NATIONAL ECONOMIC
RESEARCH ASSOCIATES
777 SOUTH FIGUEROA STREET, SUITE 4200
LOS ANGELES, CALIFORNIA 90017
TEL: *213.346.3000* FAX: *213.346.3030*
INTERNET: *http://www.nera.com*

n/e/r/a
Consulting Economists

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NORTHERN ILLINOIS GAS COMPANY D/B/A NICOR GAS COMPANY	: :	No. 04-_____
	:	
Proposed general increase in rates, and revisions to other terms and conditions of service.	:	

Direct Testimony of

DR. HETHIE S. PARMESANO, PH.D.

Vice President

National Economic Research Associates

On Behalf Of

Northern Illinois Gas Company

Nicor Gas Exhibit 13.0

Q. Please state your name and business address.

A. My name is Dr. Hethie S. Parmesano, Ph.D. My business address is 777 South Figueroa Street, Suite 4200, Los Angeles, California 90017.

Q. By whom are you employed and in what capacity?

A. I am a Vice President at National Economic Research Associates, Inc. (“NERA”).

Q. On whose behalf are you submitting direct testimony in this proceeding?

A. I am submitting testimony on behalf of Northern Illinois Gas Company (”Nicor Gas” or the “Company”).

Q. What are the purposes of your direct testimony in this proceeding?

A. My direct testimony has three overall purposes:

- To explain the relevance of marginal cost information in the design of natural gas delivery rates;
- To identify, present, and support a study that I prepared (with the assistance of colleagues at NERA acting under my direction and supervision) of Nicor Gas’ marginal costs of natural gas delivery service (the “marginal cost of service study” or “MCOSS”), a copy of which is attached hereto as Nicor Gas Exhibit 13.1; and
- To describe the implications of the marginal cost of service study results for the Company’s class revenue allocation and rate design, and to discuss the Company’s proposed class allocations and rate design.

Q. Please summarize the main points of your direct testimony.

A. Prices that Illinois consumers pay for natural gas service already reflect marginal costs to a significant extent, because the gas commodity charges are, to a large degree, market prices. However, pricing natural gas delivery service based on marginal cost will improve the economic efficiency of the gas decisions made by Illinois households and businesses, which in turn will promote social welfare, benefit ratepayers as a whole, and reduce inter-customer cross-subsidies. Thus, subject to appropriate consideration of other ratemaking objectives, I recommend that the Illinois Commerce Commission (the "ICC"):

- Move toward marginal cost-based class revenue allocations so that deviations from marginal cost prices can be minimized.
- Set the price for marginal deliveries as close as possible to marginal cost.
- Strive for overall prices for delivery that avoid biasing decisions regarding use of gas.
- Require delivery rate structures that reflect, to the extent feasible, the structure of marginal costs.

The marginal cost study that I prepared for Nicor Gas, with the assistance of colleagues under my direction and supervision, suggests the need for significant shifts in the way the base rate revenue requirement is allocated to customer classes. In particular, residential customers are paying well below their marginal cost of service. These customers are also paying less than their marginal cost revenues after adjusting them downward proportionally to close the small gap between the Company's total marginal cost revenues and proposed base rate revenue requirement. (This approach to closing the gap is called the "Equal Percentage of Marginal Cost" or "EPMC" approach.) The MCOSS results also suggest that efficiency would be enhanced by increasing residential customer charges, introducing a fixed charge per design-day demand to cover low-pressure distribution costs, using seasonal charges to recover high-pressure and storage costs, and moving tail block prices closer to marginal costs.

Finally, Nicor Gas' proposed rates take a significant step in the right direction in terms of moving towards efficient rate structures. For most classes, customer charges are set at or close to marginal cost and tail block charges are set at marginal cost, thereby providing to customers whose use is large enough to reach the tail block an efficient price signal for incremental use. Although Nicor Gas used EPMC revenues (computed after establishing the residential revenue requirement) as a starting point for non-residential class revenues, other important ratemaking constraints outlined by Al Harms

(Nicor Gas Ex. 17.0) resulted in class revenue allocations that make little progress toward an EPMC allocation.

Q. Besides the marginal cost of service study, which is attached hereto as Nicor Gas Exhibit 13.1, are you sponsoring any other attachments to your direct testimony?

A. Yes, a copy of my *curriculum vitae* is attached hereto as Nicor Gas Exhibit 13.2.

I. BACKGROUND AND QUALIFICATIONS

Q. Please describe your education and professional background.

A. My B.A. is from Colby College, where I majored in economics. I have M.A. and Ph.D. degrees in economics from Cornell University. Since 1980, I have worked for NERA, specializing in utility costing, pricing, strategic planning and regulatory reform. I have testified widely on these matters.

For more than two decades, I have taught seminars on marginal costing and rate design. Attendees include staffs of utilities and regulatory commissions, as well as occasional commissioners. I also participate regularly in the University of Florida Public Utility Research Center/World Bank International Training Program on Utility Regulation and Strategy. I present the sessions on electricity tariff design.

Since 1982, I have directed NERA's Marginal Cost Working Group, a utility group that is dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications.

I have been involved in planning for and implementation of energy sector restructuring and retail access in many jurisdictions around the world, including California, New York, Ohio, New Mexico, Maine, Illinois, Maryland, Massachusetts, Arizona, Oregon, Ontario, India, Brazil, Argentina, El Salvador, Mexico, Spain, Greece, Ireland, Kenya, Cambodia, Japan and the UK.

My *curriculum vitae*, Nicor Gas Exhibit 13.2, contains more details on my credentials.

Q. Have you previously testified before the ICC?

A. Yes. Below is a list of six cases in which I have testified before the ICC:

Rebuttal testimony before the Illinois Commerce Commission in Docket No. 99-0013 on behalf of Illinois Power Company related to the advisability of unbundling revenue cycle services; the appropriate basis for credits for these services, if unbundled; and the role of marginal costs in a world of retail access, February 10, 1999.

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission, Docket Nos. 94-0134 and 94-0223 on behalf of Illinois Power Company, August 1994, regarding Illinois Power's proposal for a tariff that would allow contracts to prevent residential, commercial and industrial electric customers from choosing an uneconomic municipal by-pass option.

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket No. 91-0335, February 25 and March 30, 1992, regarding marginal costing and marginal cost-based rates.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, Docket No. 89-0276, December 27, 1989 and January 29, 1990, regarding revenue treatment of the differential between regular and economic development rates.

Expert testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket No. 90-0006, December 8, 1989, regarding marginal cost rate design.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, in A. E. Staley Manufacturing Co. v. Illinois Power Company, Docket No. 86-0038, September 12, 1986, and November 25, 1986, regarding standby rates.

