PUBLIC UTILITIES COMMISSION

To: Minnesota Legislature

From: Burl W. Haar, Executive Secretary
Minnesota Public Utilities Commission (MPUC)

Date: February 3, 1999

Re: Report on Performance-based Gas Purchasing Plans, pursuant to Minn. Stat. § 216B.167, subd. 7 (1995)

Please find enclosed the MPUC's report evaluating the effectiveness of performance-based gas purchasing plans approved under Minn. Stat. § 216B.167 (1995).

This report was required pursuant to Minn. Stat. § 216B.167, subd. 7 (1995).

The performance-based gas purchasing statute expires on January 1, 2000, unless the sunset provision in Minn. Stat. § 216B.167, subd. 8 (1995) is repealed or extended in the 1999 legislative session.

Please do not hesitate to contact the MPUC's Legislative Liaison, Mike Bull, at 651.296.1337, if you have any comments, questions or suggestions regarding this report.

cc: Service List for MPUC Docket No. G-008/CI-98-1219

Report on Performance-based Gas Purchasing Plans, pursuant to Minn. Stat. § 216B.167, subd. 7 (1995)

Minnesota Public Utilities Commission
Docket No. G-008/CI-98-1219
February 1999

Dated: February 3, 1999

Statement of the Cost to Prepare this Report

Minn. Stat. § 3.197 requires that "A report to the legislature must contain, at the beginning of the report, the cost of preparing the report, including any costs incurred by another agency or another level of government."

The Minnesota Public Utilities Commission estimates that its total cost of preparing this report was $12,525. Of this total cost, $12,150 was attributable to staff costs and $375 was attributable to production costs.

The Minnesota Department of Public Service estimates that its costs were $4,800 and the Office of Attorney General-Residential Utilities Division estimates that its costs were $1650.

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I. Introduction

In 1995, the Minnesota Legislature passed Minnesota Statutes, section 216B.167, authorizing the Minnesota Public Utilities Commission to approve "performance-based gas purchasing" plans according to the criteria set out in that section. Section 216B.167 requires a performance-based gas purchasing plan to include:

- incentives for the natural gas utility to achieve lower natural gas costs than would have been achieved in the absence of the plan;

- a provision to share the potential benefits of the plan among each customer class purchasing firm natural gas service from the utility;

- one or more benchmarks against which actual natural gas costs would be measured and that the benchmarks reflect relevant market conditions and represent reasonable and achievable natural gas costs in Minnesota for the term of the plan; and

- a mechanism through which the utility shares with its customers the difference between actual natural gas costs and the plan's benchmark costs during the term of the plan.

Section 216B.167, subd. 7, also requires the Commission to "evaluate the effectiveness of all plans approved under this section and submit its findings to the legislature by January 1, 1999." This report satisfies that statutory requirement.

In its May 21, 1996 Order,[1] the Commission approved a plan proposed by Minnegasco, as modified by a settlement entered into by Minnegasco and several interested parties. The plan was in effect for three years. Minnegasco did not request that the plan be renewed, thus it ended on June 30, 1998.

The Minnegasco proposal was the only such plan presented to the Commission under the statute, and as such, serves as the basis for the Commission's evaluation of section 216B.167.

The performance-based gas purchasing statute expires on January 1, 2000, unless the sunset provision in subdivision 8 of section 216B.167 is repealed or extended in the 1999 legislative session.

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[1] ORDER APPROVING MINNEGASCO'S PERFORMANCE-BASED GAS PURCHASING PLAN AS MODIFIED BY SETTLEMENT, In the Matter of Minnegasco's Petition for a Performance-Based Gas Purchasing Plan, May 21, 1996, Docket No. G-008/M-95-465

II. Economic Regulation of Public Utilities

This section of the report briefly describes the traditional model of economic regulation and how performance-based regulation compares to that traditional model.

A. Generally

1. Traditional cost of service regulation

Under the traditional regulatory model, a regulated utility offers its services at prices or rates that are based on the cost of those services, rather than on the value customers place on the services.

The best example of traditional cost of service regulation is the contested rate case, wherein the utility's "revenue requirement" (i.e., the reasonable and prudent cost of providing regulated services plus a return on invested capital) is determined. The responsibility for funding this revenue requirement is then allocated among the utility's customer classes, and the utility's rates are "designed" to raise the revenue requirement from the various customer classes, in accordance with certain public policy and economic objectives.

Critics argue that "cost-based" regulation allows the utility and its shareholders to pass on all of the utility's costs and risks to its ratepayers. Because the utility faces minimal risks, the utility has little or no incentive to increase its operating efficiency or to minimize expenses. Cost of service regulation, it is argued by some, "fails to penalize inefficient producers or reward efficient ones."[2]

Not that the traditional system of regulation is entirely without performance incentives. Under cost-based regulation, a utility is generally authorized to charge the same rate indefinitely. Between rate cases the utility can take steps to control costs and improve efficiency to earn as high a rate of return as possible — often referred to as "regulatory lag." In a period of high growth and/or decreasing costs the Commission's recourse against utilities over-earning against their allowed rates of return is to initiate an earnings investigation and to conduct a cost of service investigation similar to what would occur in a rate case. Alternatively, if the utility believes it is under earning its allowed rate of return it may request permission to increase its rates.

2. Performance-based/incentive regulation

In general, incentive regulation is "an alternative to, or modification of, cost of service regulation, which is used in markets that lack sufficient competition (examples include price caps, zone of

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[2] Ros, Augustin J. and Harvill, Terry S. "Incentive Ratemaking in Illinois: The Transition to Competitive Markets," Public Utilities Fortnightly, July 15, 1995, p. 22.

reasonableness, bounded rates, sharing of efficiency gains, and incentive rates of return)."[3]

Performance-based regulation (PBR), such as performance-based gas purchasing plans, is one form of incentive regulation. Incentive regulation attempts "to provide or enhance incentives for utilities to achieve desired goals, such as operational efficiency or conservation targets, [4] by inserting a system of rewards and penalties into the regulatory structure and by increasing the ability of utilities to meet competitive demands."[5]

Advocates of PBR argue that the correct mix of incentives and operational flexibility will lead regulated entities to more closely mimic the actions of an efficient firm under competitive pressures, inducing the regulated entity to achieve efficiency gains that leave both customers and shareholders better off.

There are, however, several potential problems that policymakers should be aware of with regard to PBR plans. These include:

- the inclusion in the PBR of performance goals or benchmarks which are too-easily achieved by the utility
- the incorporation in the PBR of contradictory societal or regulatory goals
- the inclusion of too strict restrictions on the utility's ability to retain PBR savings, thereby minimizing the utility's incentive to operate more efficiently
- the ability of the utility under the PBR to stifle potential competition by utilizing monetary gains from improvements in its performance to cross-subsidize potentially competitive services

Policymakers should also keep in mind that PBR plans are implemented on top of the current rate structure. If the utility is over-earning under the current rate structure (rates are inflated relative to costs), a PBR plan may exacerbate, rather than cure, this problem. Policymakers implementing PBR plans should ensure that the current rates of the utility are reasonable before proceeding under a PBR plan.

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[3] The Potential for Natural Gas in the United States, Regulatory and Policy Issues, December 1992, National Petroleum Council, Glossary, p. 7

[4] The Commission is currently reviewing the existing financial incentives for demand-side management energy conservation programs for gas and electric utilities in a Chair's Roundtable, in Docket No. E,G-999/CI-98-1759.

[5] Restructuring the Electric Industry, January 1997, Minnesota House of Representatives Research Department, p. 53.

B. Performance-Based/Incentive Regulation of Public Utilities in Minnesota

1. Telecommunications

In 1995, the Minnesota Legislature gave the Commission authority to approve alternative regulation plans for telecommunications companies pursuant to Minn. Stat. §§ 237.76.[6] The purposes of an alternative regulation plan are to provide a telephone company's customers with service of a quality consistent with Commission rules at affordable rates; to facilitate the development of telecommunication alternatives for customers; and to provide, where appropriate, a regulatory environment with greater flexibility than is available under traditional rate-of-return regulation.

Several telecommunications companies in Minnesota are currently operating under such plans including Frontier, United/Sprint, U.S. West and several other smaller companies.

U.S. WEST accepted a Commission-modified Alternative Regulation Plan which became effective January 1, 1999. The U.S. West Plan calls for U.S. WEST to reduce its charges for price-regulated services by an estimated $67.9 million annually by the third year of the Plan, or by an estimated $294.5 million over five years. Significant reductions are in residential flat-rate service, business line rates, the Carrier Common Line element of switched access, and reductions in some Extended Area Service rates. The Plan also includes a three-year freeze on price increases; specific investment and new service implementation commitments; measurable service quality goals, including remedies and penalties for failure to meet the goals; and a broadened ability for the Commission to investigate and respond in cases involving competitively-sensitive issues. Benefits to U.S. WEST include added regulatory flexibility to position itself more effectively in a competitive market and the ability to address market developments immediately and more aggressively.

2. Gas

Minnesota Statute, section 216B.167 is the subject of this report. In addition, in 1997, the Minnesota Legislature passed Minnesota Statute, section 216B.1675, "performance regulation plan for gas utility services." Section 216B.1675, permits the Commission to authorize incentive plans for the non-gas part of gas utility service, i.e. the part that does not include the cost of buying and storing gas and then shipping it on interstate pipelines to the Minnesota utility's distribution system. As of January 1, 1999, no proposals for such a plan had been submitted to

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[6] Minn. Stat. §§ 237.76, et al, permit telecommunications companies an exemption from rate of return regulation and earnings investigations if they become subject to an alternative regulatory plan. In 1997, sections 237.76, et al, were amended. Unless the sunset provisions are repealed, the telecommunications AFOR statues expire on January 1, 2006.

the Commission for review under section 216B.1675.

3. Electric

At present there is nothing in the Minnesota Statutes that expressly permits the PUC to authorize an electric PBR plan.

The report, Performance-Based Regulation in a Restructured Electric Industry,[7] National Association of Regulatory Utility Commissioners, November 8, 1997, provides a current summary of electric PBR in the Untied States.

C. Economic Regulation of Gas Purchasing

This section of the report describes the mechanisms currently in place for regulatory review of gas purchasing, describes incentive mechanisms, and discusses two other alternatives that could be considered - outsourcing and unbundling.

1. Gas purchasing in Minnesota under traditional cost of service regulation

The main incentive to control costs and purchase economical or "best cost" gas supplies is the after-the-fact prudence reviews that are a part of the Commission's "purchased gas adjustment" (PGA) process. The PGA process allows local natural gas distribution companies (LDCs) to purchase the natural gas they need to serve their customers and then automatically pass the cost on to their customers on a monthly basis. These monthly cost adjustments (purchased gas adjustments or PGAs) are implemented by the local distribution companies (LDCs) on a provisional basis, subject to later review by the Commission. The after-the fact prudence review occurs at the end of each gas year when the gas companies propose annual true-up adjustments to reconcile their monthly adjustments with their actual cost of gas for the year.

Under the present PGA system, virtually all firm customers pay the same (system-wide average) demand plus commodity cost of gas and all interruptible customers pay the same (system-wide average) commodity-only cost of gas - regardless of the costs they actually impose on the system. The LDC is in a revenue neutral position with respect to how these cost are collected from its customers, unless one cost recovery method would encourage more usage than another. If one group of customers pays less - then another group of customers will have to pay more.

2. Suspension of the energy cost adjustment

Perhaps the simplest incentive to implement would be the suspension of a gas company's authority to automatically adjust its rates to recover its cost of gas. Setting the gas cost recovery

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[7] This report is available on the Internet at: www.naruc.org/Publications

charge at a fixed rate without allowing a later reconciliation to actual costs would put the company at risk if gas costs rise above the fixed rate and would put ratepayers at risk if gas costs fall below the fixed rate. While this alternative would remove the safety net of the PGA, it would also allow companies to earn a profit or suffer a loss on the gas they sell in addition to the rate of return they earn on the non-gas part of each customer's bill.

To date, only one gas company has had its authority to automatically adjust rates suspended. In that instance, the over-recovered gas costs were returned when the suspension was lifted.

It should be noted that in 1995, the Commission initiated an investigation into whether there was a still a need for the automatic adjustment mechanism for gas utilities and found that the PGA served a useful purpose. In its investigation the Commission found that natural gas prices are the most volatile of all commodity prices.[8]

3. Gas purchasing incentive mechanisms

Gas purchasing incentive mechanisms, such as those included in Minnegasco's PBR plan, attempt to address the difficulty of conducting useful after-the-fact prudence reviews and to create an incentive for utilities to achieve lower gas prices for their customers than would have been realized under a straight, automatic pass through of reasonable gas costs.

Another purpose of most gas purchasing incentives is to try to make regulated gas prices emulate the results (i.e. the prices, etc.) that would be found in a competitive market for natural gas.

The two key parts of Minnegasco's gas purchasing incentive mechanism approved under Minn. Stat. § 216B.167 were the benchmarks and the sharing mechanism.

a. Benchmarks

In general, benchmarks can be thought of in two ways.

Benchmarks can be designed so that they are goals (or targets) that the utility should reasonably be able to meet. This type of benchmark could be used to determine prudence. Costs in excess of the benchmark would be disallowed or if the benchmark is a price cap, costs in excess of the price cap would not be subject to later recovery by the utility.

Alternatively, benchmarks can be designed so that only the highest performance level can attain the goals established by the benchmark(s).

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[8] ORDER CONCLUDING INVESTIGATION AND CLOSING DOCKET, In the Matter of an Investigation into Whether the Purchased Gas Adjustment (PGA) is Still Appropriate, November 18, 1996, Docket No. G-999/CI-95-696

The establishment of a benchmark of any kind creates a competitive situation in which a utility is competing with itself to perform at the level established by the benchmark. Competition amongst LDCs can be increased by setting the benchmark to a competing LDC's performance level rather than to an external, market-based or historical index. Requiring a utility to compete against a "moving" target, rather than a "fixed" target, makes it more challenging for a utility (or a regulator) to manipulate or lock in the outcome of an incentive plan (i.e., to maximize a reward or minimize a penalty). A moving target would be one that changes monthly as gas prices change in the market. A fixed target would not change during the course of a plan.

b. Sharing mechanism

Sharing mechanisms predetermine how monetary gains and losses derived under a PBR plan would be shared between the utility's ratepayers and its shareholders. If the benchmarks are set at levels the utility should normally be able to attain without an incentive, then the sharing mechanism should be structured to encourage higher performance and to penalize poor or indifferent performance. In many respects, there is a trade-off between how the benchmarks are set and the design of the sharing arrangements. The more attainable the benchmarks are for the LDC, the more aggressively designed in favor of the ratepayer the sharing arrangement needs to be in order to maintain overall equity between the Company, (e.g. its employees, management and shareholders) and its ratepayers.

4. Outsourcing of the LDC gas purchasing and supply function

In theory, outsourcing might seem like a logical idea, yet in practice, the details are quite formidable. In proceedings involving the review of the 1997 Annual Automatic Adjustment Reports,[9] the Minnesota Department of Public Service (the Department) and the Minnesota Office of Attorney General-Residential Utilities Division (OAG) raised interesting points with respect to outsourcing. In the briefing papers submitted in the 97-1212 docket to the Commission by its staff, outsourcing was discussed as follows:

> Staff believes that based on the activity in Minnesota and elsewhere, outsourcing of an LDC's gas procurement function through a competitive bidding process is increasingly becoming a "best cost" alternative for some LDCs and their ratepayers. This is not by any means a one-size fits all solution for each and every LDC. However, with the increasing sophistication of the marketing community and an evolving gas market, reliable bids for whole system supply requirements should become more readily available. This will encourage more competition amongst competing suppliers as well as allowing for useful price discovery.

