-UP BILL CREDIT (SURCHARGE)
GS/SVI/LVI	$46,241,038	$45,364,117	$876,921	1.93%	($254,025)	$876,921	$622,896	1.37%	18,553,223	0.0336
JT-COMMODITY	$302,663	$346,415	($43,752)	-12.63%	$2,397	($43,752)	($41,355)	-11.94%	159,163	(0.2598)
JT-DEMAND	$1,489,571	$1,428,263	$61,308	4.29%	($7,480)	$61,308	$53,828	3.77%	104,940	0.5129
SLV (FT-DEMAND)	$2,523,631	$2,523,631	$0	0.00%	$0	$0	$0	0.00%		
TOTALS	**$50,556,903**	**$49,662,426**	**$894,477**	**1.80%**	**($259,108)**	**$894,477**	**$635,369**	**1.28%**		

GREAT LAKES

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
			(1) - (2)	(3) / (2)			(5)+(6)	(8)/(2)		(7)/(9)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %	SALES VOLUMES	TRUE-UP BILL CREDIT (SURCHARGE)
GS	$1,390,412	$1,653,796	($263,384)	-15.93%	($15,470)	($263,384)	($278,854)	-16.86%	642,009	(0.4343)
SVI/LV COMMODITY	$710,950	$854,104	($143,154)	-16.76%	$1,418	($143,154)	($141,736)	-16.59%	336,630	(0.4210)
JT DEMAND	$16,206	$16,489	($283)	-1.72%	$265	($283)	($18)	-0.11%	8,220	(0.0022)
TOTALS	**$2,117,568**	**$2,524,389**	**($406,821)**	**-16.12%**	**($13,787)**	**($406,821)**	**($420,608)**	**-16.66%**		

VIKING

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)
			(1) - (2)	(3) / (2)				(5)+(6)	(8)/(2)		(7)/(9)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	CURRENT YEAR TRUE-UP OVER(UNDER) ENDING BALANCE	REFUNDS PER PUC ORDER IN G011/AA-95-###	TOTAL OVER(UNDER) COLLECTION	CUM %	SALES VOLUMES	TRUE-UP BILL CREDIT (SURCHARGE)
RESIDENTIAL	$1,165,577	$1,028,080	$137,497	13.37%	($40,822)	$137,497	$12,684	$109,359	10.64%	589,262	0.1856
SVI/LV COMMODITY	$522,035	$485,111	$36,924	7.61%	$42,207	$36,924	$6,513	$85,644	17.65%	300,574	0.2849
TOTALS	**$1,687,612**	**$1,513,191**	**$174,421**	**11.53%**	**$1,385**	**$174,421**	**$19,197**	**$195,003**	**12.89%**		

NORTHERN NATURAL GAS SYSTEM

TOTAL NNG SYSTEM

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
TF-12	$7,367,940	$7,954,750	$0	($586,810)	-7.38%
TF-12	$51,060	$56,041	$0	($4,981)	-8.89%
TF-5	$1,750,530	$2,563,834	$0	($813,304)	-31.72%
TFX	$1,129,662	$850,215	$0	$279,447	32.87%
TFF	$3,798,910	$3,792,183	$0	$6,727	0.18%
TCR	$265,469	$285,245	$0	($19,776)	-6.93%
SMS CHARGE	$227,488	$257,345	$18,753	($11,104)	-4.31%
STRANDED 858	$1,069,329	$960,377	$0	$108,952	11.34%
SBA CHARGE	$211,339	$192,943	$27,276	$45,672	23.67%
PEAK SHAVING	$24,042	$0	$0	$24,042	100.00%
	$0	$0	$0	$0	100.00%
COMMODITY	$34,532,250	$33,347,452	$82,852	$1,267,650	3.80%
DAILY SCHEDULING CHARGES	$0	($54,413)	$0	$54,413	-100.00%
CAPACITY RELEASE	$0	($543,549)	$0	$543,549	-100.00%
SUBTOTAL	$50,428,019	$49,662,423	$128,881		0.00%
RECOVERY FROM SM. VOL. TRANS.	$128,881	$0			100.00%
TOTAL(PRESENT YEAR)	$50,556,900	$49,662,423		$894,477	1.80%
1993-94 TRUE-UP	$2,096,409	$2,355,517		($259,108)	-11.00%
		1994-95 TRUE-UP AMOUNT =		$635,369	