II. RATIONALE FOR THE USE OF MARGINAL COSTS AND MARGINAL COST PRINCIPLES IN RATE DESIGN

Q. You mentioned in your introduction that you intend to explain the relevance of marginal cost information in the design of gas delivery rates. What are the arguments for basing gas delivery rates on marginal cost?

A. There are three major arguments for basing utility rates on marginal cost:

1. Social welfare benefits;
2. Benefits to ratepayers as a whole; and
3. Limiting / reducing cross-subsidies among ratepayers.

Q. What are the social welfare benefits for basing utility rates on marginal cost?

A. Economists agree that marginal cost pricing results in an efficient allocation of resources. Briefly, the theoretical argument is: *Marginal cost* is the cost of the resources needed to produce the next or last small increment of output. It represents the value of those resources in their next best alternative use. On the other hand, *price* represents the personal value, to the consumer, of the next or last small unit consumed. It is an indication of the amount of alternative consumption willingly foregone to consume the unit in question.

When price is equal to marginal cost, the cost of the next or last unit exactly matches the value of that unit to the consumer, and resource allocation is socially optimal. The resources used to produce the unit cannot be used for another purpose and produce greater consumer satisfaction. If price is below marginal cost, consumers will continue to buy additional units when the satisfaction they receive is below the cost of supplying the additional units. Resources are used up that would have produced greater satisfaction if used to produce something else. If price is above marginal cost, consumers artificially constrain their use of the good or service. Benefits they would have enjoyed from consuming more, at a resource cost lower than the value of those benefits, are foregone.

The provision of accurate economic signals to consumers requires taking marginal costs into consideration. Utility rates that reflect the marginal cost of service signal to consumers the cost of their consumption decisions. A consumer deciding what type of appliance to buy or how much to use existing energy-using equipment will make socially efficient choices if the price paid for the additional (or saved) unit of gas or electricity service is equal to the marginal cost of supplying it.

Q. What are the benefits to ratepayers as a whole of basing utility rates on marginal cost?

A. Economically efficient consumption decisions by ratepayers who face marginal cost-based rates mean the utility can avoid unnecessary, costly expansion of the system, so average rates can be lower. For example, if the gas delivery system has to be sized to meet winter peak-day demands, but the price of gas delivery service is below marginal cost in the critical winter months, the utility will have to install more capacity than would be required to meet peak winter demands that would result from rates with higher winter delivery charges. The result will be higher than necessary revenue requirement and higher than necessary average rates.

Q. How does marginal cost pricing reduce or eliminate cross-subsidies?

A. Cross-subsidies arise when costs attributable to consumption by one customer or class of customers are recovered from another customer or class of customers. When utility rates are designed so that marginal use is priced at marginal cost, the revenue received by the utility when a customer uses more covers the additional costs incurred to provide the extra service. If price is below marginal cost, some of the additional costs must be borne by someone else—in the short-run by utility shareholders, and in the longer run by other consumers. If price is above marginal cost and a consumer reduces use, the utility loses more in revenues than it saves in costs. Again, someone else must make up the difference.

Q. What conditions in the gas industry and local gas distribution company (“LDC”) business especially warrant use of marginal cost pricing?

A. Households and businesses can choose from an array of energy types for particular end-uses, and they can bypass gas service altogether if the price is too high. This means that the price of gas service matters a great deal and marginal cost pricing of gas service is particularly important. Furthermore, because gas supply and gas delivery are now unbundled services, consistent pricing of both is important.

Q. What is the connection between the cost basis for gas *delivery service* charges and the cost basis for the *commodity portion* of a customer's bill, which is just a pass-through of gas supply costs?

A. The cost of gas service to consumers is made up of two parts—the commodity cost of gas supply (including pipeline transportation and purchased storage) and the cost of delivery (including distribution and customer costs) on the LDC's system. For a residential customer, the commodity cost is approximately 75% of the total bill. For a large industrial customer, the commodity cost is typically more than 80% of the bill.

The cost of gas supply, whether purchased from the LDC or from an alternative provider, reflects, to a large degree, market prices—the marginal cost of gas as determined in a competitive market. Nicor Gas, other LDCs and competitive suppliers purchase gas, transportation and storage on behalf of their customers through a combination of long-term contracts and spot purchases, which may or may not be combined with financial hedges, all with prices that reflect the market's expectation of spot prices (marginal cost) over the term of the transaction. This means that the gas supply portion of a Nicor Gas consumer's bill is largely a marginal cost price (although somewhat smoothed by the pass-through formula).

The cost of delivery is not determined in the marketplace, but rather through the regulatory process, because delivery is not a competitive service. Regulatory policies should ensure that pricing of delivery is consistent with the existing marginal cost/market pricing of gas supply. Obviously, consumers make energy decisions based on the total cost of using gas—both commodity (whether they purchase from Nicor Gas or an alternative supplier) and delivery components. When the commodity portion is a market/marginal cost price but the delivery portion is based on embedded costs or some arbitrary allocation and rate structure, the result is likely to be inefficient price signals to consumers.

Q. What is at stake if delivery rates are based on embedded costs rather than marginal costs?

A. Let me begin by stating that in designing delivery rates, the degree of competition among gas suppliers is *not* at stake. The charges for gas delivery service will not affect the competitiveness of the gas supply business, so long as consumers pay the same for delivery–whether they purchase gas from the LDC or an alternative supplier. (For some large customers located close to interstate pipelines, bypass of the local distribution system is a possibility, but these situations are typically handled by special anti-bypass contracts; e.g., Nicor Gas' Rate 17.) However, the pricing of delivery service *does* affect the total price of gas consumption, and therefore the amount that customers choose to use their existing gas-fired equipment and their choice of gas-fired equipment versus some other type.

To the extent that gas delivery service is priced above marginal cost, it will discourage efficient use of gas, resulting in loss of benefits from higher gas use (e.g., a warmer home) and encouraging consumers to shift to lower priced but less economically efficient energy sources and energy substitutes (e.g., insulation). Pricing delivery service above marginal cost could also contribute to business customers' decision to leave the service territory or the state.

To the extent that the price for incremental gas delivery service is below marginal cost, gas will be over-used, both in terms of over-investment in gas equipment and inefficiently extensive use of existing gas appliances.

The LDC's financial situation is also at stake. If delivery service is priced above marginal cost to some classes and below marginal cost to other classes, customers with cheap delivery service will tend to use increase consumption and customers with expensive delivery service will tend to cut back. So until the next rate case, the LDC will lose load that is paying more than marginal cost and add load that is paying less than marginal cost, reducing the utility's rate of return to below the allowed level. Similarly, if the delivery charges per therm exceed marginal costs that vary with the amount of gas delivered, the utility will fail to earn its allowed rate of return in a mild year when total therms delivered are below normal. When the customer charges are below marginal cost, the utility will not earn its allowed return if more new customers are added than were forecast, all other things being equal.