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[9] In the Matter of the Review of the 1997 Annual Automatic Adjustment of Charges for All Gas and Electric Utilities, Docket No. G,E-999/AA-97-1212

5. Unbundling[10]

Unbundling is the process of separating out the package of services offered by a local distribution company --, i.e. gas supply, gas storage, distribution, metering, billing, etc. -- and charging separate rates or rate components for each service that fairly represents the cost of providing that service.

Natural gas unbundling has been under review in Minnesota in a stakeholder work group since 1997. A Commission staff report on the natural gas unbundling stakeholder work group was accepted by the Commission in August 1998. The MPUC requested a state-wide unbundling implementation plan from the work group by August 1999.

Prior to the formation of the work group, the Commission considered and dismissed a request for a pilot program from Minnegasco[11] and a request for rulemaking from Enron, et al.[12] It is the Commission's understanding that currently, there are no gas utilities in Minnesota interested in further unbundling of service on their systems prior to the restructuring of electric service.

III. Minnegasco's Performance-based Gas Purchasing Plan

A. Overview

On August 7, 1995, Minnegasco filed its petition for approval of a performance-based gas purchasing plan (plan), pursuant to Minn. Stat. § 216B.167 (1995).[13] Minnegasco's plan is the only gas purchasing incentive plan submitted under this statute in Minnesota.

According to statute, these plans must include reasonably attainable benchmarks, a sharing mechanism and a proposal for how the plans will be evaluated. This plan was proposed as a three-year pilot that ended on June 30, 1998.

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[10] For further information about natural gas unbundling see Energy Deregulation, Status of Natural Gas Customer Choice Programs, Report to Congressional Requesters, United States General Accounting Office, December 1998, Report No. GAO/RCED-99-30 (www.gao.gov/reports.htm)

[11] In the Matter of Minnegasco's Petition for Approval of a Miscellaneous Rate Change to Revise its Tariffs in Response to Industry Changes Brought About by FERC Order 636, Docket No. G-008/M-95-216

[12] In the Matter of a Petition to Establish Rules and Regulations for Natural Gas Consumer Choice, Docket No. G-999/R-97-1317

[13] In the Matter of Minnegasco's Petition for a Performance-Based Gas Purchasing Plan, Docket No. G-008/M-95-465

The Department and OAG commented on Minnegasco's plan. Settlement discussions and a formal agreement followed. Minnegasco's plan as modified by the settlement was approved by the MPUC in an order dated May 21, 1996.

The Commission must evaluate the effectiveness of all plans approved under this section of the statute, and submit its findings to the Legislature by January 1, 1999, pursuant to Minn. Stat. § 216B.167, subd. 7 (1995).

1. Benchmarks

Minnegasco's plan allowed Minnegasco to earn a reward for achieving actual gas costs that are lower than the predetermined benchmarks. Minnegasco also risked paying a penalty if its gas costs are higher than the benchmark.

Minnegasco's plan contained a two-part benchmark. Each part carried equal weight and counted for 50% of the total.

The first part of the benchmark was called the LDC Benchmark (PBR Model 1). The LDC component of the benchmark was the volume weighted average cost of gas for the three largest LDCs in Minnesota other than Minnegasco.

The second part of the benchmark was called the "Market-Based" Benchmark (PBR Model 2) and consisted of two components, the commodity cost component and the demand cost component. The commodity component was based on a commodity price reference point, i.e. the bid week price[14] for gas on Northern Natural delivered to the Ventura, Iowa interconnection point. The demand component of the benchmark was based on the amount of pipeline capacity Minnegasco had under contract in the base-year.

2. Sharing mechanism

The plan contained a sharing mechanism as required by statute. The sharing mechanism included a dead-band (within which no sharing takes place), a 50/50 sharing of rewards and penalties outside the dead-band, and a dollar limit on the amount of the reward (or penalty) that could be earned (or charged) in a single year under the plan.

3. Implementation, Annual Report & True-up

Any reward or penalty determined under the plan was implemented at the same time as

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[14] In the last week of each month, gas utilities (and other gas buyers) request and then accept bids for the gas they expect to buy and then sell to their customers in the following month. The bid week price is the price that results from this bidding process.

Minnegasco's annual gas cost reconciliation adjustment (true-up).[15] (Minn. Stat. § 216B.16, subd. 7a (1995)) Minnegasco delayed the implementation of its gas cost true-up for two months until (Nov. 1) of each year to calculate the PBR numbers correctly.

Minnegasco's plan applied to all sales (i.e. system) customers which included all of Minnegasco's firm and interruptible sales customers. The plan did not apply to Minnegasco's transportation (i.e. distribution only) customers.

4. Evaluation

Minnegasco's plan and the settlement contained reporting and information gathering requirements that were intended to allow parties to form opinions on whether the statute and Minnegasco's plan have helped lower gas costs below the level they would have been absent the plan and without any reduction in service quality.

B. Performance Benchmarks in Minnegasco's Plan

1. LDC Benchmark (PBR Model 1)

a. Proposed Benchmark

Minnegasco proposed that this benchmark be based on the costs of similarly situated utilities. The theory being that having Minnegasco compete with the three other largest Minnesota local distribution companies (LDCs) for incentives would lower gas costs for all Minnesota customers. In some years Minnegasco would win, and in other years Minnegasco would lose. This would emulate the competitive marketplace.

The Company proposed to compare its actual annual cost of gas per MMBtu[16] for the applicable gas year under the Plan with the volume weighted average for NSP, Peoples, and NMU. The calculation is each company's total gas cost (commodity and demand) divided by total sales. Minnegasco stated that NSP, Peoples, and NMU are a reasonable proxy for relevant market conditions in Minnesota for the cost of natural gas.

The following table compares Minnegasco's average cost of gas with what the benchmark would have been for fiscal years ended June 30, 1992 through 1995, and what the benchmark was for fiscal years 1996 through 1998. At the time Minnegasco filed its proposal only the information

[15] Each year on September 1, gas utilities submit a gas cost true-up filing which compares the companies' actual gas costs with the gas costs that were collected from customers in rates. The difference is then collected or refunded over the following twelve months.

[16] MMBtu is one million Btus which is equal to a dekatherm. An Mcf, which is a unit of volume, is approximately equal to a MMBtu.

for 1992 - 1994 was available.

	Volume weighted average of 3 LDCs (in $/MMBtu)	Minnegasco (in $/MMBtu)	Percent difference from average
FY 1992	$2.7668	$2.6666	-3.62%
FY 1993	$3.2599	$3.1833	-2.35%
FY 1994	$3.1329	$3.1656	1.03%
FY 1995	$2.6548	$2.7140	2.23%
FY 1996	$2.6943	$2.7814	3.23%
FY 1997	$3.4603	$3.5493	2.57%
FY 1998	$3.2937	$3.2993	0.17%

Minnegasco and the Department worked together to develop the benchmarks. The Department stated that this comparison was objective because each of the companies independently decide how to best purchase gas and it is reasonable because they face similar weather and market conditions. According to the Department, the comparison promotes competition amongst Minnesota gas utilities by rewarding or penalizing Minnegasco based on its performance relative to the other LDCs. The Department believes that such competition promotes the public interest, since Minnegasco will have an incentive to lower its gas costs.

b. Concerns About Proposal

The OAG expressed concerns as to whether this benchmark met the statutory requirement that the benchmark be a fair measurement of what Minnegasco's gas costs would have been absent the Plan. The OAG stated that while Minnegasco's petition claimed that the three LDCs' weighted average cost of gas represented a good proxy for Minnegasco's own cost of gas, the comparison was limited to three years (1992 - 1994). The OAG's analysis indicated that if the plan had been in effect for those three years, this LDC benchmark component would have identified $19.5 million of savings for Minnegasco. The concern was that historically Minnegasco's gas costs were lower than the proposed benchmark. Therefore, the benchmark as proposed, would allow Minnegasco to earn an incentive simply by continuing its existing purchasing practices and would not meet the criteria to achieve lower natural gas costs than would have been achieved in the absence of the plan.

The OAG believed it was noteworthy that the historical average cost differentials between Minnegasco and the LDC benchmark were experienced in the absence of any incentive plan. Thus the LDC component is biased in Minnegasco's favor and does not accurately predict the cost of gas Minnegasco would experience in the absence of the plan.

The OAG also expressed concern about situations such as what if Minnegasco's cost of gas did not change but the other LDCs experienced cost increases beyond their control. If that were to occur, this benchmark component would credit Minnegasco shareholders with 50 percent of the increase experienced by other LDCs. This would create a windfall for Minnegasco even though it did not decrease its cost of gas.

It would be difficult, if not impossible, to determine whether cost differentials between Minnegasco and the other gas utilities were due to more effective cost savings efforts by Minnegasco than by other LDCs, or whether they were due to uncontrollable factors. The OAG argued that a review of the figures (for 1992 - 1994) in the Table above indicates that the cost differentials between Minnegasco and the LDCs were far larger in magnitude than any other benchmark component, that they were frequent, and that they tended to favor Minnegasco even in the absence of an incentive plan.

Taken together, these factors suggested that this benchmark component may be much more likely to create large and unwarranted transfers of money from Minnegasco customers to Minnegasco shareholders than the other benchmark components. The OAG suggested that the bias in the projection of future gas costs could be reduced by subtracting the average cost differential experienced in the previous three years from the benchmark. Minnegasco's larger size and geographical advantage may be accounted for by subtracting an annual productivity factor from the LDC benchmark. Finally, the problem of windfall transfers from Minnegasco customers to Minnegasco shareholders when other LDCs experience cost increases that Minnegasco is isolated from, can be prevented by having this component of the benchmark set equal to zero whenever the cost of the other LDCs exceeds that of Minnegasco. According to the OAG, together, these three modifications would make the LDC component an effective, fair and efficiency-enhancing part of the plan's benchmark.

c. Response to Concerns

Minnegasco disagreed with the OAG's conclusions, stating that this comparison demonstrates that its total annual gas cost per MMBtu was very similar to the volume weighted average of the other three Minnesota LDCs' for the three years ending June 30, 1994. Minnegasco provided revised results of the savings from the LDC benchmark for 1992 - 1994 using actual sales for the period. Rather than the $19.5 million in savings, the Company's schedule showed the savings would have been $16.2 million. The Company noted that these amounts do not take into account the effects of the other benchmark or the deadband which would have reduced any amounts shared. In fact in 1994, the most recent year, Minnegasco would have had a gross penalty of nearly $4 million.

Minnegasco contended that the LDC Component should be reviewed in the context of the entire benchmark. It would be an inappropriate and piecemeal analysis to focus on only one component of the benchmark to make a judgement on the reasonableness of the plan. Instead, the annual historical results should be considered to determine the reasonableness of the Plan's proposed portfolio approach to establishing the gas cost benchmark. The actual incentive reward/(penalty) which would have been earned by Minnegasco would have been $1.4 million (1992), $1.2 million (1993), and ($258,000) (1994). This trend indicated a very competitive situation for Minnegasco.

Minnegasco opposed the OAG's three proposed modifications, stating it would never have the opportunity to be rewarded under the OAG's recommendations, only penalized. It is impossible to design absolute precision into an experimental pilot program. There is no "one correct method" required by law or reason to be used in developing this PBR plan. The Plan is objectively reasonable and should be approved as filed.

The Department also disputed the OAG's conclusions. The Department stated this benchmark offered several advantages. It probably best reflects the competitive pressures most unregulated businesses face. Factors influencing gas costs that are not captured by published indices would likely have similar effects on utilities operating in the same region. Using three benchmarks -- published indices, Minnegasco's historical costs, and the gas costs of other LDCs -- reduces the risk of implementing a new regulatory approach by mitigating the impact of any one benchmark.

For the Department, the issue then became whether the benchmark needed to be revised to reflect any advantages Minnegasco may have over other utilities. The Department stated that NSP and UtiliCorp (i.e. Peoples and NMU) can exploit many of the same gas purchasing strategies as Minnegasco.

The Department stated that it understood the reasoning behind the OAG's proposed adjustment to the benchmark based on cost differences during a historical period. But any such adjustment should probably be weighted in favor of recent experience, as the industry has changed significantly during the last few years. In the most recent historical year, Minnegasco's costs were about 1.0 percent higher than the LDC average.

UtiliCorp also filed comments supporting Minnegasco's proposal. UtiliCorp stated that the OAG's proposal to change this benchmark should be rejected. Clearly the statute was intended to allow an LDC to receive an incentive payment for superior performance. UtiliCorp argued that Minnegasco's historical performance has been better than the proposed benchmark, therefore, Minnegasco should receive an incentive payment for maintaining past levels of success.

d. Settlement

Minnegasco, the Department of Public Service and the Office of Attorney General-Residential Utilities Division submitted a settlement agreement to the Minnesota Public Utilities Commission to resolve the conflicting positions. The parties agreed to accept Minnegasco's proposal with the addition of a limit on the impact of the LDC Component to 1.5 percent, either positive or negative, of Minnegasco's total annual gas costs. In other words, the reward or penalty from this benchmark component would be either the actual reward or penalty or 1.5% of

Minnegasco's total annual gas cost for the year, whichever was less.

This resolution of the design of the Model 1 - LDC Benchmark was based on the following rationale: "this 1.5% limitation addresses the OAG's concern about a potentially large consequence to Minnegasco resulting from the other LDCs' gas costs. In addition, this LDC Component limitation completely eliminates the historical differential that was previously shown in the OAG's comments."

In briefing materials submitted to the Commission, its Staff noted that it was not accurate to state that the LDC Component limitation completely eliminates the historical differential that was previously shown in the OAG's analysis, as corrected. The gross LDC benchmark reward calculated in the table is $16.2 million. The 1.5 percent of gas cost limitation reduced that amount to $6.1 million. It did not eliminate the disparity, it simply limited the upper level of the potential reward or penalty. If the LDC benchmark component was the only benchmark in the Plan, the net reward for the three historical years would have been $2.3 million. That is the amount Minnegasco would have received after reductions for the 1.5 percent limitation, the deadband, and the 50 percent sharing. As the OAG noted, that would have happened in the absence of any incentive plan.

In evaluating a benchmark it is important to take into account the historical relationship between the benchmark and the Company's past performance. To the extent that the Company's past performance has exceeded the benchmark, an adjustment factor should be included to eliminate that difference. For the LDC benchmark in Minnegasco's plan, because the historical difference was both positive and negative, there was no clear indication that an adjustment was needed.

2. "Market-Based" Benchmarks (PBR Model 2)

a. Commodity Component

The commodity component of the benchmark was based on the bid week price for gas delivered on Northern Natural at Ventura, Iowa as reported and published in <u>Inside FERC</u> (the Ventura Index). The Ventura index price was then adjusted to add the cost of fuel and transportation on Northern Natural's pipeline system and for lost and unaccounted for gas on Minnegasco's distribution system.

Initially, the OAG objected to Minnegasco's proposal to price gas removed from storage at the market price on the date of removal rather than the actual cost of the gas.

In the settlement agreement submitted to the MPUC by Minnegasco, the Department and the OAG, "the parties agreed to maintain the commodity component of the benchmark as originally proposed by Minnegasco."

This resolution of the design of the commodity component of the Model 2 benchmark was based on the following rationale: "all parties recognized that, while storage takes advantage of seasonal price differences, these price differences do not necessarily translate into dollar-for-dollar savings in commodity costs. Further, in addition to any direct reductions in commodity costs, storage can help avoid other capacity related costs. All parties recognized that quantifying any actual or expected commodity savings due to storage and differentiating them from capacity and other costs avoided by storage would require additional time and resources. In recognition of the need for timely resolution of outstanding issues in this plan, and considering the significant modifications and improvements to the overall plan reflected in other settled items, the parties agreed to utilize the Ventura index as originally proposed by Minnegasco. Not only will this component of the benchmark be effective in the overall context of the modified plan, but the additional insights gained through the operation of the plan will help clarify the benefits and costs offered by alternative methods of accounting for gas costs such as those originally proposed by the OAG."

b. Demand Component

The demand component of the Model 2 benchmark was based on the amount of pipeline capacity Minnegasco had under contract in the base year multiplied by Minnegasco's current cost for that pipeline capacity and divided by Minnegasco's actual number of firm sales customers multiplied by the average amount of gas used in the base year by a firm sales customer.