DEMAND

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
TF-12	$4,844,309	$5,431,119	$0	($586,810)	-10.80%
TF-12	$51,060	$56,041	$0	($4,981)	-8.89%
TF-5	$1,750,530	$2,563,834	$0	($813,304)	-31.72%
TFX	$1,129,662	$850,215	$0	$279,447	32.87%
TFF	$3,798,910	$3,792,183	$0	$6,727	0.18%
TCR	$265,469	$285,245	$0	($19,776)	-6.93%
SMS CHARGE	$227,488	$257,345	$18,753	($11,104)	-4.31%
STRANDED 858	$1,069,329	$960,377	$0	$108,952	11.34%
SBA CHARGE	$211,339	$192,943	$27,276	$45,672	23.67%
TOTAL(PRESENT YEAR)	$13,348,096	$14,389,302		($995,177)	-6.92%

COMMODITY

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
COMMODITY	$34,532,250	$33,347,452	$82,852	$1,267,650	3.80%
PEAK SHAVING	$24,042	$0	$0	$24,042	100.00%
DAILY SCHEDULING CHARGES	$0	($54,413)	$0	$54,413	-100.00%
TOTAL(PRESENT YEAR)	$34,556,292	$33,293,039		$1,346,105	4.04%

GREAT LAKES GAS SYSTEM

TOTAL

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
T-17 DEMAND	$77,243	$81,050	$0	($3,807)	-4.70%
FT-075 RES. FEE	$57,439	$58,285	$0	($846)	-1.45%
COMMODITY	$1,982,886	$2,385,054	$0	($402,168)	-16.86%
DAILY SCHEDULING CHARGES	$0	$0	$0	$0	0.00%
CAPACITY RELEASE	$0	$0	$0	$0	0.00%
SUBTOTAL	$2,117,568	$2,524,389	$0		
RECOVERY FROM SM. VOL. TRANS.	$0	$0			
TOTAL(PRESENT YEAR)	$2,117,568	$2,524,389		($406,821)	-16.12%
1993-94 TRUE-UP	($152,278)	($138,491)		($13,787)	9.96%
		1994-95 TRUE-UP AMOUNT =		($420,608)	

DEMAND

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
T-17 DEMAND	$77,243	$81,050		($3,807)	-4.70%
FT-075 RES. FEE	$57,439	$58,285		($846)	-1.45%
TOTAL(PRESENT YEAR)	$134,682	$139,335		($4,653)	-3.34%

COMMODITY

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
COMMODITY	$1,982,886	$2,016,061		($33,175)	-1.65%
PEAK SHAVING	$0	$0		$0	0.00%
DAILY SCHEDULING CHARGES	$0	$0		$0	0.00%
TOTAL(PRESENT YEAR)	$1,982,886	$2,016,061		($33,175)	-1.65%

VIKING GAS SYSTEM

TOTAL

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
FT-2 DMG CHARGE	$85,602	$85,104		$498	0.59%
FT-2	$7,522	$0		$7,522	100.00%
FT-3	$17,632	$0		$17,632	100.00%
COMMODITY	$1,576,855	$1,428,086		$148,769	10.42%
DAILY SCHEDULING CHARGES	$0	$0		$0	0.00%
CAPACITY RELEASE	$0	$0		$0	0.00%
SUBTOTAL	$1,687,611	$1,513,190	$0		
RECOVERY FROM SM. VOL. TRANS.	$0	$0			
TOTAL(PRESENT YEAR)	$1,687,611	$1,513,190		$174,421	11.53%
1993-94 TRUE-UP	$22,973	$21,588		$1,385	6.42%
		1994-95 TRUE-UP AMOUNT =		$175,806	