Q. Does pricing at marginal cost always produce the allowed revenue requirement?

A. No. The revenue requirement is largely a function of depreciation and return on investment made in the past, and test-year operating and maintenance expenses ("O&M"), taxes, and costs associated with obligations such as environmental remediation, low-income support and renewables programs. Marginal cost is an entirely different concept. Marginal costs consist only of costs that vary with level of service, and are forward-looking, not a function of past investment, although recent historical information is often used as one input in developing estimates of future marginal costs.

Q. If rates are based on marginal cost, what happens to the gap between marginal cost revenues and the allowed revenue requirement?

A. The gap must be apportioned among the customer classes, and one or more rate components must be adjusted away from marginal cost to produce the appropriate class revenue. This should be done in a way that minimizes distortions in consumption compared to what it would be if prices could be set equal to marginal cost.

III. NICOR GAS' MARGINAL COST OF GAS DELIVERY SERVICE

Q. What are the principles that should guide performance of a marginal cost study of gas delivery service?

A. There are three basic principles. First, a marginal cost study represents the going-forward costs associated with small changes in gas delivery service. The analyst must find answers to the question: how would costs change if the utility needed to supply a small increment (or decrement) of service? Just because the utility is not forecasting the addition of customers of a particular type does not mean that there is no marginal cost for those customers. In some cases, information about costs incurred in the recent past is the best available predictor of marginal costs; however, the goal is to estimate how costs will change with quantity of service in the future. In addition, because capacity is added in lumps, it is generally not possible to measure costs that result from very small changes in service, so a marginal cost study actually estimates incremental costs associated with discrete additions in service, rather than theoretically perfect marginal costs.

The second principle is that marginal costs are utility-specific. They depend upon the planning and operating policies of the utility under study, the characteristics of its service territory, its financial situation, and the laws and regulations that govern its actions. The results of the marginal cost study should reflect the constraints applicable to the particular utility.

The third principle is that a marginal cost study should analyze the cost drivers for each component of service—for example, the number of customers on the system, design-day demand, maximum daily contract demand or through-put—and compute unit marginal costs using these drivers as the units. This principle also implies that costs that vary with the timing of the assumed change in service should be time-differentiated.

Q. How does the study that you prepared follow the principles you have identified?

A. To quantify the marginal costs of gas delivery service one must ask and answer the question: What are the additional costs that would be incurred with changes in the amount of gas delivered and consumed at different times of the year and the size and number of customers served?

We estimated marginal costs by examining Nicor Gas' planning processes and specific plans to determine what drives new investment and purchase decisions and how changes in consumption affect system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made.

The marginal delivery cost elements that we have developed can be grouped in four main categories:

- **High-pressure main and regulator station costs**: High-pressure facilities (transmission and high-pressure distribution mains and regulator stations) are sized to accommodate demand in extreme winter weather–so-called design-day demand–and are upgraded periodically as demand grows. We analyzed marginal high-pressure facilities costs by dividing the cost of planned expenditures related to growth by the forecast growth in design-day demand triggering that investment. The annualized investment per design-day thousand cubic feet ("MCF") was assigned to seasons of the year based on the relative likelihood that demand growth in each season will require additional investment—i.e., based on each season's estimated relative probability of containing the peak day. Virtually all probability of peak day occurs in December - February, so these months were defined as the winter season. Because the relationship between billing determinants and design-day demand varies from class to class, the seasonal costs per MCF of design-day demand were converted to class-specific costs suitable for rate design using the ratio of design-day demand to normal-weather peak-day demand for each class. Then, for customers without peak-day metering, the costs were converted to cents per MCF of gas delivered in the defined winter period.

- **Local gas distribution facilities (low-pressure regulator station and main) costs per MCF of maximum daily contract demand**: These facilities are typically designed using engineering design standards that take into consideration the expected long-term maximum demands of customers that will use them–the amount of maximum daily delivery capacity that a customer would contract for if required to identify its long-term needs for local facilities. In short, the low-pressure distribution system is designed based on the sum of the implicit contract demands of the customers to be served, not specifically on the number of customers or their actual demands at any given moment. The costs of this portion of the system are marginal when the mains and regulator stations are installed, and if they are ever replaced, but generally do not vary with a customer's actual demands from month to month or year to year. Some of these costs are recovered up front through a customer contribution in aid of construction (which may be refunded later), but other costs are typically recovered over time through rates. Our estimate of marginal investment in these local facilities was computed as the weighted average of the cost of three sample configurations of facilities (net of upfront customer contributions), divided by estimates of the aggregate design-day demands (as a proxy for maximum daily contract demands) of the customers served by the sample installations. (One of the sample configurations is used so rarely that its weight is essentially zero.)

- **Marginal customer-related costs per customer**: These costs vary with the number of customers on the system and include meters, house regulators, relief valves and service laterals for customers of various types; and customer-related expenses (including meter O&M, meter-reading, billing, accounting, uncollectibles and miscellaneous customer services) for customers of various types. Typical marginal investment in meters, house regulators, relief valves and service laterals for each customer class was supplied by Nicor Gas. We used Nicor Gas' 2005 budget for customer-related expenses as a reasonable proxy for total marginal customer-related expenses, and applied class weighting factors from Nicor Gas' embedded cost of service study ("ECOSS") to estimate marginal customer-related expenses for each class.

- **Marginal storage costs per winter therm of use**: Although technically a gas supply function, the cost of storage on Nicor Gas' system is recovered in delivery charges rather than in the Gas Supply Cost. Because Nicor Gas' temporarily unused storage capacity is sold to large customers and alternative suppliers, the negotiated price for such transactions is the opportunity cost of using additional storage for

Nicor Gas' sales customers. To estimate this marginal cost we divided the expected revenues from "parking" storage (based on Nicor Enerchange's parking revenue projections for 2005-2006) by the park volume associated with these transactions. This cost represents the marginal cost associated with each unit of Storage Banking Service (SBS) capacity for all Nicor Gas customers. Because sales customers are not billed on the basis of SBS capacity, we converted this value to a marginal storage cost per Winter MCF delivered. To do that, we divided the annual amount of storage capacity required for these classes (based on 23 times the sum of their design day requirements) by total MCF delivered to them December through February.

Q. What are other key elements of the marginal costing methods?

A. Once we have determined the marginal investment in each type of plant, we apply an economic carrying charge to convert the investment into an annual equivalent. This is standard procedure in a marginal cost study. Key assumptions in the economic carrying charge calculation include: (1) the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), (2) the expected inflation rate for that type of plant, and (3) the average service life and patterns of failure ("Iowa curve") for that type of plant.