In the settlement submitted to the MPUC, four safeguards were made part of the design of the demand component of the Model 2 benchmark. These safeguards were added to control against the possibility of the plan creating an unintended incentive or windfall profits for the utility. For example, the capacity planning criteria safeguard limits the extent to which Minnegasco can be rewarded for reducing its reserve margin beyond appropriate and/or prudent amounts.

The following is a brief explanation of the four demand-related safeguards included in the settlement:

i. Capacity Release Revenue

Settlement Resolution: "The parties agreed to include an additional $500,000 of historical capacity release revenue in the Demand Component of the Benchmark. This would increase the capacity release revenue credit in the Plan to $2,172,636 annually. Further, the parties agreed to limit the potential amount of annual capacity release revenues to be recognized as an incremental credit to Minnegasco's gas costs under the Plan to 1.5% of Minnegasco's total annual gas costs for each year of the plan."

Rationale: According to the settlement "[t]he additional $500,000 represents capacity release revenue historically derived for Minnegasco transactions involving capacity entitlements on Northern Natural ...." The parties agreed this amount would be reasonable for calculating a benchmark based on Minnegasco's historical capacity release activity. The parties also agreed that a cap (or safeguard) would be reasonable to limit the amount of capacity release revenue that can be used to reduce Minnegasco's actual cost of gas to 1.5% of its total cost of gas.

The 1.5% cap would only be for the purpose of calculating Minnegasco's performance under the plan and is not intended to discourage Minnegasco from realizing additional revenue for the benefit of its regulated customers.

(The 1.5% cap was equal to approximately $6.75 to $8.25 million depending on whether Minnegasco's total cost of gas during the plan year was closer to $450 or $550 million.)

ii. Capacity Planning Criteria

Settlement Resolution: The parties agreed to limit the potential impact under the Plan produced by changes in Minnegasco's capacity reserve margin to 1.0% of Minnegasco's total annual gas costs.

Rationale: The 1.0% cap, approximately $4.5 - $5.5 million depending on Minnegasco's total cost of gas during the plan year, for the decrease in actual demand costs attributable to changes in the Company's capacity reserve margin ensures that this factor alone cannot have a disproportionately large impact on whether Minnegasco earns a reward or a penalty under the plan. The 1.0% cap did not limit Minnegasco's ability to make reserve margin changes for appropriate reasons, however, the changes made that had an impact in excess of 1.0% of gas costs will not be recognized for purposes of the plan.

iii. Normalized Sales

Settlement Resolution: "The parties agreed that both the demand component of the benchmark and the Company's performance relative to this benchmark will compare demand costs using the base year weather normalized firm sales per customer. The base year weather normalized firm sales per customer will be 161.4 dekatherms per year, as proposed in Minnegasco's last rate case, Docket No. G-0008/GR-95-700. The Parties agreed that use of Minnegasco's proposed normalized usage data for this Plan does not constitute precedent or agreement regarding the appropriateness of using such data in any other proceeding. The Parties further agree that the annual measure of performance relative to the Benchmark will be adjusted for growth in the number of actual firm customers."

Rationale: The parties believe that "using the same baseline usage per customer in both the benchmark and the assessment of performance, and by adjusting the baseline for customer growth in the assessment of performance, rewards under the plan should accrue only where increased efficiency in the use of capacity per customer takes place relative to existing trends. This result will be further enhanced by the capacity release and the capacity planning criteria settlement provisions described below." ("This modification .... better ensures that current trends in customer growth and overall demand volumes are reflected in the benchmark.")

iv. New Peaking Facilities

Settlement Resolution: The parties agreed to include the cost of any new peaking facilities that are recovered in Minnegasco's base rates during the term of the Plan as a cost of gas (only for the purposes of the Plan). Such facility costs include all capital costs, depreciation, income taxes, property taxes, and operating or maintenance costs, which are actually recovered in Minnegasco's base rates during the term of the plan.

The Settlement also states that "this agreement regarding treatment under the Plan shall have no impact on whether such facility costs should be recovered in Minnegasco's base rates." (Propane costs were not included in facility costs because propane expenses are treated as a demand component of gas costs in the PGA.)

Rationale: "This resolution eliminates any potential that Minnegasco would be encouraged to build otherwise uneconomic peaking facilities solely to receive benefits under the Plan. Under the proposed resolution, the cost of the new peaking facilities would be accorded the same treatment under the Plan as Minnegasco's other gas costs. This change would allow the construction of any new facilities to be considered on a plan-neutral basis."

C. Sharing Mechanism in Minnegasco's Plan

Settlement Resolution: The parties agreed to modify the sharing mechanism so that Minnegasco and its customers would share 50 percent of *all savings or costs* calculated between the deadband (0.5 percent on either side of the benchmark) and the overall two percent cap (2 percent of Minnegasco's total annual gas costs).

The settlement's resolution of the design of the sharing mechanism resulted in a symmetrical sharing between the Company and ratepayers of penalties and rewards within the sharing zone. However, no sharing would occur within the deadband or outside the sharing zone. This design protected Minnegasco and its ratepayers from having to pay for only modest improvements or differences in gas costs or for savings and cost differences that can not be distinguished from imprecision in the design of the benchmarks. The cap on sharing protects the Company and ratepayers from extremely unusual outcomes that were unforseen in the original design of the PBR plan.

IV. Results

According to the results of Minnegasco's plan, the total savings by year were: $4,347,528 (in 1995-96), $10,580,605 (in 1996-97), and $12,985,733 (in 1997-98).

Of the total savings, Minnegasco kept $1,102,734 (in 1995-96), $3,980,205 (in 1996-97) and $5,395,761 (in 1997-98).

Ratepayers received $3,244,794 (in 1995-96), $6,600,400 (in 1996-97) and $7,589,972 (in 1997-98). Ratepayers received these savings as rate adjustments in the monthly PGAs.

The following table summarizes the total incentive earned by Minnegasco under the PBR Plan:

Summary Totals	Plan Year 1 July 1995 - June 1996	Plan Year 2 July 1996 - June 1997	Plan Year 3 July 1997 - June 1998
Model 1 - (Penalty)	($6,022,890)	($7,785,878)	($730,059)
Model 2 - Reward	$14,717,945	$28,947,088	$26,701,525
Average of Models 1 & 2	$4,347,528	$10,580,605	$12,985,733
Deadband	$2,005,241	$2,620,195	$2,194,212
Total Incentive (Subject to sharing)	$2,342,287	$7,960,410	$10,791,522
Incentive to Minnegasco	$1,171,143	$3,980,205	$5,395,761
Proration of 1st Year Incentive to Minnegasco	$1,102,734	n/a	n/a

The following table presents the year-by-year results for the LDC Benchmark (PBR Model 1):

Model 1 - LDC Benchmark	Plan Year 1 July 1995 - June 1996	Plan Year 2 July 1996 - June 1997	Plan Year 3 July 1997 - June 1998
Average Cost of Gas: Northern Minn. Utilities Northern States Power Peoples Natural Gas	 $2.7694 $2.6242 $2.8951	 $3.4075 $3.3852 $3.7116	 $3.4588 $3.2374 $3.4157
Model 1 - LDC Benchmark - Weighted Average Cost of Gas	$2.6943	$3.4603	$3.2937
Minnegasco	$2.7814	$3.5493	$3.2993
Excess (over) benchmark	($0.0871)	($0.0890)	($0.0056)
Penalty (without cap)	($12,571,881)	($13,015,480)	($730,059)
Lower of Penalty or the Cap on Penalty (Cap = 1.5% of Minnegasco's cost of gas)	**($6,022,890)**	**($7,785,878)**	**($730,059)**

The following table presents the year-by-year results for the "Market-Based" Benchmark (PBR Model 2):

Model 2 - Commodity/Demand Benchmark	Plan Year 1 July 1995 - June 1996	Plan Year 2 July 1996 - June 1997	Plan Year 3 July 1997 - June 1998
Minnegasco's Commodity Cost	$1.8682	$2.7032	$2.3972
Commodity Benchmark	$1.9001	$2.7975	$2.4627
Amount under Benchmark	$0.0319	$0.0943	$0.0655
Reward: Commodity	**$4,605,130**	**$13,790,559**	**$8,539,083**
Minnegasco's Demand Cost	$1.3130	$1.2066	$1.1230
Demand Benchmark	$1.4137	$1.3543	$1.2963
Amount under Benchmark	$0.1007	$0.1477	$0.1733
Reward: Demand	**$10,112,815**	**$15,156,529**	**$18,162,442**
Total Reward: Commodity/ Demand	**$14,717,945**	**$28,947,088**	**$26,701,525**

V. Comment/Analysis

A. LDC Benchmark (PBR Model 1)

Minnegasco's gas costs were higher than the LDC Benchmark in each year of the Plan resulting in a penalty each year. The per unit differential between Minnegasco's gas costs and those of the other LDCs significantly improved in the third year compared to the first two years (see table above under Results). Minnegasco attributed the improvement to the incentives provided by the Plan, including the existence of penalties for under-performing. To achieve that result, the Company revised its mix of gas supply purchases and interstate pipeline capacity, negotiated discounts from suppliers and dedicated additional resources to identify opportunities to lower gas costs.

As a result of its review and evaluation of the plan results, the OAG questioned whether the Plan delivered ratepayer benefits or company windfalls. Because Minnegasco under-performed the average of the other LDCs during all three years of the Plan, the other LDCs customers (on average) received lower gas costs without providing their gas utility with a $10.5 million incentive to perform. This was significant because Minnegasco was the only gas utility under a PBR plan but was unable to out-perform the average of the other LDCs in Minnesota which are not under incentive plans.

Minnegasco under-performed the average of the other three LDCs by $26.3 million for all three years of the Plan. However, the penalties related to the LDC benchmark were reduced to $14.5 million due to the cap. The OAG stated that one concern that led it to support the cap was that Minnegasco would benefit from poor performance of other utilities. It appears that this may have occurred in the last year of the Plan, with a significant increase in one of the three companies, and suggests why Minnegasco was able to narrow the gap.

According to the OAG's analysis, if Minnegasco's customers had paid the average of the three LDCs' gas costs, they would have saved $22 (residential), $119 (commercial), and $981 (industrial) for all three years of the Plan not including the cost of the incentive.[17]

The 1.5% cap on the LDC benchmark was intended to prevent a large windfall to Minnegasco which the OAG believed would result from this benchmark. The actual result was just the opposite. In fiscal years 1992 and 1993, Minnegasco's per unit gas cost was lower than the weighted average of the three other LDCs. However, as the table on page 11 shows that changed starting in fiscal 1994.

Because Minnegasco's cost of gas was higher than the weighted average of the three other LDCs, the Company earned a penalty for this benchmark in each of the three years of the plan. The penalty was higher than the cap in 1996 and 1997. The effect of the cap was to reduce the amount of penalty that reduced the reward from the other (Model 2) benchmark. If the cap had not been included as part of the benchmark, Minnegasco would have earned $2.4 million less incentive in the first two years of the plan. Because the actual penalty in the third year was less than the cap, the third year reward was not affected by the cap.

It is puzzling that Minnegasco's performance compared to the Model 1 benchmark was comparatively weak, given conventional economic theory that suggests the appearance of economies of scale due to larger (rather than a smaller) purchases of gas and considering the large volume of gas purchased by Minnegasco.

The joint report from Minnegasco and the Department does not include an analysis of why Minnegasco was unable to out-perform the LDC benchmark. The OAG's comments raise the question: Does the fact that Minnegasco was not able to out-perform the LDC benchmark mean that customers did not realize any gas cost savings even though Minnegasco out-performed the commodity/demand benchmark?

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[17] If Minnegasco's customers had been able to buy their gas at the Model I benchmark price, rather than at Minnegasco's PGA rate plus the incentive or reward, then Minnegasco's customers would have saved, on average $31, $168 and $1,391 over the past three years.

B. Commodity and Demand Benchmark (PBR Model 2)

The Model 2 benchmark was divided into two parts. The first part was a benchmark for Minnegasco's commodity costs and the second (more complicated) part was a benchmark for Minnegasco's pipeline transportation costs.

1. Commodity Benchmark

The commodity cost of gas performance benchmark used in Minnegasco's plan was based on the bid week price for gas received by Minnegasco on the Northern Natural interstate pipeline at the Ventura, Iowa delivery point as reported in the industry trade publication, Inside FERC (the Ventura index). The Ventura index price was then adjusted to add the cost of fuel and transportation on Northern Natural's pipeline system and for lost and unaccounted for gas on Minnegasco's distribution system.

At the time the plan was adopted, a significant amount of the gas that Minnegasco purchased was purchased under contracts with price terms that used the Inside FERC-Ventura Index as a reference price. It has been common practice in the gas industry for the price of gas purchased under long- and short-term contracts to adjust monthly, based on one of the reference (or index) prices found in industry trade publications or on NYMEX futures prices. It should be noted that the index price or NYMEX futures price is often adjusted by a "basis differential" to reflect the geographical difference between the location of the index price reference point and the location of the point where the LDC takes delivery of the gas from the its supplier.

Minnegasco's objective under the plan, was to have an average commodity cost of gas that was less than the commodity benchmark. In the initial review of Minnegasco's plan before it was implemented, the OAG recommended that the commodity benchmark equal the Inside FERC - Ventura Index minus 2.4%. Minnegasco and the Department argued that the benchmark needed to be higher than the Ventura Index because of the additional cost to transport gas to Minnegasco's distribution system from the pipeline receipt point, the cost of fuel to transport that gas, lost and unaccounted for gas on Minnegasco's distribution system and the surcharge on pipeline rates that funds the Gas Research Institute. In the settlement offer, Minnegasco, the Department and the OAG agreed on Minnegasco's proposal as filed.

As shown in the results section of this report, Minnegasco was consistently able to outperform this benchmark by fairly large total dollar amounts. $4.6 million in the first year, $13.8 million in the second, and $8.5 million in the third. If the index had been adjusted by 2.4%, these amounts would have been $1.8 million, $4.1 million, and $.9 million.

According to the OAG, Minnegasco's consistent ability to beat the commodity component of the Model 2 benchmark while at the same time not being able to outperform the other LDCs suggests that in retrospect, this benchmark may not have been as relevant to Minnegasco's actual costs as was originally thought and that in the future other benchmarks should be analyzed.

OAG indicated that in the year's preceding the base year of the plan there was a strong statistical correlation between the Model 2 commodity benchmark and Minnegasco's commodity cost of gas. However, no quantitative analysis was provided that addressed whether this statistical correlation was maintained during the three years of the plan.

If a strong statistical correlation is used as the basis for choosing a price index for a benchmark in a future plan, parties may want to consider including in such a plan, a check each year to see if the correlation has been maintained. If a certain level of correlation has not been maintained, then a revision or a correction to the benchmark might be indicated to maintain the relevance of the benchmark.

OAG also noted that during the plan, Minnegasco was able to lower its commodity costs below the Ventura Index. OAG believes that other LDCs, e.g. the LDCs included in the Model 1 benchmark, were able to outperform the Ventura Index without an incentive. OAG believes an ex-poste analysis of the relevance of this benchmark to accurately determine the effectiveness of the incentive it created would have been useful because it remains unclear why Minnegasco can not match the lower costs of its potential rivals.

2. Demand Benchmark

The demand cost of gas component of the Model 2 benchmark used in Minnegasco's plan was based on the amount of pipeline capacity Minnegasco had under contract in the base year multiplied by Minnegasco's current cost for that pipeline capacity and divided by Minnegasco's actual number of firm sales customers multiplied by the average amount of gas used in the base year by a firm sales customer. In the settlement offer approved by the MPUC, four safeguards were added to the design of the demand component of the Model 2 benchmark.