DEMAND

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
FT-2 DMG CHARGE	$85,602	$85,104		$498	0.59%
FT-2	$7,522	$0		$7,522	100.00%
FT-3	$17,632	$0		$17,632	100.00%
TOTAL(PRESENT YEAR)	$110,756	$85,104		$25,652	30.14%

COMMODITY

OVERALL	COST RECOVERY	COST INCURRED	SV TRANS REC	PRESENT YEAR	% OVER/UNDER
COMMODITY	$1,576,855	$1,428,086		$148,769	10.42%
PEAK SHAVING	$0	$0		$0	0.00%
DAILY SCHEDULING CHARGES	$0	$0		$0	0.00%
TOTAL(PRESENT YEAR)	$1,576,855	$1,428,086		$148,769	10.42%

Western Gas Utilities

(as amended by Western and the Department)

Summary of Gas Cost Recovery Since 1986:

Year	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
1986	2.79%	
1987	-3.36%	
1988	4.38%	
1989	2.64%	
1990	-4.69%	
1991	-3.22%	
1992	-5.41%	
1993	1.43%	
1994	1.57%	
1995	**14.71%**	**14.64%**
10-YEAR AVG	1.08%	

Total Company Recovery % Over/Under

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
			(1) - (2)	(3) / (2)		(3)+(5)	(6)/(2)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER(UNDER) COLLECTION ($)	PRESENT YEAR OVER(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER(UNDER) BEGINNING BALANCE	TOTAL OVER(UNDER) COLLECTION	CUM %
Firm	$1,729,386	$1,505,669	$223,717	14.86%	$1,321	$225,038	14.95%
Interruptible	$65,233	$58,766	$6,468	11.01%	($2,408)	$4,060	6.91%
Total	$1,794,619	$1,564,435	$230,185	14.71%	($1,087)	$229,098	14.64%

Docket No. G,E999/AA-95-844
Attachment 13

GAS COST RECOVERY BY CLASS AND COMPONENT

(as amended by Western and the Department)

FIRM	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
TF12-BASE	$223,345	$200,685	$22,660	11.29%
TF12-VARIABLE	$13,830	$20,660	($6,831)	-33.06%
TF5	$112,475	$104,346	$8,129	7.79%
TFF	$183,000	$169,749	$13,251	7.81%
TCR	$4,787	$4,715	$72	1.54%
SMS	$11,302	$10,500	$802	7.64%
GSR	$18,914	$18,003	$911	5.06%
858 SURCHARGE	$39,478	$27,029	$12,449	46.06%
SBA	$14,409	$6,640	$7,769	117.01%
GRI	$11,203	$9,290	$1,913	20.59%
ANGTS	$2,190	$692	$1,498	216.42%
PGA (ACCT 191)	$1,809	$2,730	($921)	-33.72%
FDD Capacity	$24,006	$22,965	$1,041	4.53%
FDD TFF	$0	$6,870	($6,870)	-100.00%
FDD- Reserv	$24,054	$22,965	$1,089	4.74%
COMMODITY	$1,035,929	$847,103	$188,825	22.29%
Transport	$0	$28,965	($28,965)	-100.00%
SUB-TOTAL	$1,720,731	$1,503,909	$216,822	14.42%
Misc. Adjustments (see text for explanations)	$8,655	$1,760	$6,895	
ADJUSTED SUB-TOTAL	$1,729,386	$1,505,669	$223,717	14.86%
True-Up Balance as of June, 1995			$1,321	
TOTAL			$225,038	

INTERRUPTIBLE	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER(UNDER) COLLECTION (%)
COMMODITY COSTS:	$65,233	$58,766	$6,468	11.01%
SUB-TOTAL	$65,233	$58,766	$6,468	11.01%
True-Up Balance as of June, 1994			($2,408)	
TOTAL			$4,060	