Estimates of marginal O&M expenses are added to the annualized plant costs. As with customer-related expenses, we relied on Nicor Gas' 2005 O&M budget as the basis for our estimates of marginal O&M, assuming that near-term average O&M levels are, in general, a reasonable proxy for marginal O&M. (Certain O&M accounts not expected to vary with the amount of plant were excluded: Account 851—System Control & Load Dispatching, Account 860—Rents (Transmission), Account 871—Distribution Load Dispatching, and Account 881—Rents (Distribution).)

As a utility adds plant and incurs additional O&M on that plant, certain overhead costs also increase. We estimated loaders for general plant and plant-related administrative and general ("A&G") expenses using regression analysis over ten years of historical Nicor Gas data. The coefficient of the explanatory variable indicates how these overheads change as the underlying investment and O&M expenses change. This approach gives an accurate estimate of the marginal plant-related overheads that need to be included in a comprehensive marginal cost study.

We found no systematic historic relationship between non-plant-related A&G accounts and total O&M. Therefore, we developed a non-plant-related A&G loader from the ratio of three types of expenses that clearly do vary with O&M (social security and unemployment taxes, office supplies and expenses, and employee pensions and benefits) to total O&M (less gas procurement and A&G expenses).

Q. What are the sources of information used in the marginal cost study?

A. The data we used in the marginal cost study were from the following sources:

- Nicor Gas' historical costs as filed with the ICC (e.g., ICC "Form 21");
- Nicor Gas' latest capital and expense budgets, including three samples of low-pressure distribution facilities projects and the characteristics of the consumers to be served from them;
- Nicor Gas' financial forecast (for capital structure and cost of equity);
- Estimates of the Company's long-term incremental cost of debt, developed by Nicor Gas witness Dr. Jeff Makholm.
- Nicor Gas' ECOSS filed in this case, including monthly billing determinants used to develop the annual values in the ECOSS;
- 2005 and 2006 Nicor Gas Hub Revenue Forecast (as of June 2004);
- 2003 Meter, Service, House Regulator purchase and installation costs by class and typical diameter of service provided by Nicor Gas;
- Nicor Gas monthly sendout reports for the period 1999 to 2003 (to analyze probability of peak);

- System design-day demands for the period 2004-2006, provided by Nicor Gas (to analyze expected load growth); and
- 2005 forecast of normal-weather peak-day therms by rate class.

These are, for the most part, the forecasts, engineering studies and plans that determine Nicor Gas' investment and expenses in the near future. Thus, the marginal cost study results are not based on conjecture, but rather on the same analyses that drive actual Company expenditures.

In developing estimates of marginal cost revenues, we relied on Nicor Gas' forecasts of test-year billing determinants.

Q. Please summarize the marginal cost study results and their implications for a marginal cost-based rate structure.

A. A detailed description of the methods used and results are provided in the marginal cost report, included with this testimony as Nicor Gas Exhibit 13.1. The marginal cost study provides unit marginal costs (see Schedules 27-30 of Nicor Gas Exhibit 13.1) that could be translated directly to a marginal cost-based rate structure: (1) the monthly marginal customer-related costs could become the basis for a fixed monthly customer charge; (2) the local facilities costs could be the basis for a facilities charge either per therm of design-day demand (as a proxy for maximum daily contract capacity), or a per-customer charge using the class average design-day demand for very homogeneous classes; (3) the high-pressure marginal costs could be the basis for a charge per winter therm delivered to customers without demand metering and a charge per winter monthly peak-day demand for customers with the required metering; and (4) the marginal storage cost could become a charge per winter therm delivered.

Q. Because the plant investment included in the marginal customer costs and marginal local facilities investment are sunk, as far as existing customers are concerned, why should a marginal cost-based rate for existing customers include these costs?

A. It is simply a matter of timing. The costs are marginal when the equipment is installed, and when it must be replaced. Utilities could charge individual customers the entire cost of these facilities at the time of installation (and whenever they need to be replaced); however, traditionally customers have been allowed to pay for them over time in their rates. The marginal cost estimates take into consideration the portion of costs charged up front through Nicor Gas' line extension policy. The remaining marginal customer-related and local facilities costs are appropriately recovered in rates. Furthermore, because the cost of these facilities does not vary with gas consumption, it is appropriate to recover this cost on a fixed monthly basis.

To treat these costs as not marginal would cause several problems. First, it would create a significant gap between marginal cost revenue and the revenue requirement. Allocating the gap on an EPMC basis would lead to cross-subsidies. Second, recovering all or a portion of the gap in a charge per MCF would distort the price signal for gas consumption and discourage what would otherwise be efficient gas use. Finally, for consistency, this approach would also require a change in line extension policy, to require that all consumers pay in a lump sum whenever these facilities are installed or replaced.

IV. IMPLICATIONS OF MARGINAL COST STUDY RESULTS FOR NICOR GAS' CLASS REVENUE ALLOCATION AND RATE DESIGN

Q. If the marginal costs developed in the MCOSS were used directly in the marginal cost-based rate structure you have just described, would Nicor Gas recover its requested base rate revenue requirement?

A. Before I answer, I would like to clarify my interpretation of "requested base rate revenue requirement" for purposes of revenue comparisons throughout my testimony. The Company is requesting an increase in the revenue recovered from standard delivery rates, as well as a shift of commodity-related uncollectibles expense from delivery charges to the Gas Supply Cost (Rider 6) and specific recovery of franchise gas costs from customers in the affected franchise areas (Rider 7). To facilitate comparisons to current base rates (which were set to include all uncollectibles) and to revenues from marginal costs (which treated all uncollectibles as marginal delivery costs) the proposed base rate revenue requirements used for my comparisons have the following characteristics:

- The commodity-related uncollectibles that Nicor Gas proposes to shift from base rates to Rider 6 are included (and were also included in the marginal cost estimates).
- Rider 7 revenues are included. These costs are not marginal and are, therefore, excluded from the marginal cost revenues.
- Revenues and marginal costs related to Rates 17, 19 and 21 are excluded, as these customers are charged on the basis of individually negotiated contracts, which are not at issue in this rate case. This excludes $11,169,000.
- Rider 25 revenues (administrative charges to customers who contract with Nicor Gas to transport gas) are included (and are also included in the marginal cost estimates).
- Riders 13 (Supplier Transportation Service) and 16 (Supplier Aggregation Service) revenues are excluded. These Riders include administrative transportation fees for services charged to Suppliers representing a group of customer accounts. This excludes $1,738,000.

Thus, Nicor Gas' base rate revenue requirement (before the proposed change relating to Rider 6) of $587,416,000, less $11,169,000, less $1,738,000, yields the base rate revenue requirement of $574,509,000 used in the marginal cost revenue and revenue requirement comparisons, and in the EPMC class revenue allocation exercise.

