Stipulated Exhibit 1

Inventory Value Team Report

Joe Deters
Jeff Gabriel
Len Gilmore
Al Harms
John Madziarczyk
Paul McLean
Jeff Metz

Proposal to Restructure Ratemaking for Gas Costs

I. LIFO Inventory Opportunity

Nicor Gas values it's inventory on a LIFO (last-in first-out) basis. Under this method, the inventory consists of gas priced at historical prices from 1954 to 1996. At December 31, 1997, there was about 110 BCF of gas in inventory. The "top" 30% of our LIFO layers are priced at close to market value. The "bottom" 70% of our LIFO layers are priced significantly below market value. There is about 75 BCF of gas in these lower priced layers, with market value of about $100-200 million in excess of cost.

Due to unbundling, it is likely that we will liquidate some of our LIFO inventory and reduce or eliminate the low priced LIFO layers, thus "releasing" some of this value. Under our current rate structure, book value of gas inventory reductions would be included in the PGA. We considered various alternatives of both releasing this value and capturing this excess market value (discussed in Sections IV and V).

II. Recommendation

We recommend that the company "capture" the LIFO inventory value by filing and implementing a Gas Rate Performance Plan (GRPP) related to gas costs. We think the best way to release this value is to continue to unbundle our services to our customers (Customer Select) together with the use of 3rd parties (marketers). There is a critical need to act quickly with the inventory value issue since the pace of unbundling may cause us to start withdrawing the low-priced gas in two or three years. The GRPP meets the timing requirement in that the legislation is in place (unlike eliminating the PGA), the ICC staff has effectively supported the concept of a GRPP in the recent CILCO hearings, and a GRPP does not require a fundamental change in the way we conduct our business.

Our approach was to determine the best strategy to capture the value of the LIFO layers. We recognize that a GRPP may also serve as an interim step towards the establishment of customer choice, unbundling of services and potential elimination of regulated sales service and the PGA.

III. Analysis and Management of LIFO Inventory Layers

The LIFO layers, as they existed at December 31, 1997, can be stratified as follows:

Layer Years	BCF	Book/Tax Value ($mil)	Book/Tax $/MMBtu	Excess Market Value ($mil)*
1984 - 1996	34	$ 105	$3.09	$ (37)-(3)
1969 - 1973	46	$ 14	$ .30	$ 78 - 124
1954 - 1968	30	$ 9	$ .30	$ 51- 81
	110	$ 128		$ 93-203

* at $2.00 to $3.00 per MMBtu.

Exhibit 4 attached shows a more detailed layering of the Nicor Gas owned inventory at December 31, 1997. December 31 of each year is important because it is the date whereby quantities of gas are compared between years to determine if we have removed a LIFO layer or added a LIFO layer. Any reduction in the total inventory would first be valued at the price of the most recent layer(s), which in our case is 1996. Therefore, our inventory would have to be reduced by about 30% before we begin liquidating the low-priced layers.

IV. Ways to Release Inventory Value

Customer Select:

One of the ways Nicor Gas can release the value of its inventory, market price less historical cost, is by expanding the Customer Select program. Expansion of Customer Select would allocate storage assets to participating suppliers in the program. Suppliers would replace Nicor Gas' inventory with their own inventory. This is not a new concept. Suppliers have been replacing Nicor Gas' inventory since the beginning of transportation in 1986. As inventory is replaced by suppliers, any gains or losses from historical cost levels have flowed through the Gas Supply Cost (GSC). Up to this point, the replacement of inventory by suppliers has not yielded significant gains or losses as company owned layers of natural gas being replaced by supplier owned gas have been priced at close to market value. As Nicor Gas dips further into its inventory layers, the gains from these older layers will be much more material. See the Analysis and Management of LIFO Inventory section of this report.

During the first year of the Customer Select program, over 20,000 customers signed up for the program. These customers use approximately 12 Bcf annually and their storage levels approximate 5 Bcf annually. Customer Select is being expanded during the second year to allow another 40,000 commercial and industrial customers to participate along with 80,000 residential and about 4,800 Rider 25 customers. Estimates are that company owned storage levels may drop by an additional 7-10 Bcf annually depending on customer acceptance of expansion of the program. Such reductions would be contingent upon the number of customers allowed to participate in the program and customer acceptance of transportation.