	TOTAL TRUE-UP AMOUNT Refund(Collection)	PROJECTED SALES (MCF)	TRUE-UP PER MCF Refund(Collection)
Firm	$225,038	545,000	0.4129
Interruptibl	$4,060	25,000	0.1624

Western Gas Utilities

True-up factors calculated

	A	B	C	D
	As Initially Filed	Implemented Sept. 1995 PGA	Implemented Jan. 1996 PGA	Implemented Feb. 1996 PGA
Firm	-0.4165	-0.4194	-0.4081	-0.4129
Interruptible	-0.1601	-0.1601	-0.1601	-0.1624

MINNESOTA DEPARTMENT OF PUBLIC SERVICE
AVERAGE RESIDENTIAL BILLS ANALYSIS

Company	Tariff Rate Designation	(1) Annual Customer Charge	(2) Combined Commodity and Demand Charges	(3) Commodity Margin ($/Mcf)	(4) True-Up ($/Mcf)	(5) Total Cost of Gas	(6) Average Use (Mcf)	(7) Total Annual Bill	(8) Compare at 140 Mcf/Year
						(2)+(3)+(4)		(1)+[(5)*(6)]	(1)+[(5)*140]
Peoples Total	(Average)	$72.00	$2.37	$1.12	$0.0842	$3.58	115.02	$483.35	$572.86
Viking	G S	$72.00	$2.08	$1.12	$0.1143	$3.31	116.10	$456.80	$536.01
Great Lakes	G S	$72.00	$2.38	$1.12	($0.0050)	$3.50	114.48	$472.11	$561.30
Northern	G S	$72.00	$2.66	$1.12	$0.1434	$3.92	114.48	$521.15	$621.28
Minnegasco Total	(Average)	$52.67	$2.81	$1.12	($0.2306)	$3.70	107.23	$451.56	$570.58
Midwest Viking	Residential	$49.00	$2.60	$0.96	$0.1949	$3.75	107.00	$450.77	$574.69
Minnegasco-Traditic	Residential	$60.00	$3.03	$1.12	($0.0468)	$4.10	115.00	$531.87	$634.45
Midwest Northern	Residential	$49.00	$2.79	$1.29	($0.8400)	$3.24	99.70	$372.03	$502.60
Great Plains Total	(Average)	$34.40	$2.90	$1.64	$0.0052	$4.54	105.17	$512.80	$670.26
Northern District*	Residential	$28.20	$2.82	$1.62	$0.0207	$4.46	105.90	$500.59	$652.70
Crookston	Residential	$46.80	$2.83	$1.97	($0.0040)	$4.80	110.30	$575.80	$718.24
Southern-13	Residential	$28.20	$3.04	$1.33	($0.0012)	$4.37	99.30	$462.02	$639.83
NSP	Res w/Heat	$72.00	$2.76	$1.44	($0.0208)	$4.18	108.00	$523.35	$657.09
Interstate	511	$57.00	$3.17	$0.81	($0.0068)	$3.97	115.55	$516.10	$613.25
Western**	Small Vol. Res w/Heat	$45.00	$3.48	$1.76	($0.0817)	$5.16	99.06	$555.98	$767.16
NMU	G S	$54.00	$3.35	$1.81	$0.0437	$5.20	151.48	$842.26	$782.52
MN NON-WEIGHTED AVERAGE		$54.25	$2.85	$1.34	($0.0376)	$4.15	112.03	$521.60	$635.47

Note: Individual company averages are non-weighted.

* Includes the towns of Fergus, Pelican, Vergas, Breckenridge and Wapheton

** Classification as reported by Western. Company also submitted information regarding large volume residential customers. This information is being reviewed by the Department.