According to Minnegasco and the Department, due to the incentives provided by the Plan, Minnegasco was able to reduce its demand costs by an average of approximately $14.5 million per year during the three years of the plan.

Minnegasco and the Department attribute the demand-related savings to:

a. improvements in Minnegasco's system load factor that take advantage of the difference between Northern Natural's twelve-month base and variable rates ($1.6 million over three years).

b. more intensive monitoring, coordination and management of the daily gas supply planning function performed by Minnegasco's Throughput Management and Gas Supply staff. This enabled Minnegasco to reduce its reliance on seasonal gas supply reservations and to use less expensive alternatives that reduced Minnegasco's demand costs by approximately $15.5 million over the three years of the plan,

c. reductions in the amount of Northern Natural's Firm Field Area (TFF) pipeline transportation capacity allocated to Minnegasco. Minnegasco took various actions to reduce its demand costs which Minnegasco has designated as trade secret,

d. other measures that reduced its demand costs without compromising the quality of Minnegasco's firm service. Minnegasco has designated these measures as being trade secret. The amount of savings attributable to these actions was also designated trade secret,

e. an aggressive pursuit of opportunities to release pipeline capacity into the secondary market. This resulted in capacity release revenue of $8.2 million over three years, and

f. more efficient additions of pipeline capacity to meet the requirements of new customers. This has resulted in lower costs per customer due to decisions regarding the type and location of additional capacity and in an overall reduction in demand costs during the plan of $17.9 million.

The November 2, 1998 Minnegasco/Department Comments did not indicate whether these savings were expected to continue or disappear when Minnegasco's Plan expires.

In its November 17, 1998 comments, OAG argued that in this Plan, the demand cost savings achieved in one year would result in windfalls in the following years for the duration of the plan. If this type of benchmark were considered in the future, OAG argued that the benchmark would need to be designed to reward continuous improvement from one year to the next rather than providing continuous rewards for actions taken at a single point in time, e.g. reformation or reconfiguration of a single long-term pipeline transportation contract.

One design approach that OAG believes could be used, would be to reset the demand component each year of the plan. This would prevent windfall profits in one year from carrying over into the following year without any additional effort on the Company's part. If this approach were adopted in a future plan, it might also prevent losses in one year from carrying over into following years absent any mistakes (inadvertent or otherwise) on the Company's part.

It should be noted that demand costs appear to be the area of gas cost in which an incentive mechanism can accomplish the most. Unlike the market for the commodity supply of gas which is already competitive, the market for pipeline transportation service into Minnesota is dominated by one major pipeline, i.e. Northern Natural. While it is true that service on Northern is increasingly competitive and that to a certain extent alternative arrangements exist, Northern's rates are by and large still set by the Federal Energy Regulatory Commission. While this is slowly changing, competition in the market for pipeline services into Minnesota does not yet exist.

For the same reason that demand costs may be well suited to being controlled with the encouragement of a well designed incentive mechanism, i.e. the lack of a competitive market for pipeline services, the opposite however, is probably true for the commodity supply of gas, in which there is a relatively well developed competitive market. This observation highlights one of the central facts of gas supply into Minnesota: the market for the commodity supply of gas is fairly competitive and the market for firm pipeline capacity is relatively constrained. This aspect of gas supply in Minnesota makes the design of an appropriate PBR plan benchmark complicated.

VI. Concluding Comments

In their November 30, 1998 reply comments, Minnegasco and the Department noted that from start to finish, i.e. beginning with the drafting of the initial legislation, the design of Minnegasco's plan, the calculation of the three annual incentive awards, and concluding with the final end-of-plan evaluation, this has been a consensus driven, collaborative process.

Minnegasco and the Department believe that because of this process, valuable experience was gained by all parties regarding alternative forms of regulation and demonstrates that PBR is a workable supplement to rate of return, cost of service regulation.

The use of two models in Minnegasco's plan provided experience with three completely different performance benchmarks. This also was a valuable learning experience for all parties because setting performance benchmarks is the most problematic aspect of designing a performance-based incentive plan. For example, the longer a plan is in effect the higher the stakes will be, and the more difficult it will be to establish a fair and reasonable benchmark. As noted previously, a high statistical correlation between historical benchmark data and a Company's actual historical performance does not necessarily indicate or accurately predict the future relevance of a benchmark.

Another lesson learned from Minnegasco's plan was the need for some measure to ensure that only ongoing efforts are rewarded. To achieve this, the OAG recommended that a productivity offset should be incorporated into any future performance benchmarks. OAG also concluded that a "productivity" offset would counteract the unequal or asymmetrical access to information regarding the appropriateness of various performance benchmarks and the feasibility of Minnegasco's ability to control its own gas costs.

It should be noted that the various comments and analyzes did not indicate which measures, if any, were continued and/or discontinued by Minnegasco at the end of the Plan. The strategic evaluation and possible reconfiguration of an LDC's portfolio of pipeline transportation and storage contracts needs to be a continuous process. Otherwise, the LDC will not be able to take advantage of efficiency and cost saving opportunities as they arise. For example, costs can be controlled through more intensive day-to-day management of pipeline assets, more efficient use of long- and short-term commitments for pipeline assets to meet expansion needs, and ongoing negotiation of pipeline terms and conditions of service as well as rates.

It should also be noted that the comments and analyzes did not indicate whether Minnegasco added new resources at the beginning or during the plan to improve its chances of earning a reward and, if so, at what expense. If, on the other hand, resources were merely diverted from one area of the Company to another to achieve the incentive award, it would be interesting to find out what sort of activities were given up in order to accomplish the gas cost reductions described in the comments. The answer to those questions may shed some light on whether the plan was necessary for Minnegasco to control its costs and whether this was an effective statute?

The Commission does expect the measures taken by Minnegasco to control its costs during the term of the Plan to be lessons well learned and ones that can be continued even though the Plan has expired. The Commission is not aware of any reason why Minnegasco would discontinue any of these measures and would expect Minnegasco to strive to continue taking prudent actions that minimize its cost of gas.

Appendix A

Minnegasco/Department of Public Service
Comments

November 2, 1998

Minnegasco

...n of Houston Industries

November 2, 1998

** NON-PROPRIETARY **

Burl W. Haar, Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 East Seventh Place
St. Paul, MN 55101-2147

Re: In the Matter of the Commission's Report to the Legislature on Performance Based Gas Purchasing Plans;
Joint Filing by Minnegasco and the Department of Public Service on Minnegasco's Plan;
Docket No. G-008/CI-98-1219

Dear Dr. Haar:

Pursuant to Minn. Stat. §216B.167 (1995), the Commission must evaluate the effectiveness of all Performance-Based Regulation (PBR) plans approved under this section and submit its findings to the Legislature by January 1, 1999. In order to assist the Commission in the preparation of this Report, a work group was formed pursuant to the Commission's Order of March 12, 1998, ORDER ACCEPTING REPORT AND APPROVING INCENTIVE AWARD, in Docket No. G-008/M-95-465. In order to assist the work group, Minnegasco and the Minnesota Department of Public Service are jointly filing this summary of the results of Minnegasco's Performance-Based Gas Purchasing Plan, including all evaluation requirements of the statute. In general, this filing follows the outline of Minnegasco's annual PBR reports and also includes additional analysis where appropriate.

In summary, Minnegasco's Gas Purchasing PBR Plan was successful in providing the utility with the incentive to take actions which it would not have taken absent the Plan to achieve lower gas costs for consumers. During the three years of the Plan, Minnegasco out-performed the Plan's approved Benchmark which resulted in a financial incentive of nearly $28 million, with over $17 million going to customers. Based on the ability of PBR to benefit both utilities and its customers, as well as the success of Minnegasco's Plan, Minnegasco and the Department of Public Service recommend that the Commission's Report to the Legislature support the continuation of the Gas Purchasing PBR statute.

If there are any questions regarding this filing, please contact Joe Klenken at 321-4677 or me at 321-4753 on behalf of Minnegasco or Scott Brockett at 296-7531 or Vince Chavez at 296-0404 on behalf of the Department of Public Service.

Sincerely,

Doug Peterson

Douglas W. Peterson
Associate Director, Regulatory Services

/mjs
Attachments
cc: Attached Service List

Evaluation of Minnegasco's Performance-Based Gas Purchasing Plan
Submitted Jointly by Minnegasco and The Department of Public Service
Docket No. G-008/CI-98-1219
November 2, 1998

Executive Summary

In 1996, the Minnesota Public Utilities Commission approved a Performance-Based Gas Purchasing Plan (PBR Plan) for Minnegasco pursuant to Minn. Stat. §216B.167. Minnegasco's PBR Plan was a collaborative result of settlement discussions between the Department of Public Service, the Office of the Attorney General and Minnegasco. The Commission approved a 3-year (September 1995-June 1998) Plan that would compare Minnegasco's actual performance under the Plan to pre-determined benchmarks. Based on Minnegasco's actual performance, a calculation would be made each year to determine whether a PBR reward or penalty would apply to Minnegasco.

The Plan is structured around the results of two performance-based models: a local distribution company (LDC) Component and a Commodity/Demand Component. The LDC Component compared Minnegasco's performance to the actual performance of the three largest LDCs in Minnesota other than Minnegasco. The Commodity/Demand Component compared Minnegasco's actual commodity and demand costs to benchmarks that serve as reasonable measures of what Minnegasco's costs would have been in the absence of the PBR Plan. Based on the incentives provided by the Plan, Minnegasco took many actions that it would not have otherwise taken to reduce its gas costs. For example, to lower its demand costs, Minnegasco reduced its supply reservation fees, increased its load factor, made effective use of capacity release opportunities, and improved its efficiency in using pipeline capacity. To reduce its commodity costs, Minnegasco placed a higher priority on and improved its performance in effectively using its supply portfolio. Minnegasco constantly analyzed and monitored daily market conditions to lower its commodity costs, efficiently used its third party storage facilities, and took other actions to lower commodity costs. The incentives provided by the Plan caused Minnegasco to take these actions.

As a result of these actions, Minnegasco continuously improved its performance under the Plan. The Plan has provided incentives to Minnegasco to lower gas costs which have resulted in total net incentives of approximately $27.9 million. The $27.9 million net incentive was calculated based on Minnegasco's performance relative to the Benchmark and the deadband, sharing provisions and incentive caps specified by the Plan. The amount of the incentive retained by customers was approximately $17.4 million. The amount retained by Minnegasco, in the form of a reward for its actions, was approximately $10.5 million.

Minnegasco and the Department believe that the Plan gave Minnegasco the incentive to take actions to lower its gas costs that it would have not otherwise taken without the Plan. These actions reduced Minnegasco's overall gas costs and benefited both Minnegasco and its customers. Minnegasco and the Department believe that Minnegasco's Plan has been successful in meeting the goal of PBR, which is to produce net benefits for all customers by linking financial rewards and penalties to the utility's performance. In addition, Minnegasco's Plan has provided valuable experience to Minnegasco and other parties that will be useful in future PBR applications. Based on the ability of PBR to benefit both utilities and their customers, Minnegasco and the Department recommend that the Commission's report to the Legislature support the continuation of gas purchasing PBR enabling legislation contained in Minn. Stat. §216B.167.

I. Introduction

On August 7, 1995, Minnegasco, a division of NorAm Energy Corp. (Minnegasco), filed a petition for approval of a performance-based gas purchasing plan (PBR Plan) pursuant to Minn. Stat. §216B.167 (see Attachment A). On May 21, 1996, the Minnesota Public Utilities Commission (Commission), issued its Order approving Minnegasco's PBR Plan as modified by a settlement among the Department of Public Service (the Department), the Office of the Attorney General (OAG) and Minnegasco. In the Joint Offer of Settlement (Settlement) approved by that Order, Minnegasco agreed to a file a report by November 1 of each year of the Plan that includes the calculation of the PBR reward or penalty and various other related information required to evaluate the Plan. Minnegasco has filed annual PBR reports each year of the Plan including all required information needed to evaluate the Plan. This report covering all three years of the Plan was prepared to assist the Commission in the preparation of its Report to the legislature on Gas Purchasing PBR Plans, as required by Minn. Stat. §216B.167, subd. 7.

II. Plan Evaluation

The Statute, under subd. 4 (Plan Evaluation), provides that "the commission shall evaluate the various customer and utility impacts...including the impact on customer bills over time, the impact on utility revenues, and the effectiveness of the plan in meeting the purposes contained in subdivision 1. Subd. 1 contains the following four purposes:

(1) The plan provides incentives for the utility to achieve lower natural gas costs than would have been achieved in the absence of the plan, as measured by the benchmarks established in clause (3), by linking financial rewards and penalties to natural gas costs;

(2) The potential benefits of the plan apply, at a minimum, to each customer class purchasing firm natural gas service from the utility;

(3) The plan establishes one or more benchmarks against which actual natural gas costs will be measured and the benchmarks reflect relevant market conditions and represent reasonable and achievable natural gas costs in Minnesota for the term of the plan; and,

(4) The plan provides that the utility cannot curtail or interrupt service to any customer class purchasing firm service during the term of the plan except for causes outside the reasonable control of the utility or causes not directly related to the gas purchasing practices of the utility.

In this report, Minnegasco and the Department outline the effectiveness of the Plan in meeting the purposes of the Statute and provide all other information needed to evaluate the Plan. As demonstrated in this report, Minnegasco's PBR Plan provided incentives for Minnegasco to achieve lower natural gas costs than would have been achieved without the Plan. The Plan provided meaningful incentives for Minnegasco to undertake prudent risks in securing its portfolio of supply, transportation and related services, while maintaining reliability and service quality. In each year of the three-year Plan, Minnegasco achieved its goal under the Plan of producing lower costs for ratepayers.

III. Summary of Plan Results

Minnegasco out-performed the established Benchmark in each year of the Plan by the following amounts:

	Customer Incentives	Minnegasco Incentives	Total Net Incentives
Year One	$3,244,794	$1,102,734	$4,347,528
Year Two	$6,600,400	$3,980,205	$10,580,605
Year Three	$7,589,972	$5,395,761	$12,985,733
Totals	$17,435,166	$10,478,700	$27,913,866

Note: Year Three results were filed on October 7, 1998, and are pending Commission review.

The complete derivation of the incentives is shown on Attachment B and discussed in Section 4. Minnegasco's Plan contains three components, Demand/Commodity and other LDC. The $27.9 million net incentive was calculated based on Minnegasco's performance relative to the Benchmark and the deadband, sharing provisions and incentive caps specified by the Plan.

The Plan provided an incentive for Minnegasco to take actions to lower its gas costs and produced benefits for Minnegasco's customers. Over the past three years, due to the existence of the Plan, Minnegasco has undertaken several different strategies and tactics to manage its gas supply and capacity portfolio in order to lower costs without reducing service quality. The Plan produced positive benefits to both customers and Minnegasco.

IV. Calculation and Discussion of PBR Results

The PBR Plan produced total net incentives of approximately $27.9 million with each year's incentive based on Minnegasco's performance relative to the Benchmark and the deadband, sharing and various caps specified by the Plan. The customers' share was approximately $17.4. Minnegasco's share was approximately $10.5 million.

Under the Plan, the results of two performance-based models are combined: Model 1, the LDC Component, and Model 2, the Commodity/Demand Component (see Attachment B). Minnegasco did not out-perform the LDC Benchmark during the three years of the Plan. However, in Year Three, its performance was greatly improved compared to prior years. In each year, Minnegasco out-performed the Commodity/Demand Benchmark. The combined result reflects an overall reduction in gas costs under the Plan and a sharing of incentives between customers and Minnegasco.