Release Storage to Marketers:

A third party or parties can be involved to release the value of the storage levels. This can be done in two ways. First, a third party (e.g. marketer) can replace the inventory during the injection cycle. Second, Nicor Gas can fill the storage during the injection cycle and then sell the inventory to a third party. Either way, Nicor Gas has withdrawn and sold the low cost inventories at market and will not be the holder of market price replacement inventories. Nicor Gas could contract with the third party for gas purchases out of the third party's inventory for its withdrawal requirements.

The principal advantage of using a third party is control over the rate of withdrawing the low cost layers and having the third party replace it. It could even be done in a single year or could be done over a number of years. Inventory replacement by a third party could also be used to supplement replacement by customers under Customer Select or other unbundling programs. For example, if only 70% of the available customers take advantage of Customer Select, then Nicor Gas could contract with a third party to fill the inventory to the desired level. A third party might also pay us to be able to fill our storage, depending on the market. Use of a third party to refill storage might also be viewed as a deliberate scheme to add shareholder value, as opposed to strictly using Customer Select to refill the storage inventories after the low-cost inventories have been withdrawn.

V. Ways to Capture the LIFO Inventory Value

GRPP

Using a performance based program for gas costs is the recommended method for the Company to capture the value from the LIFO layer. As discussed below, a GRPP offers advantages as compared to the alternative methods of establishing a fixed gas cost, eliminating the PGA and outright sale of the storage inventory along the same line as selling real estate.

Fixed Gas Cost (Gas Cost in Base Rates):

Recent legislation enables LDCs to file for a fixed gas cost. Once filed, the Commission must issue an Order within 240 days of the filing. After receipt of the Order, the utility has seven days in which to accept or reject the Commission's Order. During five years following the date of the Commission's Order, a public utility company may not file to reinstate a PGA clause. However, during that five-year period, the Company may request a rate increase in the normal process - because of higher gas costs.

This method is similar to a GRPP with some significant differences. It is similar in that a prudence review should be either eliminated or significantly reduced. However, under this option, the PGA would be fixed for five years. Second, fixing the PGA does not provide for sharing. Any net losses would be borne by the utility, and all net gains would be to the benefit of the utility (although the utility could agree to share the gain). However, if experienced or forecasted losses under a fixed PGA are significant, the utility is permitted to request a change in its gas supply charge as part of a full rate case.

A fixed PGA does, in theory, allow a more opportunistic means of using hedging tools to lock in a gain than would be available under a GRPP. Under a GRPP, future gas prices are hedged when they are "acceptable"; there is no certainty the futures price will be lower than the performance benchmark price, which will be a function of a market price. With a fixed PGA, the "benchmark" is a known value. If future prices are below the fixed PGA (and that's a big if) a known "gain" can be locked-in. If future prices are greater than the fixed PGA, a decision can be deferred or a known loss can be locked in.

In summary, a fixed PGA has some advantage over a GRPP (mainly that the performance benchmark is a known quantity) and some disadvantage (the unlimited risks). We believe the risks outweigh the advantage due to the following:

1 *Limited Future/Forward Market*: The futures market has very little liquidity beyond 2 years. In addition, the cost of forward price gas begins to increase as the term of the contract increases. Therefore hedging (through the futures market or forward contracts) is practical for only a one to two year forward period.

  In addition, relative to the volume of gas purchased by Nicor Gas, the futures market has limited liquidity even in the near term. Nicor Gas' purchase volumes would be 15 to 20% of the open position futures contracts 6 to 12 months forward and an even greater portion of longer term activity. The price impact of Nicor Gas contracting for significant volumes of futures contracts or forward priced gas could be significant. Nicor Gas could attempt to hedge its future gas purchases via a gradual entry. However, it is not clear if this would be an effective means of avoiding market impacts.