Daily Deferred Delivery Variance Charges

	Volumes					Percent of Total Sales Volumes			
Company	**negative**	**punitive**	**positive**	**total**	**annual sales***	**negative**	**punitive**	**positive**	**total**
Peoples	136,344	712	8,441	145,496	19,109,335	0.7135%	0.0037%	0.0442%	0.7614%
Western	1,392		221	1,613	524,487	0.2654%	0.0000%	0.0421%	0.3075%
NMU	18,724	109	435	19,268	6,396,837	0.2927%	0.0017%	0.0068%	0.3012%
Great Plains	1,492	0	365	1,857	2,754,291	0.0542%	0.0000%	0.0133%	0.0674%
Minnegasco	***PROPRIETARY							PROPRIETARY***	
Interstate	656	0	152	808	2,083,028	0.0315%	0.0000%	0.0073%	0.0388%
NSP	0	0	0	0	61,584,342	0.0000%	0.0000%	0.0000%	0.0000%
MN Totals	**158,607**	**821**	**9,614**	**169,042**	**92,452,320**	**0.1716%**	**0.0009%**	**0.0104%**	**0.1828%**

* as reported in utilities annual automatic adjustment filing.

	Dollars				Total Costs	Percent of Total Costs Incurred			
Company	**negative**	**punitive**	**positive**	**total**	**Incurred***	**negative**	**punitive**	**positive**	**total**
Peoples	$54,537	$6,228	$8,441	$69,206	$53,760,201	0.1014%	0.0116%	0.0157%	0.1287%
Western	$557	$0	$221	$778	$1,565,329	0.0356%	0.0000%	0.0141%	0.0497%
NMU	$7,490	$954	$435	$8,879	$20,032,875	0.0374%	0.0048%	0.0022%	0.0443%
Great Plains	$597	$0	$365	$962	$9,926,995	0.0060%	0.0000%	0.0037%	0.0097%
Minnegasco	***PROPRIETARY							PROPRIETARY***	
Interstate	$262	$0	$152	$414	$6,247,031	0.0042%	0.0000%	0.0024%	0.0066%
NSP	$0	$0	$0	$0	$157,017,924	0.0000%	0.0000%	0.0000%	0.0000%
MN Totals	**$63,443**	**$7,182**	**$9,614**	**$111,078**	**$248,550,355**	0.0255%	0.0029%	0.0039%	0.0447%

* as reported in utilities annual automatic adjustment filing.

*** PROPRIETARY ***

Gas Utility Pipeline Transportation Sources
Design Day Pipeline Capacity Reservation

Docket No. G,E999/AA-95-844
Attachment 16

CAPACITY RELEASE

Northern EBB

Company	Actual Mcf	Total Revenues	Revenue Per Mcf
NSP	***Proprietary		Proprietary***
Western	223,543	$8,655	0.0387
Interstate	1,939,817	$68,185	0.0352
Minnegasco	***Proprietary		Proprietary***
NMU	2,134,837	$26,805	0.0126
Peoples	5,036,721	$55,051	0.0109
Great Plains	956,034	$4,780	0.0050
MN Total	**10,290,951**	**163,476**	**0.0162**

Viking EBB

Company	Actual Mcf	Total Revenues	Revenue Per Mcf
NSP	***Proprietary		Proprietary***
MN Total	***Proprietary		Proprietary***

Other EBB: (Please Identify)

Company	Actual Mcf	Total Revenues	Revenue Per Mcf	
Peoples	476,146	$165,520	0.3476	NBPL
Great Plains	28,662	$9,000	0.3140	Northern Border Pipeline
Minnegasco	***Proprietary			Proprietary***
NSP	***Proprietary			Proprietary***
MN Total	**6,786,776**		**0.1875**	

Pre-arranged Grandfathered

Company	Actual Mcf	Total Revenues	Revenue Per Mcf
NSP	***Proprietary		Proprietary***
MN Total	***Proprietary		Proprietary***

Other: (Please Identify)