A. LDC Benchmark:

The LDC Benchmark compared Minnegasco's average total unit cost of gas to the sales weighted average total unit gas cost for the three largest LDCs in Minnesota (other than Minnegasco): Northern States Power (NSP), Peoples Natural Gas (Peoples) and Northern Minnesota Utilities (NMU). Minnegasco's gas costs were higher than the LDC Benchmark in each year of the Plan (see Attachment B), resulting in a penalty in each year from this component of the Plan. However, as mentioned earlier, the results of the LDC Component were greatly improved in the third year of the Plan. In the first two years of the Plan, the per-unit differentials were $.0871/DT and $.0890/DT, respectively (see Attachment C). The third-year result of $.0056/DT higher than the LDC Benchmark represented a significant improvement by Minnegasco compared to the first two years of the Plan. The penalties related to the LDC Benchmark were approximately $14.5 million (see Attachment B) for the three years of the Plan. In Years One and Two, the penalty was capped per the requirements of the Plan. The incentives provided by the Plan, including the existence of penalties for under-performing, produced the significant improvement in Minnegasco's performance relative to the LDC Benchmark during Year Three of the Plan.

B. Commodity/Demand Benchmark:

The Commodity/Demand Benchmark compared Minnegasco's actual unit commodity and weather-normalized unit demand costs to benchmarks that serve as reasonable approximations of what Minnegasco's costs would have been in the absence of the PBR Plan. Over the term of the Plan, Minnegasco's unit commodity cost averaged $0.064/DT less than the Commodity Benchmark (see Attachment C) which represents approximately $27 million in commodity cost reductions compared to the Benchmark (see Attachment B). Minnegasco out-performed the benchmark by approximately $4.6 million, $13.8 million and $8.5 million for Years One, Two and Three, respectively. The Commodity Benchmark is equal to the sales weighted average of each month's market price as represented by "Inside FERC's" Gas Market Report price listing at Ventura, Iowa with adjustments for fuel, Northern Natural Transportation charges and lost and unaccounted for gas on Minnegasco's system.

Over the term of the Plan, Minnegasco's unit demand cost averaged over $0.14/DT less than the Demand Benchmark, reducing demand costs by approximately $43.4 million (see Attachment B). Minnegasco improved its performance each year, out- performing the benchmark by approximately $10.1 million, $15.2 million and $18.2 million for Years One, Two and Three, respectively. The Demand Component of the Benchmark was based on the amount of pipeline capacity Minnegasco had under contract in the base year multiplied by Minnegasco's current cost for that pipeline capacity and divided by Minnegasco's actual number of firm customers multiplied by the average amount of gas used in the base year by a firm customer. The performance relative to both the Commodity and Demand Benchmarks reflected specific actions that Minnegasco took over the past three years due to the incentives created under the PBR Plan. These specific actions are discussed later in this report.

The Plan averages the results from Model 1 and Model 2, thus each component balances the other. After averaging the components, a "deadband" was applied where all costs or savings were passed through to ratepayers. The "deadband" represents one-half percent of the benchmarks. The "deadband" ensures that only incentives 0.5% higher or lower than the benchmark qualify for sharing. The remaining amount represents the sharing zone where costs or savings were shared equally between ratepayers and Minnegasco (see Attachment B). Over the course of the Plan, Minnegasco's unfavorable performance in Model 1 (LDC Component) was more than offset by its very favorable performance in Model 2 (Commodity/Demand Component). As discussed earlier, the Plan has provided incentives to Minnegasco to lower gas costs which have resulted in total net incentives of approximately $27.9 million, based on the Plan's three benchmark components, deadband, sharing provisions and various incentive caps.

V. Discussion of Plan Evaluation Requirements

As set forth above, the Statute requires the following plan evaluation requirements to be addressed.

A. Customer Impact

The impact of the Plan has been lower gas costs billed to customers. During each year of the Plan, Minnegasco out-performed the benchmark. The result was lower gas costs, for the three years, of approximately $24, $131 and $1,091 for typical residential, commercial and industrial customers, respectively. These reductions were partially offset by PGA surcharges billed to customers to recover Minnegasco's incentive for out-performing the benchmark. The net impact on a typical residential customer was approximately $15 in lower gas costs over the three years of the Plan. Averaged-sized firm commercial and industrial customers realized net reductions of approximately $82 and $681, respectively (see Attachment D).

B. Impact on Utility Revenue

The customers' incentive exceeded $17 million during the term of the Plan. Although this is a substantial reduction, the impact on Minnegasco's total revenue was less than a 1% reduction (see Attachment E). Minnegasco averaged over 140,000,000 DT of sales a year during the three years of the Plan, generating annual revenues averaging approximately $660 million a year.

C. Service Quality

Minnegasco's firm customers enjoyed safe, reliable and uninterrupted service during the Plan. The actions which Minnegasco took to reduce gas costs did not jeopardize the reliability of service. Minnegasco's gas-control, gas-dispatch and peak-shaving plant operators found ways to buy, schedule and deliver reliable and cost effective supplies to maintain service quality for all customers.

D. Effectiveness of Meeting the Purposes of Subdivision 1 of the Statute

As discussed above, the Plan Evaluation must address the effectiveness of the Plan in meeting the purposes of subdivision 1 of the Statute. Minnegasco and the Department believe the Plan was effective in meeting these purposes. The purposes are addressed throughout this report and the following summary is provided:

1. The benchmarks established in the Plan provided significant incentives for Minnegasco to take actions to achieve lower natural gas costs. These incentives totaled approximately $27.9 million during the term of the Plan.
2. The benefits of the plan applied to each customer class purchasing firm natural gas service from Minnegasco.
3. The Plan established three benchmarks (LDC, Demand, and Commodity) against which Minnegasco's actual gas costs were compared. These benchmarks were closely correlated to performance prior to the Plan and, therefore, they reflected relevant market conditions and represented reasonable and achievable gas costs during the term of the Plan.
4. The Plan provided for no curtailment or interruption of service to firm customers. In fact, no firm customers were interrupted during the term of the Plan.

VI. Actions taken to Lower Gas Costs

A. LDC Component

The third year results of the LDC Component benchmark showed a significant improvement over the first two years of the program. To a great extent, this significant improvement was due to two factors; the specific actions Minnegasco took to reduce its gas costs and, actions taken by other gas utilities included in this component.

Due to the incentives provided by the Plan, Minnegasco has revised its mix of gas supply purchases and interstate pipeline capacity, negotiated discounts from suppliers and dedicated additional resources to identify opportunities to lower gas costs. These actions have produced significant reductions in demand and commodity gas costs. The accumulation of three years of reducing gas costs resulted in Minnegasco's significant improvement made relative to the LDC component in Year Three.

B. Changes in Demand Cost

Minnegasco made several changes to its gas supply and capacity portfolio as a result of the incentives provided by the Plan. Many of these changes lowered demand costs paid to pipelines and gas suppliers. During the three years the Plan was in effect, Minnegasco reduced seasonal supply reservation fees, reduced its overall level of firm field area capacity, ***PROPRIETARY*** ***END PROPRIETARY*** and improved its split between TF12 base and TF12 variable billing units. All of these actions led to reduced demand costs. At the same time Minnegasco was able to meet customer growth by adding pipeline capacity under either discounted rates or the most favorable rates available. A thorough description of these actions follows:

1. <u>Northern's TF12 Base and TF12 Variable Transportation Charges</u>

   Minnegasco was able to reduce annual demand costs related to the split between TF12 Base and TF12 Variable billing units by a total of $1.6 million during the three years of the Plan (see Attachment F). Annually, Northern calculates the volume of natural gas transported on its pipeline by each utility during the months of May through September and uses each utility's average daily volumes to assign each utility's split between TF12 Base and TF12 variable units. Northern's TF12 Base rates are lower than TF12 Variable rates, therefore, if a utility is able to transport more gas on Northern's pipeline during May through September its demand costs will be reduced. In effect, the utility is rewarded for a higher system load factor. Minnegasco improved its system load factor by increasing its throughput on Northern's pipeline during the summer months. Minnegasco was able to increase its throughput on Northern from May through September during the Plan by delivering gas to its third party storage facility via Northern's pipeline and marketing increased usage to electric generation and other large volume customers during this off-peak period. In general, Minnegasco was also able to reduce transportation costs and purchase lower cost gas by using Northern's pipeline during these off-peak periods.

2. Seasonal Reservation Fees

Minnegasco reduced seasonal reservation fees each year of the Plan (see Attachment F). The reduction of these costs was a major reason why Minnegasco was able to out-perform the Demand Benchmark each year. Seasonal reservation fees are paid to gas suppliers to ensure delivery of firm gas supplies. The reduction in seasonal reservation fees was accomplished through the following actions: First, Minnegasco replaced firm gas supply contracts that had swing capability with baseload contracts with lower reservation fees. Second, Minnegasco eliminated firm supply contracts with reservation fees it previously held to ensure availability of supply reserve with monthly contracts in the coldest months and daily contracts in the shoulder months. These actions resulted in a reduction in demand costs of approximately $15.5 million over the three years of the Plan. These methods proved to be effective in reducing gas costs but they required intensive monitoring and careful management.

Minnegasco also implemented changes in daily gas supply planning to allow wider input, develop broader consensus, and improve coordination of Throughput Management and Gas Supply staff. Coordination and planning meetings were held daily at 7:00 a.m. One example of the effectiveness of constant coordination and planning was demonstrated in the second year of the Plan during a severe winter, when Minnegasco incurred only $953 of pipeline imbalance penalties.

3. Firm Field-Area Pipeline Capacity

Minnegasco was successful in reducing its annual units of Firm Field Area Pipeline capacity (TFF) which were acquired as a result of Northern's Global Settlement in 1993. ***PROPRIETARY***

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4. Pipeline Transportation Charges

Minnegasco worked with interstate pipelines to secure substantial reductions in transportation charges without jeopardizing system reliability. ***PROPRIETARY***

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5. Capacity Release

Minnegasco aggressively released capacity whenever operationally, contractually and financially possible in order to maximize the reduction of gas costs. Over the course of the Plan, Minnegasco achieved over $8.2 million of capacity release revenue (see Attachment F). During the third year of the Plan, Minnegasco's capacity release activities involved more than 160 transactions with 21 different parties. At the start of the Plan, Minnegasco made the decision to dedicate more resources to capacity release activities. This decision proved to be very successful in reducing demand costs and as a result, Minnegasco exceeded the $2.2 million capacity release benchmark included in the Model 2 Demand component each year of the Plan.

6. More efficient use of capacity

Each year of the Plan, Minnegasco increased the efficiency of its use of interstate pipeline capacity and reserved firm supplies. Minnegasco reduced overall demand costs while at the same time adding pipeline capacity to serve new customers. Minnegasco has met the demands of its customers at a lower cost per customer due to decisions it made regarding the type and location of additional capacity. Minnegasco's actual demand costs decreased significantly during the Plan, from $1.313/DT during Year One to $1.123/DT during Year Three of the Plan. As described above, annual demand cost reductions have been realized by increasing the load factor, reducing seasonal reservation fees, ***PROPRIETARY***

END PROPRIETARY and aggressively releasing capacity when its not needed. In addition to these specific actions, Minnegasco's overall improvement in capacity efficiency produced $17.9 million in lower demand costs during the Plan.

Summary of Demand Costs

Due to the incentives provided by the Plan, Minnegasco significantly reduced its annual demand costs below the pre-Plan level and has outperformed the Demand Component of the Plan by an average of nearly $14.5 million per year during the three years of the Plan.

C. Changes in Commodity Costs

During the three years of the Plan, market commodity costs were extremely volatile. Market commodity costs hit an all time high during the winter of 1996-97 and then decreased by 10% over the next year. Extreme price fluctuations on a daily and monthly basis often occurred. When fluctuations occurred, Minnegasco diligently balanced the utilization of third party storage, daily contracts and system efficiencies to reduce commodity gas costs. Minnegasco reorganized, redesigned work areas and dedicated additional resources to the Gas Supply and Gas Control departments at the start of the Plan. These organizational improvements resulted in improved coordination and communication in its gas supply department which generated timely decisions producing the most cost effective use of its supply portfolio.

Whenever possible, Minnegasco used its third party storage to avoid the use of more costly first-of-the-month priced supplies and to minimize the purchase of expensive short-term supplies. ***PROPRIETARY***

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END PROPRIETARY*** Minnegasco carefully managed injections and withdrawals of storage gas to take advantage of lower prices or to avoid higher prices whenever possible. As a result, Minnegasco purchased almost no expensive short-term peaking supply during the peak heating months of December through February by effectively using its third party storage program.

Constant analysis and monitoring of daily market conditions produced gas cost reductions. Minnegasco constantly monitored daily market prices and, whenever a price advantage could be gained, used daily purchases to lower gas costs. However, during the mild winter of 1997-98, lower market commodity costs and fairly stable daily rates did not provide Minnegasco with as many opportunities to use the daily market to lower commodity costs as it had seen in prior years.

In the third year of the Plan, Minnegasco also significantly reduced commodity costs by renegotiating two major components of its portfolio. ***PROPRIETARY***

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Summary of Commodity Costs

Due to the incentives provided by the Plan, Minnegasco was able to purchase gas supplies at very competitive prices during the three years of the Plan and outperformed the Commodity Component Benchmark each year. The commodity cost reduction averaged approximately $9 million per year during the Plan (see Attachment B).

VII. Analysis of Performance During the Plan

Minnegasco's total performance improved each year of the Plan. The incentives were $4.3 million, $10.6 million and $13 million for Years One, Two and Three, respectively. However, Minnegasco's performance on the different benchmark components varied from year to year during the Plan. Minnegasco's performance relative to the Model 1 Benchmark (LDC Component) was worse in Year One compared to the previous year, improved slightly between Years One and Two, and further improved between Years Two and Three (see Attachment C). At the end of the Plan, Minnegasco's average cost of gas was only $.0056/DT higher than the LDC Benchmark, whereas, in Year One it was $.0871/DT higher.

Minnegasco out-performed the Commodity Component Benchmark of Model 2 each year of the Plan (see Attachment C). The largest differential between the Benchmark and actual commodity costs occurred in Year Two of the Plan where Minnegasco out-performed the Benchmark by $.0943/DT resulting in reduced commodity costs of $13.8 million. In Year Two, market commodity costs were very high with large monthly and daily price swings. During this time of high and volatile prices, Minnegasco was able to purchase gas at the most cost effective prices by diligently monitoring the daily market and ***PROPRIETARY***

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Minnegasco's performance relative to the Demand Component Benchmark of Model 2 improved each year of the Plan (see Attachment C). The cost per unit ($/DT) differential between the Demand Benchmark and actual Demand costs increased steadily from a $.1007/DT reduction in Year One to a $.1477/DT reduction in Year Two and, finally, a reduction of $.1733/DT in Year Three. The actions Minnegasco took to continually improve its performance were described in detail in the previous section of this report.

VIII. Analysis Comparing Performance During the Plan to Performance Prior to the Plan

Attachment C provides an analysis of Minnegasco's performance relative to the Model 1 Benchmark (LDC Component) and Model 2 Benchmark (Demand/Commodity Component) for the three years prior to the start of the Plan and the three years of the Plan. Minnegasco went from a position of being approximately $.005/DT lower, on average, than the average per unit cost of the three other utilities to being higher, on average, by $.061/DT. Minnegasco had no direct control over the performance of the other utilities as used in this Benchmark and, therefore, cannot explain all of the reasons for this result. In any event, Minnegasco believes it has reversed the trend of increasing cost differentials between itself and the other three utilities (see Attachment C).

Minnegasco could and did take specific actions to control its commodity costs. Minnegasco's average commodity costs went from a position of being higher than the Commodity Benchmark by approximately $.023/DT, on average, for the three years prior to the start of the Plan, to being lower than the Commodity Benchmark by approximately $.064/DT, on average, for the three years of the Plan. Minnegasco demonstrated significant improvement in lowering its commodity costs during the Plan.