2. *Volume Risk*: A volume risk exists whether gas prices move up or down. For instance, if our fixed price is 30¢, but market price is 40¢, it is likely that transportation customers would elect to return to sales service. This would necessitate increased gas purchases, at the current market rate (i.e. gas purchases in excess of the hedged volumes). This would result in a loss to Nicor Gas. A possible mitigation strategy is to limit transportation customers' ability to return to sales service, or to establish a separate, non-fixed PGA for such customers.

   Similarly, if our fixed gas price is 30¢, but market price is 20¢, it is likely that some customers would leave us to purchase gas at prevailing market rates. This could cause us to have hedged volumes in excess of those required to meet customer needs. These excess volumes may need to be sold on the open market, once again causing Nicor to suffer loss. It is doubtful that the commission would allow Nicor to prohibit customers from leaving us if they would ordinarily have that option as unbundling progresses.

3. *ICC Response:* Finally, the largest hurdle to freezing the PGA may be commission Staff opposition. In the CILCO case, Staff has claimed that freezing the PGA does not provide incentives to lower gas supply costs, as does a GRPP. It simply establishes an opportunity, if the fixed gas price is set high enough, for the utility to generate revenue with no particular effort.

As of today, the only Illinois utility filing to apply for a fixed gas cost has been CILCO. The Commission issued its order on September 18th. The order did not approve of CILCO's proposed rates. The order effectively called for NYMEX futures prices at or about the time of the order to be the basis for a refiling by CILCO. It should be noted that the staff effectively suggested that a GRPP based on market rates would be more appropriate than a fixed gas cost. MichCon and Consumers Energy as well as a few other LDCs outside of Illinois currently have fixed gas costs.

Eliminate PGA:

Another way for potential profit from gas sales is to have our gas costs unregulated, similar to the way marketers currently operate. This option has the benefit of significant profit potential while not attracting many of the risks associated with the fixed gas cost alternative. However, while this option may be where we ideally would like to go, it may be unrealistic within the next few years.

Legislation is currently not in place to allow for this option. Thus, a legislative effort, the success of which would be uncertain, would be needed. Assuming the legislative effort is successful, we would then have to file with the ICC, causing additional delay. From the Commission's view point, two things would have to happen for this alternative to be acceptable. First, the Company would have to open up its residential market to all marketers. Secondly, a viable competitive market would need to be developed by the various marketers. That is, the market could not be held or controlled by one or two major marketers. Once the residential market is open, it would probably be several years before the ICC could be convinced that a competitive market existed. Therefore, from the Commission's view point this is not an alternative that is available to the Company in the short term.

In addition to the Commission's concern to the full development of the market, there will be concerns from the Company's view point of still being required to have a regulated gas supply function as there is for electricity. A number of business issues need to be resolved before the Company could move into this position, such as, supplier of last resort, handling of credit customers, allocation of storage and pipeline transportation assets, and other business items. Other legislative authority would be needed in order for the Commission to deal with these issues. Legislative action is not preferred because of the risk of having to give up something in return, such as a revenue reduction. Further analysis of the competitive gas supply will occur as unbundling proceeds, and as gas legislation is instituted to encourage the development of unbundling.

Real Estate as an Analogy for Inventory Value:

Like land, top gas inventory is non-depreciable. Therefore, a possible means of capturing the below market value of the gas inventory could be a filing with the Commerce which argues that any revenue gained from such a sale should accrue to the benefit of the shareholders, not the ratepayer. In 1990, the Illinois Commerce Commission ruled that the revenue gained from Nicor Gas' land sales should not be amortized over a period of time for the purpose of preserving the effect of the sale (the revenue gain) for rate making purposes. The below-market valued base gas in inventory bears some, but not perfect, resemblance to land.

This potential means of releasing and capturing inventory value was considered a low risk approach with little possibility of success. It is low risk since we would be making a request to the Commission for specific authorization. It would have a low probability of being successful since storage inventory value is a function of gas costs, which is governed by the GSC.