Nicor Gas would recover slightly too much base rate revenue (as defined above) if rates were set equal to the marginal costs developed in the MCOSS. The table below compares the marginal cost revenues and the base revenue requirements (as defined above). The class marginal cost revenue figures were computed by multiplying the unit marginal costs by the units (number of customer months, design-day demand, monthly peak demand, seasonal therms) for each class, and then summed. Total marginal cost revenues are about 2.5 percent above the proposed new delivery base rate revenue requirement (as defined above).

Marginal Cost Revenues Compared to Revenue Requirement

Total Marginal Cost Revenues	Total Revenue Requirement	Difference between Marginal Cost Revenues and Revenue Requirement	
(000$)	(000$)	(000$)	(%)
		(1)-(2)	(1)-(2)/((2)
(1)	(2)	(3)	(4)
588,812	**574,509**	**14,303**	**2.5%**

Q. If delivery rates are to be based on marginal cost, how should the marginal cost gap be handled?

A. Ideally for purposes of efficient price signals, and setting aside all other considerations, the delivery rate structure should mirror the structure of marginal costs and charges should be set at marginal cost. When there is a gap, it must be allocated to classes and the decision must be made about which rate components to adjust to meet the class revenue requirement.

Consumers—not classes—make consumption decisions. So the focus should be on the effect of adjustments on consumers. Adjustments to fixed charges cause less distortion in usage than adjustments to charges based on consumption, unless the required adjustments are so large that they affect location or outright rejection of an energy type.

After adjustment to fixed charges, the next best option for closing the revenue gap is to adjust the first block of charges levied on consumption. Bill impacts are a ratemaking consideration, but this issue is not related to economic efficiency. Equity is also a consideration, but again is not related to economic efficiency. For this reason, regulators often favor EPMC for allocating the gap to classes. However, use of EPMC may lead to uneconomic bypass, so this must be considered if the gap is large and positive (which is not the case for Nicor Gas).

In Nicor Gas' situation, the marginal cost revenue gap is fairly small (about 2.5%). If the gap is allocated to classes by a proportional discount on all classes' marginal customer costs, the new revenue requirements for each class are as shown in column (2) of the table below. If, instead, the gap is closed by reducing each class' marginal cost revenues by the same percentage (EPMC), the new class revenue allocations are as shown in column (3) below. Small customers are affected more than large customers if the gap is closed by a proportional reduction (or increase in the case where marginal cost revenues are below the revenue requirement) in marginal customer revenues because marginal customer costs are a larger share of total costs than for larger customers. For that reason, the EPMC approach is often viewed as more equitable. Because both methods produce similar results (as shown below), I have used the EPMC approach for the additional rate analysis I performed.

Alternative Marginal Cost-Based Class Revenue Allocations

		Total Marginal Cost Revenues	Class Revenue Requirements Adjusting only Customer Costs Proportionally	Class Revenue Requirements Using EPMC
		(thousand dollars)		
		(1)	(2)	(3)
RATE 1	Residential service	**450,505**	**438,263**	**439,562**
RATE 4/ 10/ 11	General Service	**100,577**	**98,778**	**98,134**
RATE 6	Large General Service	**81**	**81**	**80**
RATE 74/ 81	General Transportation Service	**25,380**	**25,142**	**24,763**
RATE 76/ 81	Large General Transportation Service	**8,109**	**8,090**	**7,912**
RATE 77	Large Volume General Transportation Service	**4,160**	**4,156**	**4,059**
TOTAL		**588,812**	**574,509**	**574,509**

Q. How does the efficient class revenue allocation that results from closing the revenue gap, using the EPMC method you have just described, compare to class revenues at current rates and class revenues proposed by Nicor in this case?

A. The table below compares these three sets of class base rate revenues, using Nicor Gas' proposed revised classes. (The class labels indicate the classes to be consolidated under that proposal.) To facilitate comparison with existing revenues, the proposed base rate revenues shown here include commodity-related uncollectibles (a portion of Rider 6), and Rider 7 and Rider 25 revenues. The residential class is currently paying well below its EPMC share of the base rate revenue requirement. All other classes are paying above their EPMC share. However, as Nicor witness Al Harms explains in his direct testimony (Nicor Gas Exhibit 17.0), the Company is taking a gradual approach toward increasing residential rates. As a result, the overall rate increase requires the other classes to pick up additional revenue that, under a purely EPMC allocation, would be recovered from residential customers. This means that the relationship between proposed revenues and EPMC revenues from non-residential classes worsens under Nicor's proposal.

Current and Proposed Revenues Compared to EPMC Revenues for Combined Rates

		Class revenues at current rates	Class revenue requirement using EPMC	Nicor's proposed class revenues	Current revenues as % of EPMC revenues	Nicor's proposed revenues as % of EPMC revenues	Class Revenue Increase Required by EPMC Approach	Class Revenue Increase at Nicor's proposed rates
		(thousand dollars)						
		(1)	(2)	(3)	(4)	(5)	[(4)-(1)/(1)] (6)	[(3)-(1)/(1)] (7)
RATE 1	Residential service	322,468	439,562	378,037	73%	86%	36%	17%
RATE 4/ 10/ 11	General Service	115,234	98,134	134,542	117%	137%	-15%	17%
RATE 6	Large General Service	219	80	274	275%	345%	-64%	25%
RATE 74/ 81	General Transportation	38,632	24,763	44,340	156%	179%	-36%	15%
RATE 76/ 81	Large General Transportation	9,082	7,912	10,342	115%	131%	-13%	14%
RATE 77	Large Volume General	5,525	4,059	6,976	136%	172%	-27%	26%
TOTAL		491,160	574,509	574,511	85%	100%	17%	17%

Q. Have you developed a set of marginal cost-based rates consistent with your efficient class revenue allocation?

A. Yes, I developed a set of illustrative seasonal rates that produce the class revenues resulting from an EPMC allocation of the marginal cost revenue gap (Col. 2 in the previous table). In this illustrative rate structure, I adjusted all marginal customer costs downward by the percentage necessary to close the gap. This leaves all other charges at marginal cost and would give customers the incentive to make efficient choices about gas use and appliance purchase. The resulting charges are shown in the table below.