An analysis comparing the Demand Component's performance during the Plan to performance prior to the Plan cannot be made since the Benchmark was set on a base year concept. However, it is clear from Minnegasco's performance, relative to the Demand Benchmark that numerous and innovative cost-saving actions were accomplished during the Plan. These actions were described in detail earlier in this report and they generated reduced demand costs of approximately $43.4 million during the three years of the Plan. As mentioned earlier, Minnegasco's actual demand costs decreased significantly during the Plan, from $1.313/DT during Year One to $1.123/DT during Year Three of the Plan.

IX. Summary of Other Reporting Requirements included in Annual Filings

A. Purchases from and sales of gas and capacity to affiliated interests

Minnegasco conducted certain transactions with affiliated interests for the purchase of natural gas each year of the Plan. Minnegasco purchased gas from NorAm Energy Services, Inc. (NES), an affiliated company, pursuant to the authority granted under Docket Nos. G-008/AI-91-217, G-008/AI-91-471 and G-008/AI-97-1268. The first two approved contracts listed have been in place since 1991 and have provided Minnegasco with reliable and competitively priced natural gas since then. The contract in the last docket listed was approved for this past heating season, November 1997 through March 1998. This contract with NES related to required purchases at Carlton, Minnesota and, as mentioned earlier, contributed to Minnegasco's decrease in commodity costs related to its required purchases at Carlton during the third year of the Plan.

B. Storage purchases, injections, withdrawals and related costs

As part of the settlement, Minnegasco agreed to provide an analysis of the effect of storage in its annual reports in order to gain insights and clarify the benefits and costs related to alternative methods of accounting for gas costs. Information on all storage purchases, injections, withdrawals and costs, along with the hypothetical impact of the "unit of purchase" approach on the PBR results, was provided in the annual report each year. This analysis has shown that in two out of three years of the Plan, reported gas cost savings would have been higher using the "unit of purchase" approach (i.e., Minnegasco would have received a larger reward). Overall, seasonal price differentials related to storage produced slightly higher gas cost incentives during the term of the Plan (see Attachment G). This was caused by market commodity costs that were extremely high in the winter of Year Two (a very cold winter), resulting in an abnormally large seasonal price differential.

C. Peak-shaving plant expenditures and acquisitions

In accordance with the Commission's Order, Minnegasco included $74,804 of operation and maintenance expense as "demand costs" for the purpose of Plan calculations, related to the peaking facility in Alexandria, Minnesota. This expense was derived from Minnegasco's 1995 rate case, Docket No.G-008/GR-95-700. No other peak shaving plants were acquired or constructed during the Plan. The Alexandria peaking facility was operational for the 1997-98 heating season and was used to supplement supply when needed.

D. Changes in capacity planning criteria

Minnegasco did not implement any changes in its capacity planning criteria. Minnegasco experienced near design-day conditions on its system during the winter of 1995-96. Actual demand was within 1% of forecasted design day demand. Minnegasco is confident that its design day forecasting methods provide an accurate assessment of firm design day requirements.

Minnegasco slightly reduced its level of reserved transportation capacity during the Plan. Minnegasco continued to evaluate the appropriateness of its transportation reserve level. If lower gas costs could be achieved, without jeopardizing reliability, changes to the reserve level would be made. However, there were no substantial reductions in Minnegasco's reserve level during the three years of the Plan. Minnegasco's reserve margin was 4.7% at the start of the Plan and 4.0% at the end.

	Capacity Reserve DT	Design Day Requirements DT	Percentage
1994-95	49,875	1,068,087	4.7%
1995-96	49,283	1,080,514	4.6%
1996-97	47,929	1,100,868	4.4%
1997-98	45,090	1,128,707	4.0%

Minnegasco continues to maintain capacity sufficient to guarantee safe and reliable service in the event some suppliers or peaking facilities fail.

E. Changes in planned or acquired capacity additions

Minnegasco added pipeline entitlement each year of the Plan in order to meet the requirements of customer growth. Minnegasco was able to add pipeline entitlements at either discounted rates or the most cost-effective pipeline rates available. For example, for the past heating season (1997-98), Minnegasco added 20,000 units per day of firm transportation on Viking's pipeline to meet firm customer growth on its system. Minnegasco was able to take advantage of Viking's lower cost transportation service through the use of the Minnesota Intrastate Pipeline (MIPC) connections at Cambridge, MN. Minnegasco continued to add pipeline capacity to meet customer growth in order to continue to reliably serve all firm customers.

X. Conclusion

Based on the results of Minnegasco's Performance-Based Gas Purchasing Plan, the Plan was successful in providing Minnegasco with incentives to identify and implement new and innovative ways to lower gas costs for Minnegasco customers. As previously described, the Plan produced total incentives of approximately $27.9 million compared to the Benchmark, with customers retaining approximately $17.4 million and Minnegasco retaining approximately $10.5 million.

As stated in Minnegasco's original filing of August 7, 1995, Performance-Based Regulation is an alternative form of regulation that holds great potential to meet optimally objectives of regulation. The goal is to produce net benefits for all customers by linking financial rewards and penalties to utility performance. Upon review, Minnegasco's Plan has met this goal and has provided valuable experience to Minnegasco and regulators. Based on the ability of PBR to benefit both utilities and its customers, Minnegasco and the Department recommend that the Commission's Report to the Legislature support the continuation of Gas Purchasing PBR enabling legislation contained in Minn. Stat. §216 B.167. Specifically, we recommend that the Commission support the repeal of the sunset provision in subdivision 8 of the Statute.

Minnegasco and the Department appreciate this opportunity to provide information to the Commission on its PBR Plan.

ATTACHMENTS

A STATUTE 216B.167 Performance-Based Gas Purchasing Plans.

B Minnegasco's PBR Plan – Calculation by Year.

C Page 1: Benchmark Historic Trends -- Graph.

Page 2: Benchmark Historic Trends -- $/DT.

D Financial Impact on Customers

E Impact on Minnegasco Revenue

F Summary of Major Demand Cost Reductions (contains Trade Secret information).

G Summary of "Unit of Sale" versus "Unit of Purchase" Methods relating to Commodity Benchmark.

216B.167 PERFORMANCE-BASED GAS PURCHASING PLANS.

Subdivision 1. **Performance-based gas purchasing plans.** A public utility that furnishes natural gas may petition the commission for approval of a performance-based gas purchasing plan under this section. The commission may approve a plan if it finds that:

(1) the plan provides incentives for the utility to achieve lower natural gas costs than would have been achieved in the absence of the plan, as measured by the benchmarks established in clause (3), by linking financial rewards and penalties to natural gas costs;

(2) the potential benefits of the plan apply, at a minimum, to each customer class purchasing firm natural gas service from the utility;

(3) the plan establishes one or more benchmarks against which actual natural gas costs will be measured and the benchmarks reflect relevant market conditions and represent reasonable and achievable natural gas costs in Minnesota for the term of the plan; and

(4) the plan provides that the utility cannot curtail or interrupt service to any customer class purchasing firm natural gas service during the term of the plan except for causes outside the reasonable control of the utility or causes not directly related to the gas purchasing practices of the utility.

Subd. 2. **Sharing mechanism.** A plan must include a mechanism through which the utility shares with its customers the difference between actual natural gas costs and the plan's benchmark costs during the term of the plan. A plan must provide details of the sharing mechanism and may include an allowed level of costs above and below the benchmark before any sharing is to take place. The commission must determine an appropriate percentage of the difference between the benchmark and actual natural gas costs to be shared between customers and the utility. The sharing mechanism shall be implemented annually under section 216B.16, subdivision 7a. Financial rewards or penalties under the plan shall not be considered in the determination of the utility's revenue requirements in a general rate case pursuant to section 216B.16.

Subd. 3. **Reliability of service.** A plan must allow for the imposition of penalties if the standard for reliability of service established in subdivision 1, clause (4), is not met.

Subd. 4. **Plan evaluation.** A plan must include an evaluation process and mechanism that is reasonable and capable of supporting a full review of the utility's performance under the plan. The commission shall evaluate the various customer and utility impacts of a plan based on this evaluation process and mechanism, including the impact on customer bills over time, the impact on utility revenues, and the effectiveness of the plan in meeting the purposes contained in subdivision 1. The evaluation must occur within a reasonable time following the end of the plan.

Subd. 5. **Annual reporting.** The utility shall provide an annual report to the commission documenting its performance in meeting the requirements of the plan. Upon review of this report, the commission shall determine and approve rewards or penalties as provided in the plan.

Subd. 6. **Adoption.** A plan may be filed and approved within a miscellaneous tariff filing pursuant to section 216B.16. The commission may approve, reject, or modify the plan in a manner which meets the requirements of this section. An approved plan is effective for a period of not less than two years unless:

(1) the plan is withdrawn by the utility within 30 days of a final appealable order approving the plan; or

(2) the commission, after notice and hearing, rescinds or amends its order approving the plan.

Subd. 7. **General evaluation.** The commission must evaluate the effectiveness of all plans approved under this section and submit its findings to the legislature by January 1, 1999.

Subd. 8. **Expiration.** This section expires January 1, 2000. All plans must expire no later than December 31, 1999.

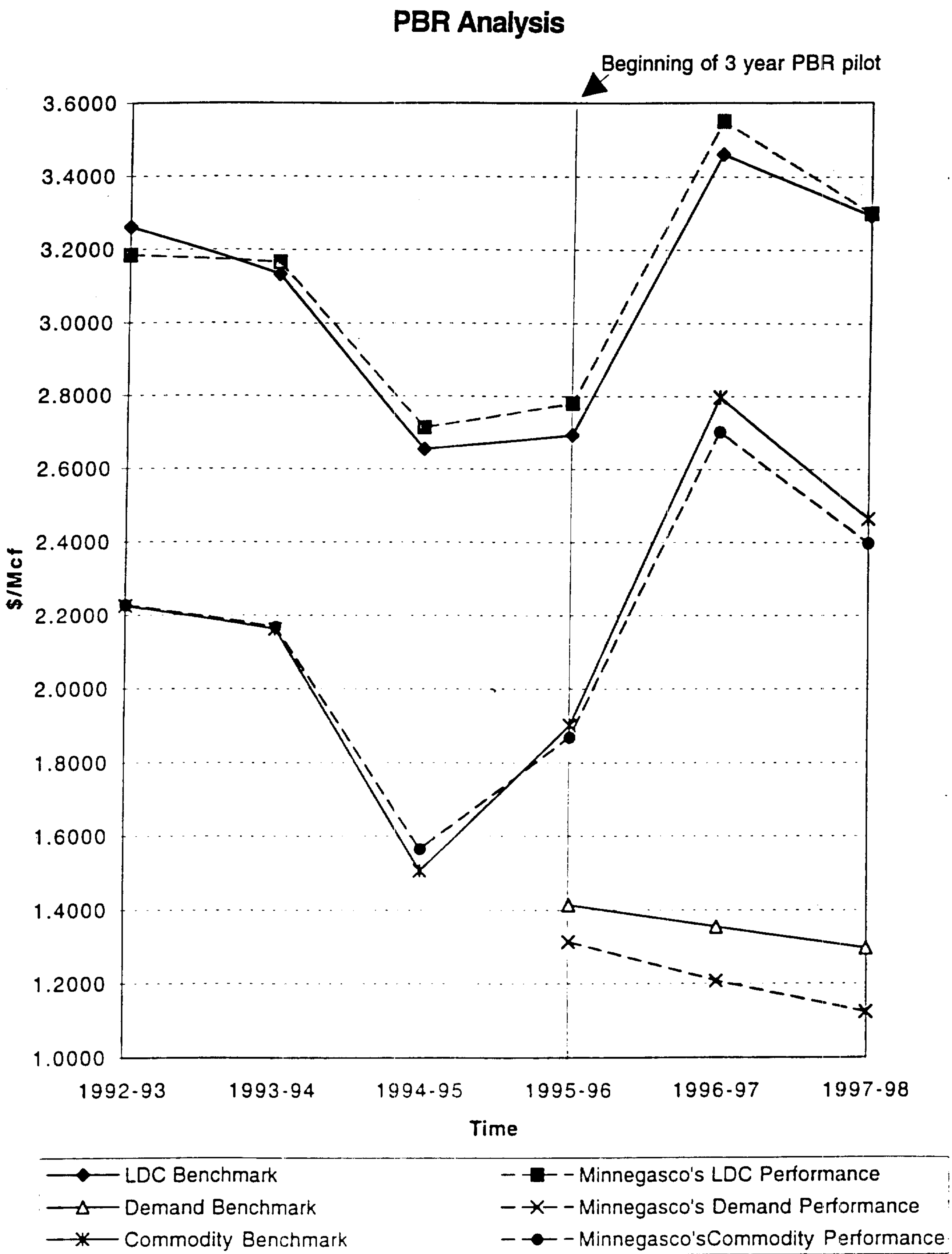
Minnegasco - PBR Plan Evaluation

Summary by Year

		Year One		Year Two		Year Three	Total
Model 1	LDC Component	($6,022,890)	Cap @ 1.5%	($7,785,878)	Cap @ 1.5%	($730,059)	($14,538,827)
Model 2							
	Demand Component	$10,112,815		$15,156,529		$18,162,442	$43,431,786
	Commodity Component	$4,605,130		$13,790,559		$8,539,083	$26,934,772
	Total Model 2	$14,717,945		$28,947,088		$26,701,525	
	Total Model 1 & 2	$8,695,055		$21,161,210		$25,971,466	
	Average of Models 1 &2	$4,347,528		$10,580,605		$12,985,733	
	Total Incentive	**$4,347,528**		**$10,580,605**		**$12,985,733**	**$27,913,866**
	Deadband	($2,005,241)		($2,620,195)		($2,194,212)	
	Incentive to be shared	$2,342,287		$7,960,410		$10,791,521	
	Ratepayer/Shareholder 50% split	$1,171,143		$3,980,205		$5,395,761	
	First year Proration	$1,102,734					
	Minnegasco's Incentive	**$1,102,734**		**$3,980,205**		**$5,395,761**	**$10,478,700**
	Customer Incentive	**$3,244,794**		**$6,600,400**		**$7,589,973**	**$17,435,167**

Note: The LDC component contained a Cap of 1.5% of Minnegasco's gas costs. In Years One and Two of the Plan the Cap was reached. The uncapped amounts for the LDC component in Years One and Two were ($12,573,881) and ($13,015,480), respectively.