Company	Actual Mcf	Total Revenues	Revenue Per Mcf	
NSP	***Proprietary			Proprietary***
Minnegasco	***Proprietary			Proprietary***
MN Total	***Proprietary			Proprietary***

Sum of Capacity Releases

Company	Actual Mcf	Total Revenues	Revenue Per Mcf	Total Costs Incurred*	% of Total Costs Represented by Capacity Release Total Revenues
Interstate	1,939,817	68,185	0.0352	$6,247,031	1.09%
Western	223,543	8,655	0.0387	$1,565,329	0.55%
Minnegasco	***Proprietary				Proprietary***
NSP	***Proprietary				Proprietary***
Peoples	5,512,867	220,571	0.0400	$53,760,201	0.41%
Great Plains	984,696	13,780	0.0140	$9,926,995	0.14%
NMU	2,134,837	26,805	0.0126	$20,032,875	0.13%
MN Total	**10,795,759**	**2,704,335**	**0.2505**	**$91,532,431**	**0.46%**

COMMISSION ADDED UTILITY FILING REQUIREMENTS
SEPTEMBER 1, 1994 TO AUGUST 31, 1995

GREAT PLAINS

Docket No. G004/M-94-21:
Date issued: November 4, 1994 for Crookston, MN
Required Great Plains to provide the following penalty information at the time of its next annual automatic adjustment report:

1) For each penalty imposed under its current balancing and curtailment provisions, the Company shall provide:
   - customer's name
   - customer class
   - date of the penalty
   - amount of penalty
   - method used to identify the customer's gas use on day of the imposed balancing penalty

Compliance:
2) Company shall record each type of penalty separately (both costs from pipelines and penalties revenues from its customers) for review in the next annual automatic adjustment report.

Docket No. G004/M-94-22:
Date issued: November 4, 1994 for Northern District
Required Great Plains to provide the following penalty information at the time of its next annual automatic adjustment report:

1) For each penalty imposed under its current balancing and curtailment provisions, the Company shall provide:
   - customer's name
   - customer class
   - date of the penalty
   - amount of penalty
   - method used to identify the customer's gas use on day of the imposed balancing penalty

2) Company shall record each type of penalty separately (both costs from pipelines and penalties revenues from its customers) for review in the next annual automatic adjustment report.

INTERSTATE

Docket No. G001/M-93-1219:
Date issued: September 20, 1994
Required Interstate to return all capacity release revenues to ratepayers in its annual true-up adjustment.

MINNEGASCO

Docket No. G008/M-94-853:
Date issued: January 23, 1995 For Minnegasco-Northern
Required Minnegasco to provide balancing and curtailment information at the time of its next annual automatic adjustment report.

Docket No. G008/M-93-1233:
Date issued: January 23, 1995 For Minnegasco-Northern
Required Minnegasco to provide balancing and curtailment information at the time of its next annual automatic adjustment report.

Docket No. G008/M-93-1234:
Date issued: January 23, 1995 For Minnegasco-Northern
Required Minnegasco to provide balancing and curtailment information at the time of its next annual automatic adjustment report.

Docket No. G008/GR-93-1090:
Date issued: October 24, 1994
Required Minnegasco to report on its efforts to lower its demand and commodity cost of gas following its consolidation with Midwest Gas in its next annual fuel report.

NMU

Docket No. G007/M-94-20:
Date issued: December 9, 1994
Required NMU to file an annual cost/benefit analysis of the Mobil Contract in conjunction with its annual report.
Also see "All Utilities" Docket No. G,E999/AA-94-762 below.

NSP

Docket No. G002/M-93-1149:
Date issued: November 7, 1994
Ordered NSP to provide the following penalty information at the time of its next annual automatic adjustment report:

- customer's name
- customer class
- date of the penalty
- amount of penalty
- method used to identify the customer's gas use on day of the imposed balancing penalty

Docket No. G002/AI-94-838:
Date issued: March 16, 1995
Ordered NSP to include in future Annual Automatic Adjustment of Charges reports monthly summaries of transactions between itself and NSPW and between itself and Cenergy.