Illustrative Efficient Rates - EPMC Class Allocations and Adjustments to Customer Costs Only

		ALL PRESSURES						LOW PRESSURE ONLY		
		Sales Customers	Transportation Customers					Low Pressure Facilities Charge		
Rate		Storage Cost Charge	Storage Banking Service (SBS) Monthly Charge	Cust. Charge Per Mo.	Seasonal Charges for H-P Main and Regulator Station			per Design Day Therm (eq. MDCQ)		per Avg. Cust.
		(cents/therm supplied)	(cents/therm of storage capacity)	($/ mo.)	(cents per Therm)	OR	(cents/therm of maximum monthly demand)	(cents per Design day therm)	OR	($ per cust. per mo)
		Dec to Feb	Jan - Dec		Dec to Feb					
1	Residential service	1.35	-	12.80	3.84			23.06		3.62
4/10/11	General Service	1.35	-		3.49			23.06		
	4A/10A/11A			12.29						4.40
	4B/10B/11B			39.99						26.05
	4C/11C			77.21						344.35
6	Large General Service	1.35	-	161.12	1.21			23.06		889.49
74/81	General Transportation Service	-	0.19		3.49			23.06		
	74A			11.61						17.41
	74B/81B			47.70						77.64
	74C/81C			80.00						433.42
76/81	Large General Transportation Service	-	0.19	203.38	0.89			23.06		2,190.79
77	Large Volume General Transportation Service	-	0.19	116.64	0.92		18.95	23.06		13,546.63

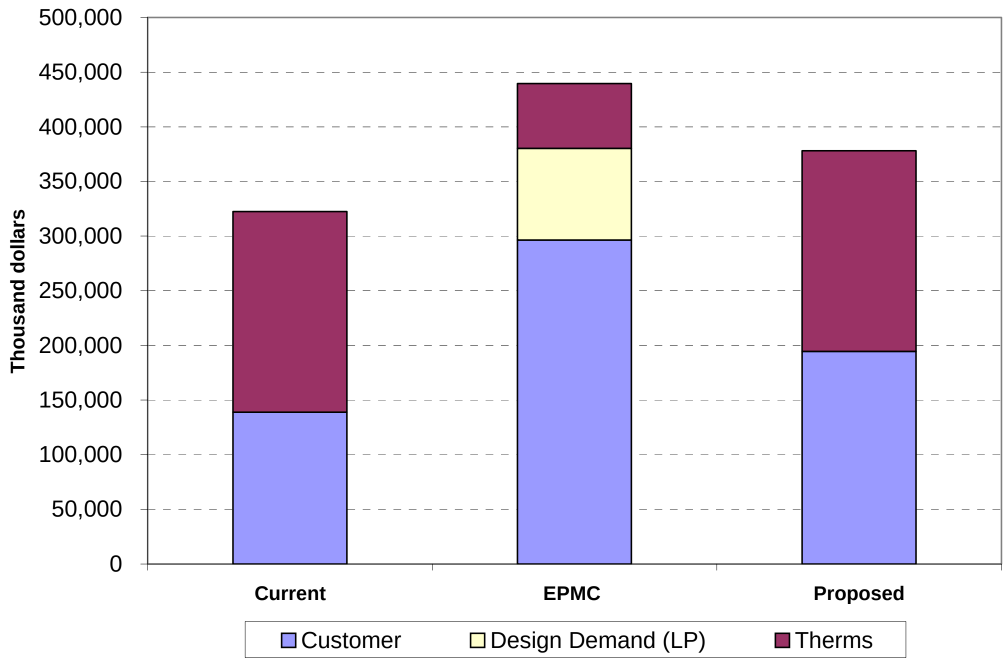
Q. How do the efficient rate structures that result from closing the revenue gap, using the EPMC method with adjustments only to customer costs, compare to the rate structures implicit in current rates and Nicor Gas' proposed rates?

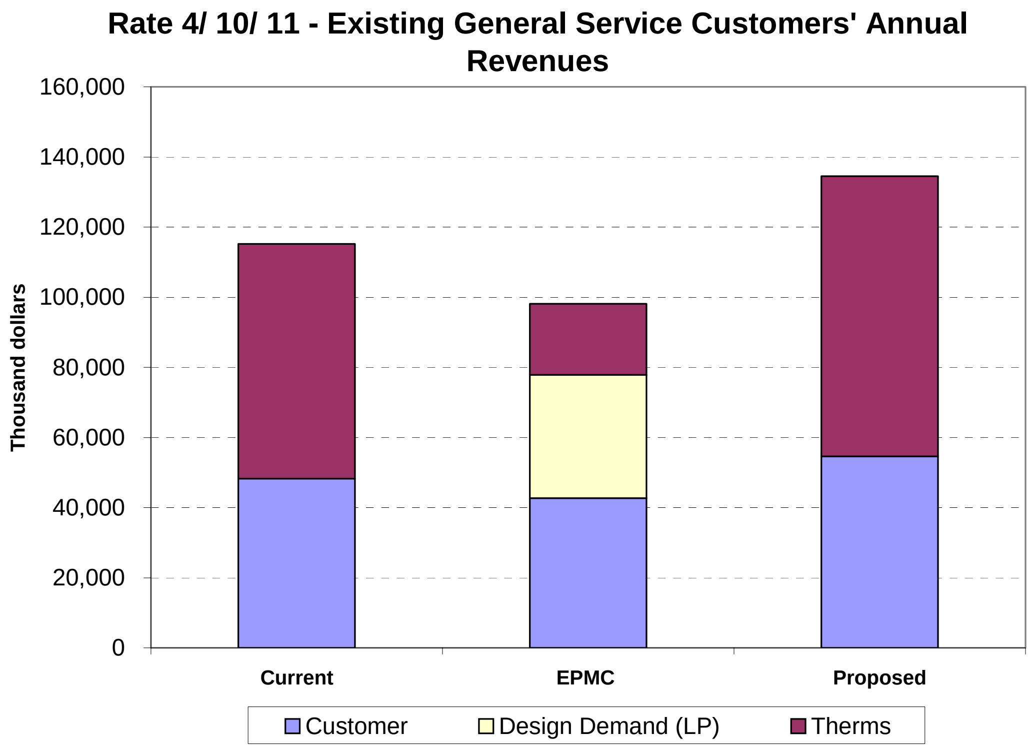
A. One way to evaluate the efficiency of the proposed rate structures is to compare the size of annual class revenues by component under current rates, efficient rates based on EPMC with only marginal customer costs adjusted downward, and Nicor Gas' proposed rates. The charts below show these comparisons.

The portions of the EMPC revenues designated as per-customer and per-design-day demand costs constitute the revenues that, ideally, should be recovered in fixed monthly charges. Comparing the sum of these two components to the per-customer revenue under current and proposed rates shows whether the proposed rate design for a given class is moving closer to the efficient level in terms of fixed charges. The Company's proposed fixed charges move toward the efficient levels for all classes.