VI. PBR Legislation and History

The Company in 1996 made an incentive based rate filing (PBR). In that filing the Company requested that it be allowed to more actively manage its PGA without a prudence review, so that it could create benefits for both the shareholders and the sales customers. Under the PBR, the Company established a benchmark for comparison of its purchased gas cost on an annual basis. Any savings below the benchmark would create benefits for both the shareholders and customers. Any cost above the benchmark would also be shared. The sharing was established as 50/50 for the first $30 million of profit or loss and 90% to the sales customer and 10% to the Company for amounts outside this range. The PBR was ultimately withdrawn in January of 1997. One of the sticking points during the process was the law which indicated that customers "*will benefit*" under the provisions of an incentive based plan. The Commission, in reviewing the Peoples Gas Light and Coke Company's proposed plan, felt that the "will benefit" was a mandatory finding that they had to achieve.

Effective in December of 1997, the State Legislature passed the electric deregulation law which includes two sections addressing alternative rate regulation - one relating to performance based rates and the other to fix the purchased gas cost. The law relating to these two items is attached as **Exhibit 1**.

With respect to performance based rates, the new law stipulates that the Commission needs to find that the program is *likely* to result in rates lower than otherwise would have been in effect under traditional rate of return regulation. This wording is different and easier to achieve than the mandatory "will benefit" section under the old law. Under the new legislation, the Commission may issue an Order no later than 270 days from the date of the filing. The Commission must specify in the Order reasons why the proposed program, if not accepted, does not meet the required criteria and has to identify appropriate modifications. The utility has fourteen days following the Order to either accept or reject the modified program. Thus, the new law appears to permit utilities to make filings without any obligation to accept the revised findings of the Commission. This eliminates one of the concerns the Company had as to whether we would be mandated to accept any modified program that the Commission would issue.

For any utility accepting such a performance based plan, the Commission is required to review the plan results two years after the program is first implemented. This review may take up to 9 months. In essence, the utility has approximately two years and nine months before a change could be ordered. If the Commission does order a program revision, the utility may elect to discontinue the program. The Commission can not otherwise direct the utility to revise a program except to insure system reliability. During the period of the program, the Company may file to revise the plan subject to Commission approval under the same constraints as the initial filing.

VII. GRPP Specifics

We are proposing a Gas Rate Performance Plan that is similar to, but not exactly the same as, the PBR program Nicor Gas filed for in 1996. Changes were made to address certain issues raised by staff and others in the original filing, and to eliminate certain performance risks.

Under this proposed Gas Rate Performance Plan (GRPP), Nicor Gas' total annual purchased gas costs ("Actual Gas Costs") would be compared against an annual gas cost benchmark ("Benchmark Gas Cost") that is market sensitive. The difference between Actual Gas Costs and the Benchmark Gas Cost would be shared equally between the Company and its customers until the difference reached $30 million. The amount of the difference in excess of $30 million would be allocated 90% to customers and 10% to the Company. Exhibit 2 outlines the proposed structure of the GRPP in terms of the calculation of the Benchmark Gas Cost and Actual Gas Costs.

Benchmark Gas Cost:

The Benchmark Gas Cost reflects published city-gate market index prices at the time of sale to the customer ("Market Index Cost"). The Market index Cost is then adjusted for the actual seasonal differential in gas prices of inventory injections and withdrawals ("Storage Credit Adjustment") and a fixed amount related to firm supply, firm transportation and purchased storage capacity ("Firm Deliverability Adjustment")

The Market Index Cost represents the annual gas cost that the Company would expect to incur if all gas supplies were purchased at prevailing Chicago city-gate market index prices at the time gas is delivered to customers. It is determined by multiplying Nicor Gas' sales deliveries on a monthly basis by a Market Index Price for that month, and adding together the resulting twelve monthly amounts.

The Storage Credit Adjustment is intended to recognize the annual benefit that results from the purchase of gas supplies during off-peak periods, when prices are typically lower, the injection of that gas into storage, and the withdrawal of those supplies to meet demand during peak periods, when prices are typically higher. Nicor Gas expects to receive no significant gain or loss through the GRPP from the Storage Credit Adjustment.

The Firm Deliverability Adjustment represents the level of fixed costs incurred by Nicor Gas on an annual basis to reserve firm supply, firm transportation and purchased storage in order to ensure the availability and reliability of gas supplies for its customers during peak periods. The Firm Deliverability Adjustment would remain fixed during the term of the GRPP.