Docket No. G002/M-94-103:
Date issued: March 20, 1995
Paragraph 6: NSP shall amend its 1994 true-up filing so that all of the revenue is returned during the 1994 true-up period using the estimated remaining sages volume in the denominator of the calculation of the amended 1994 true-up adjustment.

Docket No. G002/M-94-938:
Date issued: August 11, 1995
Required NSP to include a report regarding an expanded project.[1]

Docket No. G, E002/AI-94-729:
Date issued: August 16, 1995
Required NSP to report the volume of gas, gas costs, and gas revenues for service under the Agreement in the 1995 and 1996 true-up report. Also required NSP to report the value of the pipeline capacity used to serve NSP Generation, using the data for the quarterly compliance reports and after the fact cost information in the PGA true-up report.

[1] The project referred to is fully identified and described in the filing submitted to the Commission by the Company, page 3, and is discussed on pages 5-6 of the Department's December 9, 1994 proprietary comments and on pages 1 and 2 of Attachment 4 to those Comments.

PEOPLES
Docket No. G011/M-94-1082:
Date issued: August 23, 1995
Ordered Peoples to provide the following peak-period information for all of the jurisdictions in which Peoples operates that are directly connected to the Northern system at the time of the Company's next annual fuel report:

- peak-period date(s);
- peak-period duration;
- peak-period sendout by day; and
- the amount of Interruptible supplies used to meet firm, peak-period requirements;

WESTERN
Docket No. G012/AA-93-218:
Date issued: May 16, 1995
Required Western to include in its 1995 true-up all gas costs over-collected between July 1, 1994 and June 30, 1995.

Docket No. G012/M-93-1251:
Date issued: December 20, 1994
Required Western to report on all capacity-release transactions and all penalties imposed on the Company by its pipelines and all penalties imposed by the Company on its customers in the next annual automatic adjustment report.

ALL UTILITIES
Docket No. G,E999/AA-94-762
Date Issued: July 13, 1995

1. Required NMU to include a cost/benefit analysis of its gas supply contract with Mobil in its 1995 annual report. And required both NMU and Peoples to include a cost/benefit analysis of its choice of UtiliCorp as a gas supplier in their 1995 annual reports.

2. Required NSP Gas to include a report of its investigation of whether NSP was under-or overcharging NSP Generation and any provision make for refunding NSP Gas's sales customers is a refund is necessary in September 4, 1995 PGA filing. Also required a report of NSP accounting for gas sold to NSP Generation and a comparison of NSP's present inter-company accounting system with the Company's new invoicing system for transactions with NSP Generation.

3. Required the Department to provide the following:

   a. a brief analysis of the electric utilities' procurement policies, dispatching procedures, cost-minimizing efforts, and fuel-cost projections;
   b. a brief summary of the utilities' treatment of lost and unaccounted for gas;
   c. inclusion of each company's reserve margin percentage in the table containing each utilities design-day requirements;
   d. a summary of utility filing requirements that have been added by the Commission since September 1, 1994;
   e. an analysis of People's and NMU's cost/benefit quantifications of the choice of UtiliCorp as a gas supplier.

STATE OF MINNESOTA)
) ss
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, **Kathy Brengman**, being first duly sworn, deposes and says: than on the **28th** day of **February, 1996,** she served the attached **Department of Public Service Monthly Purchased Gas Adjustment Report DOCKET NUMBER:**

XX by depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid
XX by personal service
by delivery service
by express mail

to all persons at the address indicated below or on the attached list:

Kathy Brengman

Subscribed and sworn to before me

this 28th day of February, 1996

Karen L. Santori

KAREN L. SANTORI
NOTARY PUBLIC – MINNESOTA
WASHINGTON COUNTY
My Comm. Expires Jan. 31, 2000

G,E999/AA-95-844

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