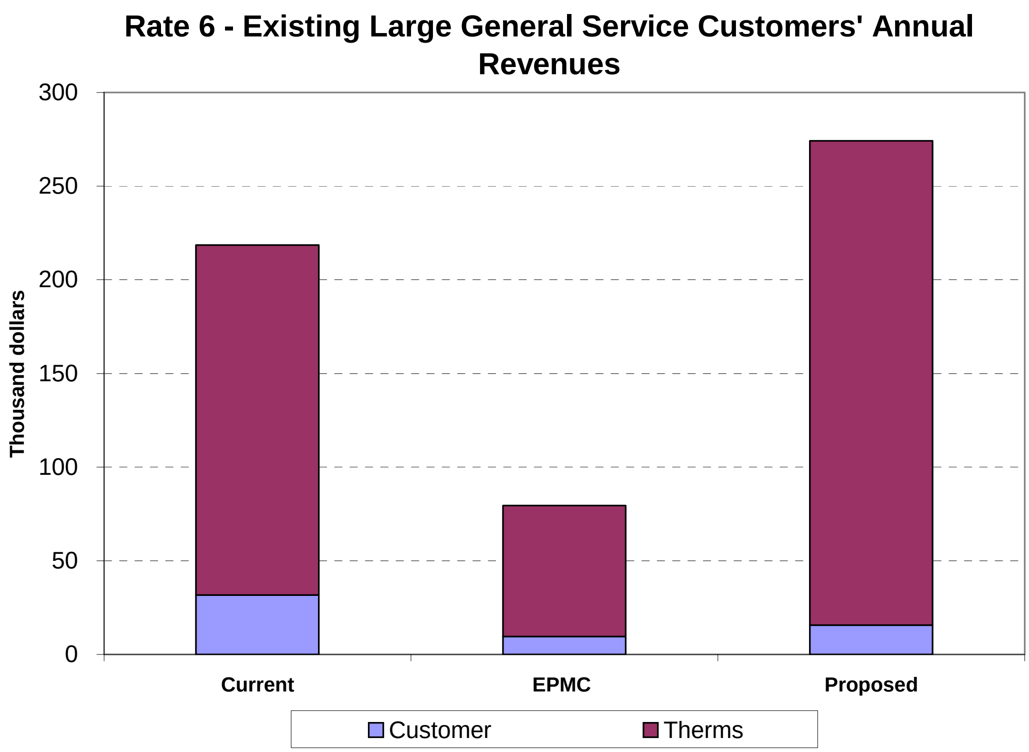
The charts also show that customers paying separate storage charges, Rates 74/81, 76/81 and 77, would face more efficient storage charges under Nicor Gas' proposal.

Rate 1 - Existing Residential Customers' Annual Revenues



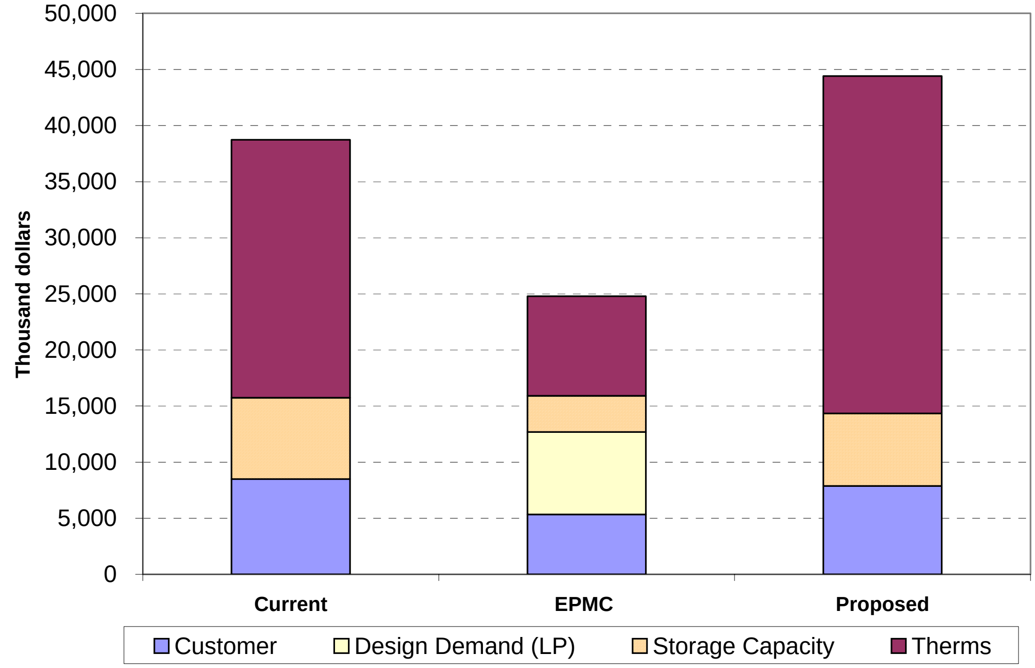

Rate 4/ 10/ 11 - Existing General Service Customers' Annual Revenues
Thousand dollars
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Current
EPMC
Proposed
Customer
Design Demand (LP)
Therms

538

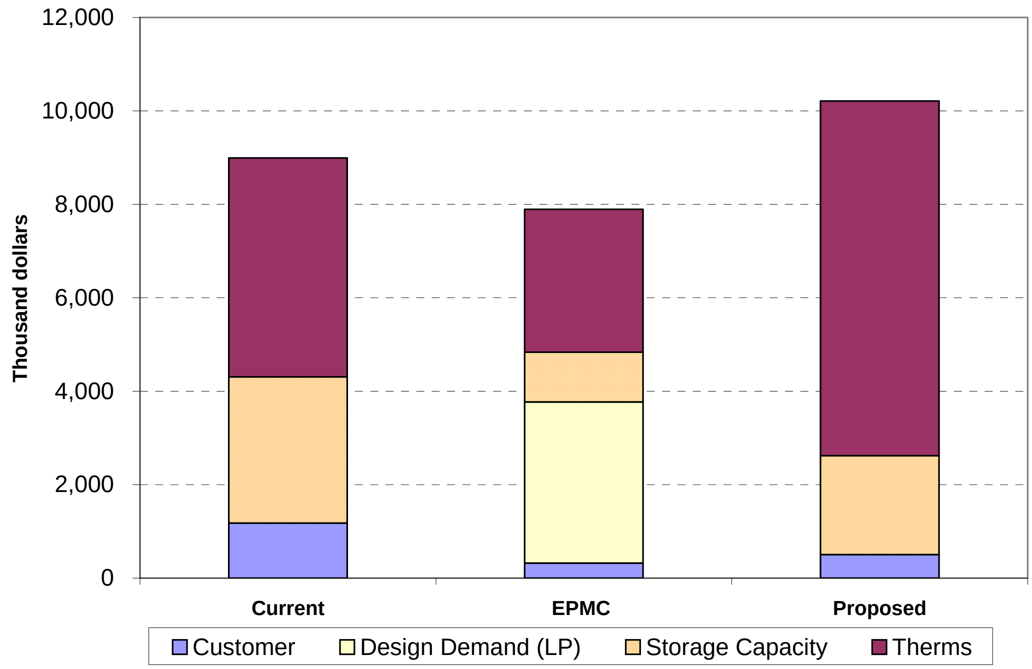

Rate 6 - Existing Large General Service Customers' Annual Revenues
Thousand dollars
300
250
200
150
100
50
0
Current
EPMC
Proposed
Customer
Therms