Actual Gas Costs

Actual Gas Costs would consist of total recoverable costs for the year as calculated and filed under Nicor Gas' Rider 6 - Gas Supply Costs, adjusted for items not pertinent under a GRPP.

Exhibit 3 provides a comprehensive example of the application of the proposed GRPP using hypothetical annual data.

VIII. Risks and Mitigation

Regulatory Risk

First we must consider whether filing under a GRPP in 1999 would subject the Company to a rate case. While this concern is legitimate, there are several items that mitigate this risk. First, the ICC has been tied up with concerns over electric deregulation so now is a better time to approach the ICC with an alternative gas pricing mechanism than in a few years.

Under the new legislation which permits a GRPP, much of the regulatory risk has been eliminated in comparison to the Company's first GRPP filing. One of the concerns up front would be any modification that the Commission may institute in the program. The Company may not feel comfortable with the level established that it needs to meet. However, the new law makes it very clear that the public utility can turn down any modifications to the program and continue providing service under its existing tariff. The second regulatory risk would be that which occurs at the two year review. The Commission after two years may find that the utility needs to make modifications to continue with its GRPP. However, again the utility has the option of accepting or rejecting the modification proposed by the Commission. To reject those modifications would require elimination of the GRPP entirely. Regulatory risk also declines as part of a GRPP since the prudence review of the Company's existing gas supply purchases would be eliminated. Under a GRPP, the Company has incentive to purchase at the cheapest cost possible. The Commission Staff should not insist on maintaining their current level of annual prudence review as there is an incentive for the Company to do its very best because the shareholders will benefit or be penalized. Any review should be an accounting review to make sure that transactions are properly accounted for and the benefits are properly calculated. This eliminates the concern that gas cost could be found to be imprudent and eliminated from our recovery mechanism.

The last regulatory risk would be that of earning in excess of the Company's allowed rate of return. Under a GRPP it is possible that the Company could make additional dollars such that the Commission may want to review the Company's overall earnings. However, this should be able to be mitigated by properly managing the earnings under the GRPP. The Company should also be able to argue that the more money it makes under the GRPP mechanism, the more benefit is immediately being shared with the sales customers.

In summary, regulatory risk under the new Legislative Law that went into effect in 1997 has substantially reduced the Company's regulatory risk.

Role of Third Parties

Various third parties would be very interested in partnering with Nicor Gas to achieve success under a GRPP. Substantial progress was made to establish Clearinghouse (now Dynegy) as our asset alliance partner in conjuncture with our prior GRPP effort. These third parties are very willing to insulate Nicor against losses under a GRPP in return for a share of any upside. However, we would be assuming a credit risk with such third parties. This could be mitigated by monitoring and modifying the credit risk, based on size and financial viability of the third party.

GRPP Performance Risk

Inventory Credit:

The GRPP benchmark is based on the market price of gas at the time of delivery. The Storage Credit Adjustment in the GRPP formula is intended to recognize that some gas supplies are purchased in off-peak periods when prices are typically lower and to eliminate any benefit to Nicor Gas through the GRPP from this price arbitrage. Since the Storage Credit Adjustment is computed based on inventory withdrawals, its effect is to convert the value of our LIFO inventory from 1) the difference between the price at the time of delivery and book value to 2) the difference between the price at the time of current year purchases and book value. Therefore, we have reduced the potential value of LIFO inventory that can be captured via the GRPP formula. We have determined that this is a necessary and acceptable consequence to capture any of the inventory value. However, it highlights the need for prudent inventory management.

Transportation Costs

Pipeline transportation costs present risk relative to Nicor Gas' ability to meet a GRPP performance target, since these costs are included in the Firm Deliverability Adjustment which will remain fixed during the term of the GRPP. Nicor Gas' estimated 1998 fixed transportation and purchased storage costs (excluding take-or-pay and Order 636 GSR and Account 858 surcharges) are $144 million. The excluded surcharges amount to only $8 million in 1998, and will be essentially eliminated over the next year.