Attachment B


PBR Analysis
Beginning of 3 year PBR pilot
3.6000
3.4000
3.2000
3.0000
2.8000
2.6000
2.4000
2.2000
2.0000
1.8000
1.6000
1.4000
1.2000
1.0000
$/Mcf
1992-93
1993-94
1994-95
1995-96
1996-97
1997-98
Time
LDC Benchmark
Demand Benchmark
Commodity Benchmark
Minnegasco's LDC Performance
Minnegasco's Demand Performance
Minnegasco'sCommodity Performance

Minnegasco

PBR Analysis

Trends by Component

Model 1 - LDC Component

		Benchmark	Minnegasco	Difference	Percentage Difference versus Benchmark	3 Year Average
	1992-93	$3.2599	$3.1833	($0.0766)		
	1993-94	$3.1329	$3.1650	$0.0321		
	1994-95	$2.6548	$2.7140	$0.0592	2.2%	$0.005
Year One	1995-96	$2.6943	$2.7814	$0.0871	3.2%	
Year Two	1996-97	$3.4603	$3.5493	$0.0890	2.6%	
Year Three	1997-98	$3.2937	$3.2993	$0.0056	0.2%	$0.061

Model 2 - Commodity Component

		Benchmark	Minnegasco	Difference	Percentage Difference versus Benchmark	3 Year Average
	1992-93	$2.2249	$2.2278	$0.0029		
	1993-94	$2.1614	$2.1689	$0.0075		
	1994-95	$1.5063	$1.5644	$0.0581	3.9%	$0.023
Year One	1995-96	$1.9001	$1.8682	($0.0319)	-1.7%	
Year Two	1996-97	$2.7975	$2.7032	($0.0943)	-3.4%	
Year Three	1997-98	$2.4627	$2.3971	($0.0655)	-2.7%	($0.064)

Model 2 - Demand Component

		Benchmark	Minnegasco	Difference	Percentage Difference versus Benchmark	3 Year Average
	1994-95	Base Year- No comparison can be made				
Year One	1995-96	$1.4137	$1.3130	($0.1007)	-7.1%	
Year Two	1996-97	$1.3543	$1.2066	($0.1477)	-10.9%	
Year Three	1997-98	$1.2963	$1.1230	($0.1733)	-13.4%	($0.141)

Minnegasco

PBR Analysis

Customer Financial Impact

Year One

Total Incentive:	($4,347,528)	**Minnegasco's Incentive:****	$1,102,734
System Sales(in DT):	144,361,468	System Sales:	144,361,468
Per Unit Incentive:	($0.030)	Per Unit Incentive:	$0.008

Net Customer Incentive:	($3,244,794)	
System Sales:	144,361,468	
Per Unit Incentive:	($0.022)	

	Annual DT	Per Unit Reduction	Annual Incentive	Per Unit Increase	Annual Incentive	Per Unit Reduction	Annual Incentive
Residential	120	($0.030)	($4)	$0.008	$1	($0.022)	($3)
Commercial	650	($0.030)	($20)	$0.008	$5	($0.022)	($15)
Industrial	5400	($0.030)	($162)	$0.008	$43	($0.022)	($119)

Year Two

Total Incentive:	($10,580,605)	**Minnegasco's Incentive:****	$3,980,205
System Sales:	146,241,350	System Sales:	146,241,350
Per Unit Incentive:	($0.072)	Per Unit Incentive:	$0.027

Net Customer Incentive:	($6,600,400)
System Sales:	146,241,350
Per Unit Incentive:	($0.045)

	Annual DT	Per Unit Reduction	Annual Incentive	Per Unit Increase	Annual Incentive	Per Unit Reduction	Annual Incentive
Residential	120	($0.072)	($9)	$0.027	$3	($0.045)	($5)
Commercial	650	($0.072)	($47)	$0.027	$18	($0.045)	($29)
Industrial	5400	($0.072)	($389)	$0.027	$146	($0.045)	($243)

Year Three

Total Incentive:	($12,985,733)	**Minnegasco's Incentive:****	$5,395,761
System Sales:	130,367,675	System Sales:	130,367,675
Per Unit Incentive:	($0.100)	Per Unit Incentive:	$0.041

Net Customer Incentive:	($7,589,972)
System Sales:	130,367,675
Per Unit Incentive:	($0.058)

	Annual DT	Per Unit Reduction	Annual Incentive	Per Unit Increase	Annual Incentive	Per Unit Reduction	Annual Incentive
Residential	120	($0.100)	($12)	$0.041	$5	($0.058)	($7)
Commercial	650	($0.100)	($65)	$0.041	$27	($0.058)	($38)
Industrial	5400	($0.100)	($540)	$0.041	$221	($0.058)	($319)

Total customer incentive for three years:

	Total Incentive	Minnegasco Incentive	Net Customer Incentive
Residential	($24)	$9	($15)
Commercial	($131)	$49	($82)
Industrial	($1,091)	$410	($681)

** The positive numbers shown under Minnegasco's incentive reflect that customers are surcharged through the PGA for recovery of Minnegasco's incentive.

Note: The Total Incentive column represents the performance compared to the benchmark during the Plan year. Minnegasco's Incentive was recovered from customers through the PGA through the annual true-up mechanism.

Attachment D

Minnegasco

PBR Analysis

Revenue Impact

Year One

Total Incentive	($4,347,528)
Minnegasco Incentive	$1,102,734
Customer Incentive	($3,244,794)
Minnegasco Revenue	$635,165,900
Impact on Revenue	-0.5%

Year Two

Total Incentive	($10,580,605)
Minnegasco Incentive	$3,980,205
Customer Incentive	($6,600,400)
Minnegasco Revenue	$739,901,100
Impact on Revenue	-0.9%

Year Three

Total Incentive	($12,985,733)
Minnegasco Incentive	$5,395,761
Customer Incentive	($7,589,972)
Minnegasco Revenue	$609,599,700
Impact on Revenue	-1.2%

Minnegasco

PBR Evaluation

Summary of Major Demand Costs Reductions

A. TF12 Base and TF12 Variable Split

Year One	Year Two	Year Three	Total
($8,139)	($718,695)	($890,861)	($1,617,695)

B. Seasonal Reservation Fees

Year One	Year Two	Year Three	Total
($3,335,652)	($5,485,184)	($6,700,062)	($15,520,898)

C. Firm Field-Area Pipeline Capacity

Year One	Year Two	Year Three	Total

D. Pipeline Transportation Charges

Year One	Year Two	Year Three	Total

E. Capacity Release

	Year One	Year Two	Year Three	Total
Base	$2,172,636	$2,172,636	$2,172,636	$6,517,908
Actual	$2,668,901	$2,757,781	$2,805,716	$8,232,398
Savings	($496,265)	($585,145)	($633,080)	($1,714,490)

F. Efficient Use of Capacity

Year One	Year Two	Year Three	Total
($3,214,674)	($6,041,898)	($8,613,376)	($17,869,948)

Minnegasco

PBR Evaluation

Commodity Component Calculation - "Unit of Sale" method versus "Unit of Purchase" method

	Year One	Year Two	Year Three	Total
Unit of Sale Method	$4,605,130	$13,790,559	$8,539,083	$26,934,772
Unit of Purchase Method	$4,837,654	$8,520,015	$11,858,934	$25,216,603
Difference	($232,524)	$5,270,544	($3,319,851)	$1,718,169

Notes: The "Unit of Sale" method results are the actual results of the Commodity component of Model 2 (see Attachment B).
The "Unit of Purchase" results are taken from Attachment D, page 2, of each PBR filing.

Attachment G

Appendix B

Office of Attorney General-Residential Utilities Division
Comments

November 17, 1998

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Edward Garvey	Chair
Joel Jacobs	Commissioner
Marshall Johnson	Commissioner
LeRoy Koppendrayer	Commissioner
Gregory Scott	Commissioner

In the Matter of the Commission's Report to the Legislature on Minnegasco's Performance-Based Gas Purchasing Plan

MPUC Docket No. G-008/CI-98-1219

COMMENTS OF THE OFFICE OF ATTORNEY GENERAL

I. INTRODUCTION.

On November 2, 1998, ("Minnegasco" or "the Company") a division of NorAm Energy Company, and the Minnesota Department of Public Service ("DPS" or "Department") submitted a joint report to the Minnesota Public Utilities Commission ("Commission") regarding the Commission's Report to the Minnesota Legislature on Minnegasco's Performance Based Gas Purchasing Plan ("PBR Plan" or "the Plan"). The Report claims that the PBR Plan produced $27.9 million of lower gas costs compared to the benchmark which benefits both its consumers and Minnegasco to the tune of $17.4 million and $10.5 million respectively. Therefore, the Report indicates that the PBR Plan has been successful in lowering gas costs to Minnegasco's customers and the Commission should support the continuation of the gas purchasing PBR legislation which is to expire on January 1, 2000.

On November 3, 1998, the Commission issued a Notice of Comment Period asking interested parties to address the recommendations and conclusions of the Joint Report of Minnegasco and the Department. Specifically, the Commission requested comments on Minnegasco's performance under the Plan, including: (1) how Minnegasco's PBR Plan impacted customers' bills over time; (2) impact on utility revenues; and (3) effectiveness of the Plan in meeting the purposes contained in Minn. Stat. § 216B.167, subd. 1. In addition, the

Commission asked parties, if interested, to comment on the general effectiveness of Minn. Stat. § 216B.167; possible sunset of Minn. Stat. § 216B.167 on January 1, 2000; the absence of other PBR plans; or any other aspect of the statute. The Office of Attorney General, Residential and Small Business Utilities Division ("OAG") has reviewed the PBR Plan Report and files these comments.

The OAG notes that this is the only plan filed under Minn. Stat. § 216B.167 and, as such, must be evaluated carefully in order to determine whether Minnegasco's PBR Plan has achieved lower natural gas costs than would have been achieved absent the Plan. Therefore, in evaluating Minnegasco's PBR Plan, all aspects of Minnegasco's models, benchmarks and actual behavior must be analyzed in determining the success of the Plan. The OAG agrees with the report submitted by Minnegasco and the Department that under the evaluation process which was approved in the Plan, Minnegasco has out-performed the benchmarks. However, since this is the only PBR Plan authorized, the OAG has concerns with the models and benchmarks that were established in the Plan.

The Commission also had concerns with this PBR Plan due to the fact that in its March 12, 1998 Order Accepting Report and Approving Incentive Award, the Commission stated at page 5:

> Based on its analysis and the parties' comments the Commission would expect parties to give serious consideration to revising the benchmarks and/or the sharing mechanism based on the consistent results of the first two years of the plan.

The OAG agrees with the Commission analysis since the third-year results appear to be a continuation of the first two years of the Plan.

The Minnegasco/DPS comments start from the perspective that the Plan succeeded because Minnegasco beat the benchmarks. The OAG views success as a more complex issue. The key is whether the benchmarks were reasonable given Minnegasco's knowledge of efforts it could take to reduce gas costs. Based upon this review and an evaluation of the reasonableness of the benchmarks, it is not clear whether the Plan was successful in delivering ratepayer benefits or company windfalls. It is difficult to discern the Department's position on these issues as the joint report does not conduct a retrospective review of the measures. Objective critique of the Plan should not be avoided simply because the parties agreed to the benchmarks. Indeed, some of the OAG concerns stem directly from parts of the Plan we supported. A trial is intended to be an experiment from which all parties learn and improve. Unfortunately, the joint Minnegasco/DPS Report offers no comment on how to learn from the first Plan, even in light of the fact that they were unable to negotiate a continuation of the Plan. It is our hope that the analysis contained herein will assist the Commission in providing a more balanced report to the legislature.

II. SUMMARY OF PLAN RESULTS.

The OAG has reviewed the PBR Plan Report and provides the Commission with the following concerns regarding the Report. First, the Report indicates that the Plan gave Minnegasco the incentive needed to lower gas costs than Minnegasco would have had absent the Plan. However, the OAG notes that under Model 1, which is the local distribution company (LDC) component, Minnegasco under-performed the average of the other three LDCs during all three years of the Plan. Thus, the other LDC's customers (on average) received lower gas costs without providing their gas utility with a $10.5 million incentive to perform.[1]

Second, under the commodity component in Model 2, Minnegasco has shown that it could beat the benchmark in all three years of the Plan. However, in any future plans, other benchmarks may need to be analyzed to insure that the gas commodity costs for use in Minnesota are appropriate. Again, this is important since Minnegasco could not out-perform the other gas utilities in Minnesota. Thus, it is difficult to assess the relevance of the Model 2 benchmark given that non-incentive-based firms were delivering lower priced gas to their customers.

[1] This is significant since Minnegasco is the only gas utility under a PBR plan but cannot out-perform the average of the other three LDCs in Minnesota which are not under incentive plans.

Finally, in any future plans, if the same type of benchmarks are used, the demand component of Model 2 should be reset yearly. For instance, the demand component used by Minnegasco was based on a specific base year, namely 1994-1995. If Minnegasco beat the demand component in the first year of its Incentive Plan, that savings was carried over into the second year and each succeeding year of the Plan. Any renewed plan should take this into account and not allow demand costs savings for the first year to be carried over into succeeding years of the Incentive Plan.

In general, the OAG is concerned that companies possess the most information about their ability to reduce gas costs. Utilities seem eager to embrace plans where the benchmarks are relatively easy to achieve and to walk away from plans with more difficult measures. This casts a reasonable doubt on the claim that the Company took actions it would not otherwise have taken and suggests a need for a productivity offset as it is anticipated that some level of effort to reduce costs should occur on a regular basis.

III. OAG DISCUSSION OF PLAN RESULTS.

Minnegasco's PBR Plan contains two models upon which the reward or penalty is determined. Model 1 is the LDC component which compares Minnegasco's gas costs to that of the weighted average gas costs of the next three largest LDCs in Minnesota. Model 2 has a demand and commodity component. The demand component compares Minnegasco's incentive year demand costs with the demand costs in the base year of 1994-1995. The commodity component compares Minnegasco's commodity cost of gas to a "Inside FERC's" gas market report price listing at Ventura, Iowa with adjustments for fuel, transportation charges and lost and unaccounted-for gas on Minnegasco's system. The OAG will discuss each model and components contained in the models.

A. Model 1 -- LDC Benchmark.

Model 1 compares Minnegasco's average total unit cost of gas with that of Minnesota's next three largest LDCs[2] average total unit gas costs. Minnegasco under-performed the average of the other three LDCs by $26,319,420 for all three years of the Plan. See OAG Attachment A. However, the penalties related to the LDC benchmark were reduced to $14,538,827 due to the cap requirements of the Plan.[3] Absent the cap, Minnegasco would not have faired as well under the Plan and Minnegasco customers would not have rewarded Minnegasco $10.5 million for all three years of the PBR Incentive Plan, while Minnegasco was unable to out-perform the average of three other LDCs who did not have a gas purchasing incentive plan in place.

The OAG has performed an analysis on Model 1 to determine what the residential, commercial and industrial customers' savings would be for the average of the three LDCs over that of Minnegasco. As shown in OAG Attachment B, the savings above Minnegasco's gas costs would be $22, $119 and $981 for the residential, commercial and industrial customers, respectively, for all three years of the Plan. If the Minnegasco incentive amounts are added in each year, the savings above Minnegasco gas costs would jump to $31, $168 and $1,391 for the residential, commercial and industrial consumers, respectively. Minnegasco's performance under Model 1 was less than desirable when compared to the average of the other three LDCs in Minnesota.

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[2] The next three largest LDCs in Minnesota are Northern States Power (NSP), Peoples Natural Gas (Peoples) and Northern Minnesota Utilities (NMU).

[3] One concern that led the OAG to support this cap is that Minnegasco would benefit from poor performance of other utilities. It appears that this may have occurred in the last year of the Plan, with a significant increase in one of the three companies, and suggests why Minnegasco was able to narrow the gap.

B. Model 2 -- Demand Component.

The demand benchmark in Model 2 compares Minnegasco's base year demand costs (1994-1995 base year) to the demand costs of each of the next three years. Thus, if the base year demand costs are higher than the current year demand costs, Minnegasco receives a reward. However, if the base year demand costs are lower than the current year demand costs, Minnegasco faces a penalty. The OAG's review of this component of the PBR Plan has raised a concern; namely, does this reward result in a windfall to Minnegasco due to collection of a reward in a succeeding year for actions which were recognized in prior Minnegasco PBR years?

The OAG is concerned that the PBR Plan grants Minnegasco rewards for actions which were taken in prior years. An example may be appropriate here to show the OAG's concern. Assume Minnegasco has $100 million of demand cost in the base year. In the first year of the PBR Plan, Minnegasco reduces this demand cost to $90 million. Thus, Minnegasco's reward would be $10 million less any deadband or averaging included in the Plan. In the second year of the Plan, Minnegasco does not reduce demand costs but they continue at $90 million. Therefore, Minnegasco's second year reward would be $10 million less any deadband or averaging. Thus, Minnegasco would receive a reward in the second year of the Plan for actions which were taken in the prior year. This could be carried over for the term of the PBR Plan and would give Minnegasco a windfall for not reducing demand costs in succeeding years. This type of plan fails to require continued productivity gains or savings by the Company. In any new plan, procedures should be established to insure that a reward is not granted for actions that were taken in prior years and carried into the future. Plans should require companies to continually improve on purchasing behavior to obtain incentive rewards.