There are several factors which could increase transportation costs in future years. First, all of our pipeline contracts will expire prior to October 2000. If renewed at current contract levels and at maximum rates, Nicor's fixed pipeline costs would increase by $38 million. Second, maximum pipeline rates can increase through regulatory action. Northern has filed a rate increase and rate design request that is expected to be acted on by November 1999. If granted, this could increase our fixed costs by $9 million annually. In addition, although Natural and Tennessee have not filed a rate case, Natural may do so in March 1999, and Tennessee may do so in January 2001. Both requests may be substantial, given the potential level of capacity turn-back on each pipeline. Third, Nicor Gas continues to experience significant design growth (approximately 1.5% or 75,000 MMBtu/d annually). The cost of pipeline capacity to meet this growth could be $6 million annually. Over three years, the annual cost could be as high as $18 million. Thus in a worst case scenario, our transportation costs, before mitigating items, could increase by $65 million.

Several factors can act to mitigate the potential increase in pipeline transportation costs. First, the degree of unbundling should offset some of the load growth impact. Second, although we should expect the cost of services to increase significantly on Northern Natural and NGPL, we should be able to reduce our costs from Midwestern and Tennessee by $5 million if competitive alternatives such as Northern Border and Alliance Pipeline are built. Third, as an alternative to pipeline firm services, we will have the ability to switch to more city-gate firm services. Although we do not know that these services will be less costly, we will have several contracting options that may be less costly. Fourth, in the last GRPP filing, Nicor Gas proposed to establish the benchmark based on actual fixed pipeline costs adjusted by known near-term events. However, given the degree of uncertainty, it would be more appropriate to base the fixed pipeline costs on a true forecasted basis. This estimate would reflect the uncertainties noted above.

Other options may also be available. We could exclude pipeline capacity related fixed costs from the GRPP. We would argue that such costs are long-term in nature and largely regulated, and therefore not appropriate for a GRPP. However, excluding any part of recoverable gas supply costs would (1) focus all prudence review effort on these costs and (2) raise the potential claim that we were shifting costs from variable (GRPP) costs to fixed (PGA recoverable) costs. We could wait until contracts have been renegotiated. This would delay the GRPP implementation until mid-year 2000. Although all of our contracts do not expire until mid-year 2000, we could accelerate the negotiation of contracts so that the costs are known, or largely known, before the GRPP benchmark is set. Although this would mitigate the contract renewal risk, it would not address increased costs that could result from pipeline rate increases or peak day growth.

In addition, Nicor could attempt to reduce its fixed pipeline costs by reducing pipeline services, such as reducing upstream pipeline capacity or summer capacity. Although this would serve to reduce fixed pipeline costs, it would also reduce our supply purchasing flexibility and could increase the cost of gas purchases. Also, Nicor could elect to meet its transmission system growth needs through contracted services, such as Voyageur Pipeline, rather than by capital investment. Purchased services would be reflected in Actual Gas Costs in the GRPP formula.

Other Costs and Revenues

An additional cost to include in setting a benchmark is the supply reservation. It is forecasted that this cost will be $11.0 million in 1998 and $8.7 million in subsequent years given the same level of supply needs by Nicor Gas. Obviously, unbundling would reduce the costs to Nicor.

Revenues that lower the benchmark are capacity release revenues (includes buy-sells, linked purchases and sales) and storage management credits. Capacity release credits for 1998 are forecasted to be $9.5 million and 1998 credit from storage management will be about $5.2 million. Subsequent years should generate similar credits.

IX. Collateral Benefits

It should be noted that the following benefits will be realized if the inventory levels are reduced, independent of whether they are in conjunction with a GRPP.

Carrying Costs

A reduction in inventory levels brings with it a reduction in the cost of money to carry the inventory. Assuming inventory value can be reduced by $100 million, we could see a $5 million reduction in annual interest expense.

Cash Flow from Current Tax Deduction

To the extent inventory is reduced below current levels, sunk costs that were previously capitalized (i.e. the actual gas inventory) would be deducted. Therefore, we would get a cash flow benefit from the tax deduction, without a corresponding current out of pocket expense. For instance, lowering LIFO inventory by about 80 BCF would yield a current cash flow benefit of about $32 million.