C. Model 2 -- Commodity Component.

The commodity benchmark in Model 2 compares Minnegasco's commodity cost of gas in each year to a "Inside FERC" Gas Market Report price listing at Ventura, Iowa. The price listing is adjusted for fuel, transportation charges and lost and unaccounted-for gas to get the gas from

Ventura, Iowa onto Minnegasco's system. Minnegasco claims that this would be an approximation of what Minnegasco's gas costs would be in the absence of a PBR plan.

The OAG has reviewed the commodity component of Minnegasco's PBR Plan. The OAG's review indicates that in the three prior years before the PBR Plan was introduced, Minnegasco's commodity cost of gas was slightly higher than that of the benchmark. Since the PBR Plan has been in effect, Minnegasco has lowered its gas costs to that which is below the benchmark. Thus, it appears that Minnegasco has lowered its gas costs to out-perform the commodity benchmark in all three years that the Plan was in effect. While the OAG has not performed an analysis on this, it appears that other LDCs in Minnesota may have beaten the commodity component in Model 2 of Minnegasco's PBR Plan. Thus, these LDCs appear to have done very well keeping gas costs low without an incentive program.

Thus, while it appears that Minnegasco may have taken action to reduce its commodity cost relative to the Ventura benchmarks, the key unanswered question is how that benchmark faired with respect to similarly situated LDCs. An analysis of the benchmark's relevance rather than its assumed rightfulness is required to determine the effectiveness of the Incentive Plan. While the Minnegasco/Department Report outlines steps taken by Minnegasco to reduce costs, the report fails to analyze why Minnegasco could not keep pace with gas costs of other LDCs. This information would be helpful in evaluating the overall effectiveness of the Plan.

IV. PLAN EVALUATION REQUIREMENTS.

The Commission, in its Notice of Comment Period, asked parties to address certain questions concerning Minnegasco's performance in its PBR Plan. The OAG will address these questions below:

A. Impact on customers' bills over time.

Minnegasco has shown that the actual results compared to the benchmarks in its PBR Plan has produced lower gas costs to its customers. The lower gas costs came from Model 2, which is the demand and commodity benchmarks of the Plan. However, Minnegasco could not out-perform Model 1 benchmark which was the average of the next three largest LDCs' gas costs in Minnesota. While the total PBR Plan had lower gas costs for Minnegasco customers, the three LDCs beat Minnegasco gas costs by $26.3 million, which would produce lower gas costs for the three LDCs' customers above that of Minnegasco. OAG Attachment B shows that if Minnegasco could have matched the average of the three LDCs' gas costs, the typical residential, commercial and industrial customers' gas bills would have been lower by $22, $119 and $981 respectively. This is an equally important measure, as these LDCs operated without incentive plans.

B. Impact on utility revenues.

The PBR Report states that the customers' incentive under the Plan exceeded $17 million, which reduced Minnegasco's revenues by less than 1% over the three years the Plan was in effect. The PBR Plan established a deadband area where no sharing or penalties occur between the benchmark and 0.5% of either side of the benchmark. Included in the over $17 million of customer incentives is $6.8 million of deadband. Thus, Minnegasco has included as customer incentives the dollar amount included in the deadband.

The OAG is not convinced it is accurate to characterize the $6.8 million included in the deadband as lower gas costs to consumers. The deadband was created to avoid penalties and rewards due to noise or impreciseness in the models. Thus, it is not clear that these amounts should be shown as savings in any legislative report. Certainly, if the Company had performed below the benchmark but within the deadband, there is no penalty to the Company. The deadband area is an obstacle which the utility must overcome before any reward or penalty to the utility occurs. This should be pointed out in the Legislative Report.

C. Effectiveness Of The Plan Meeting Subdivision 1 Of The Statute.

This is Minnesota's first and only PBR plan in existence. As such, the PBR Plan has provided the parties with valuable experience regarding the design of this plan. While the OAG has critiqued the various parts of the PBR Plan, the OAG believes that the Plan, as a whole, was a reasonable start at meeting the purpose of Subdivision 1 of Minn. Stat. § 216B.167. The OAG believes that changes would be needed to be made in order to insure that Minnegasco or another utility actually create clear incentives to lower their natural gas costs beyond that which may have been anticipated by the companies. Future plans should consider a productivity factor to assure that reasonable steps are taken on an ongoing basis to reduce costs before achieving incentive payments.

IV. CONCLUSION.

Based on the benchmarks of Minnegasco's PBR Plan. Minnegasco was successful in lowering its natural gas costs for its customers. These benchmarks were the first established in any incentive plan and the first three years experience provides inconclusive information that Minnegasco actually performed as well as it should have on behalf of its customers. Minnegasco was able to reap $10.5 million compared to the benchmark of natural gas cost savings it obtained over the three years of the Plan. Minnegasco's customers retained $10.6 million of savings outside the deadband.

The OAG believes that performance-based regulation plans are an alternative to traditional rate of return regulation. As such, if the PBR plans are designed appropriately, then utility customers may benefit. A well designed plan should not be easily achievable and should require continual effort in generating savings. The details of such plans are imprecise and thus it is difficult to measure how well the plan is working to change purchasing behavior. Thus, plan benchmarks should be set at a high level to insure that a windfall is not provided the utility for non-performance. This does not suggest that the utility should always be penalized. Rather it suggests that plans should be established so that when the utility outperforms benchmarks there is a sufficient degree of comfort that the company earned the incentive payments.

Dated: November 17, 1998

Respectfully submitted,

HUBERT H. HUMPHREY III
Attorney General
State of Minnesota

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AG:163105 v1

MINNEGASCO
PBR ANALYSIS

Model 1 -- LDC Benchmark

Year	Benchmark	Minnegasco	Difference	Dollar Difference	Cap Amount
1995-1996	$2.6943	$2.7814	$0.0871	$12,573,881	$6,022,890
1996-1997	$3.4603	$3.5493	$0.0890	$13,015,480	$7,785,878
1997-1998	$3.2937	$3.2993	$0.0056	$ 730,059	$ 730,059
TOTAL				$26,319,420	$14,538,827

LDC SAVINGS VERSUS MINNEGASCO SAVINGS
PBR ANALYSIS

Year One

Average LDC Savings Over Minnegasco	$ 12,573,881 [1/]
Minnegasco System Sales	$144,361,468[2/]
Per Unit Savings	$0.087

	Per Unit	Annual DT	Savings Year One
Residential	$0.087	130	$ 10
Commercial	$0.087	650	$ 57
Industrial	$0.087	5400	$470

Year Two

Average LDC Savings Over Minnegasco	$ 13,015,480[1/]
Minnegasco System Sales	$146,241,350[1/]
Per Unit Savings	$0.089

	Per Unit	Annual DT	Savings Year Two
Residential	$0.089	120	$ 11
Commecial	$0.089	650	$ 58
Industrial	$0.089	5400	$481

Year Three

Average LDC Savings Over Minnegasco	$ 730,059[1/]
Minnegasco System Sales	$130,367,675[2/]
Per Unit Savings	$0.0056

	Per Unit	Annual DT	Savings Year Three
Residential	$0.0056	120	$ 1
Commercial	$0.0056	650	$ 4
Industrial	$0.0056	5400	$30

Year	Residential	Commercial	Industrial
One	$10	$57	$470
Two	$11	$58	$481
Three	$ 1	$ 4	$ 30
TOTAL	$22	$119	$ 981
Minnegasco Incentive [2/]	$ 9	$ 49	$ 410
TOTAL	$31	$168	$1391

[1/] OAG Attachment A
[2/] Minnegasco Attachment D

Appendix C

Minnegasco/Department of Public Service
Reply Comments

November 30, 1998

MINNESOTA
DEPARTMENT OF
PUBLIC SERVICE

November 30, 1998

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 7th Place East
St. Paul, Minnesota 55101-2147

RE: In the Matter of the Commission's Report to the Legislature on Performance-Based Gas Purchasing Plans: Joint Comments of the Minnesota Department of Public Service and Minnegasco
Docket No. G008/CI-98-1219

Dear Mr. Haar:

The Department of Public Service (Department) and Minnegasco have reviewed the comments submitted by the Office of the Attorney General (OAG) on November 17, 1998. Enclosed you will find joint comments of the Department and Minnegasco in response to the OAG. The purpose of these joint comments is to simply note that the parties are in agreement on several points including whether the Commission's authority to approve Gas PBR Plans should be continued.

The Department and Minnegasco hope that these comments assist Commission Staff in their preparation of the Report to the Legislature on Performance-Based Gas Purchasing Plans. Please call either Douglas W. Peterson at (612) 321-4753 or me at (651) 296-0404 if there are any question regarding these comments.

Sincerely,

VINCENT C. CHAVEZ
STATISTICAL ANALYST
DEPARTMENT OF PUBLIC SERVICE

VCC/sm
Enclosure

Comments of Minnegasco and the Department of Public Service
In the Matter of the Commission Report to the Legislature on
Performance-Based Gas Purchasing Plans
Docket No. G-008/CI-98-1219

November 30, 1998

In Order to assist the Commission in the preparation of its report to the Legislature under Minn. Stat. §216B.167, Minnegasco and the Department of Public Service ("Department") jointly filed a summary and evaluation of Minnegasco's PBR Plan on November 2, 1998. On November 17, 1998, the Office of the Attorney General ("OAG") filed its comments in this matter.

The purpose of these short comments, submitted jointly by Minnegasco and the Department, is to simply note that the parties are in agreement on several points, including whether the Commission's authority to approve Gas PBR Plans should be continued. First, it should be remembered that Minnegasco's Plan originated from a collaborative process involving all interested stakeholders. The legislative authority evolved out of a Chair's Roundtable workgroup, was sponsored by the Commission, and supported as a consensus bill. The legislation unanimously passed both houses and was signed into law.

Similarly, Minnegasco's Plan also developed through a collaborative process, with Minnegasco, the Department, and the OAG jointly submitting a settlement agreement to the Commission. All parties made compromises in establishing the Plan's benchmarks. Ultimately, the three parties agreed to support the Plan as modified by the settlement, and the Commission subsequently approved the Plan. The OAG's role in the previous collaborative was beneficial to the process and we continue to appreciate their willingness to work on PBR-related issues.

Second, the OAG in its comments states that Minnegasco's Plan is "Minnesota's first and only PBR plan in existence. As such, the PBR plan has provided the parties with valuable experience regarding the design of this plan...the OAG believes that the plan, as a whole, was a reasonable start at meeting the purpose of Subdivision 1 of Minn. Stat. §216B.167." (OAG Comments, p. 8.) Minnegasco and the Department fully agree with these statements. The three years of actual operation under the Plan has provided us with valuable experience regarding the benchmarks used, the incentives they provided, and the actions undertaken. We agree that the Plan was a good first effort in using PBR in Minnesota. While the OAG did critique certain aspects of the Plan and parties may differ in how to interpret certain pieces of information, the fact is that a lot was learned through having the Plan. No one disagrees with the OAG that any future PBR plans would be revised to reflect this experience.

Finally, and perhaps most importantly, Minnegasco and the Department agree with the OAG that appropriately designed PBR plans have the potential to benefit customers and that the Commission should continue to have the authority to consider them. Both Minnegasco and the Department support the continuation of the Commission's PBR authority found in Minn. Stat. §216B.167. It is our understanding, based on the OAG's comments and in discussions with OAG representatives, that the OAG also supports the Commission retaining this authority.

Minnegasco and the Department appreciate this opportunity to comment and look forward to further assisting the workgroup in the development of the Commission's report.

Appendix D

Minn. Stat. § 216B.167 (1995)

Performance-based gas purchasing plan.

216B.167 Performance-based gas purchasing plan.

Subdivision 1. Plan approval; commission findings. A public utility that furnishes natural gas may petition the commission for approval of a performance-based gas purchasing plan under this section. The commission may approve a plan if it finds that:

(1) the plan provides incentives for the utility to achieve lower natural gas costs than would have been achieved in the absence of the plan, as measured by the benchmarks established in clause (3), by linking financial rewards and penalties to natural gas costs;

(2) the potential benefits of the plan apply, at a minimum, to each customer class purchasing firm natural gas service from the utility;

(3) the plan establishes one or more benchmarks against which actual natural gas costs will be measured and the benchmarks reflect relevant market conditions and represent reasonable and achievable natural gas costs in Minnesota for the term of the plan; and

(4) the plan provides that the utility cannot curtail or interrupt service to any customer class purchasing firm natural gas service during the term of the plan except for causes outside the reasonable control of the utility or causes not directly related to the gas purchasing practices of the utility.

Subd. 2. Sharing mechanism. A plan must include a mechanism through which the utility shares with its customers the difference between actual natural gas costs and the plan's benchmark costs during the term of the plan. A plan must provide details of the sharing mechanism and may include an allowed level of costs above and below the benchmark before any sharing is to take place. The commission must determine an appropriate percentage of the difference between the benchmark and actual natural gas costs to be shared between customers and the utility. The sharing mechanism shall be implemented annually under section 216B.16, subdivision 7a. Financial rewards or penalties under the plan shall not be considered in the determination of the utility's revenue requirements in a general rate case pursuant to section 216B.16.

Subd. 3. Reliability of service. A plan must allow for the imposition of penalties if the standard for reliability of service established in subdivision 1, clause (4), is not met.

Subd. 4. Plan evaluation. A plan must include an evaluation process and mechanism that is reasonable and capable of supporting a full review of the utility's performance under the plan. The commission shall evaluate the various customer and utility impacts of a plan based on this evaluation process and mechanism, including the impact on customer bills over time, the impact on utility revenues, and the effectiveness of the plan in meeting the purposes contained in subdivision 1. The evaluation must occur within a reasonable time following the end of the plan.

Subd. 5. Annual report. The utility shall provide an annual report to the commission documenting its performance in meeting the requirements of the plan. Upon review of this report, the commission shall determine and approve rewards or penalties as provided in the plan.

Subd. 6. Adoption. A plan may be filed and approved within a miscellaneous tariff filing pursuant to section 216B.16. The commission may approve, reject, or modify the plan in a manner which meets the requirements of this section. An approved plan is effective for a period of not less than two years unless:

(1) the plan is withdrawn by the utility within 30 days of a final appealable order approving the plan; or

(2) the commission, after notice and hearing, rescinds or amends its order approving the plan.

Subd. 7. General evaluation. The commission must evaluate the effectiveness of all plans approved under this section and submit its findings to the legislature by January 1, 1999.

Subd. 8. Expiration. This section expires January 1, 2000. All plans must expire no later than December 31, 1999.

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STATE OF MINNESOTA)
)SS
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, Margie DeLaHunt, being first duly sworn, deposes and says:

That on the 3rd day of February, 1999 she served the attached

REPORT ON PERFORMANCE-BASED GAS PURCHASING PLANS, PURSUANT TO MINN. STAT. 216B.167, SUBD. 7 (1995).

MNPUC Docket Number: G-008/CI-98-1219

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

XX By inter-office mail

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

Commissioners
Carol Casebolt
Peter Brown
Ginny Zeller
Bob Harding
Mike Bull
Jerry Dasinger
Janet Gonzalez
Mark Oberlander
Megan Hertzler
Kathy Brengman - DPS
Jeff Oxley - OAG
Curt Nelson - OAG

Margie DeLaHunt

Subscribed and sworn to before me,

a notary public, this 4th day of

February, 1999.

Robin Benson
Notary Public

ROBIN J. BENSON
NOTARY PUBLIC - MINNESOTA
My Comm. Exp. Jan. 31, 2000

In the Matter of a Commission Report
to the Legislature on Performance-
Based Gas Purchasing Plans, pursuant
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