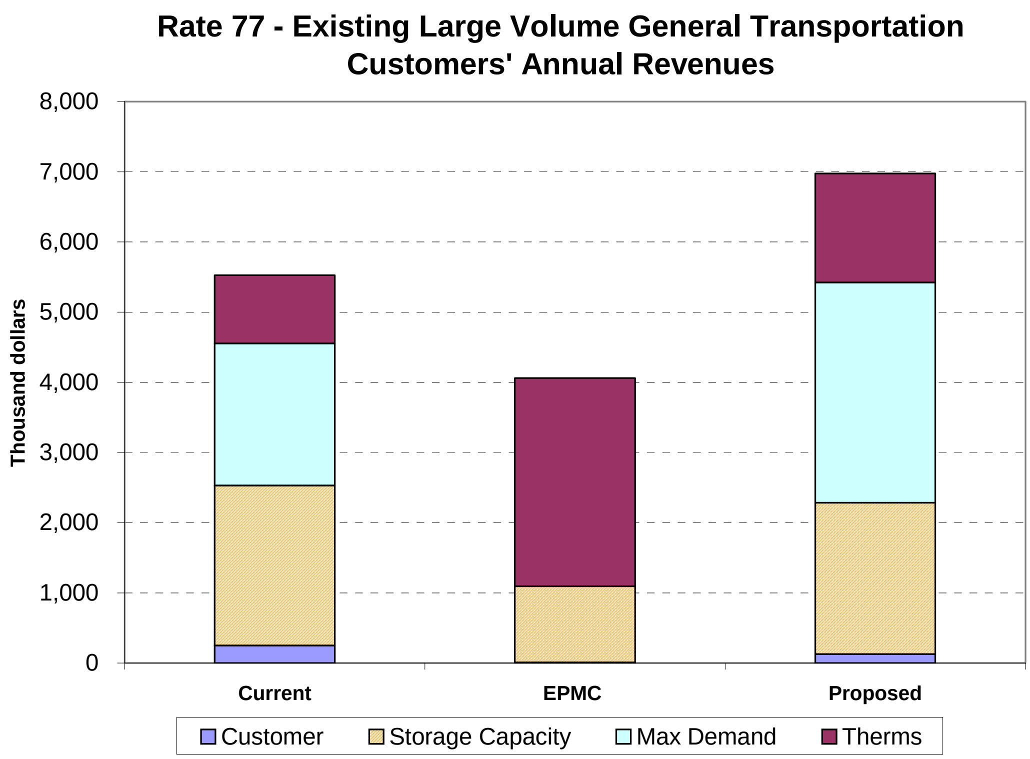
539

Rate 74/ 81- Existing General Transportation Service Customers' Annual Revenues



Rate 76/ 81 - Existing Large General Transportation Service Customers' Annual Revenues





Q. You have described how Nicor Gas' proposed rate structure moves toward more efficient fixed and storage charges for all classes. How do the proposed variable (per-therm consumed) charges compare to the pure marginal cost rate design (before any EPMC adjustments)?

A. The ideal rate design would include per-therm charges that vary by season – recovering high-pressure distribution and storage costs only in the winter. Nicor Gas is not proposing seasonal rates in this case. However, the Company has set the per-therm charges for final blocks of each rate with three blocks at the sum of winter high-pressure (or high-pressure plus storage, in the case of sales customers) marginal costs. These are the only delivery costs that vary with consumption of therms. Much of Nicor Gas customers' consumption that falls in the third blocks is winter use, which is likely to be much more elastic than summer use. Thus, this approach gives a marginal cost price signal for this most important segment of consumption. The fixed costs not recovered in proposed fixed charges (plus revenue associated with cross-subsidies to the residential class) are spread over the first two blocks. Rates 6, 76, and 77 are constrained by other ratemaking objectives outlined in the direct testimony of Nicor witness Al Harms, so their proposed variable charges are not set at marginal cost.[1] For all other rates, Nicor Gas' proposal takes a major step toward giving efficient price signals for marginal consumption.

The table below compares Nicor Gas' current rates and proposed rates with the corresponding pure marginal costs, expressed in the same form as the rates. The marginal costs per therm shown for the first and second blocks of consumption (for rates with multiple blocks) consist of high-pressure, low-pressure and storage (if applicable) marginal cost revenues for the year, less revenues from the tail-block prices that are set at winter marginal costs, divided by block 1 and 2 therms.

Comparison of Current Charges to Proposed Charges and Marginal Costs

	CUSTOMER			STORAGE BANKING SERVICE CAPACITY			DISTRIBUTION									
								Per Therm Delivered					Per Peak Day Therm			
	CURRENT	PROPOSED	MARGINAL	CURRENT	PROPOSED	MARGINAL		CURRENT	PROPOSED	MARGINAL			CURRENT	PROPOSED	MARGINAL	
	Customer Charges	Customer Charges	Customer Cost	SBS Charge	SBS Charge	SBS Cost		Distribution Charge	Distribution Charge	Cost			Demand Charge	Demand Charge	Cost	
	--------------------$/mo--------------------			---(cents/SBS therm/month)----				--------------(cents/Therm)-----------------					(cents/Peak Day Therm/month)			
							Block									
RATE 1	6.00	8.40	13.28				1	20.12	17.62	8.33	(A) HP+LP+ST					
							2	11.17	8.68	8.33	(A) HP+LP+ST					
							3	3.74	5.19	5.19	(W) HP+ST					
RATE 4 / 10 / 11							Block									
4a / 10a	11.50	15.50	13.41				1	13.30	14.86	5.23	(A) HP+LP+ST					
4b / 10b	50.00	50.00	41.11				2	6.83	8.39	5.23	(A) HP+LP+ST					
4c / 11c	100.00	100.00	78.33				3	3.77	4.82	4.82	(W) HP+ST					
RATE 6	450.00	200.00	194.11					2.07	2.98	1.21	(A) HP+ST					
RATE 74 / 81				0.39	0.38	0.19	Block									
74a	11.50	15.50	17.59				1	11.95	13.26	4.99	(A) HP+LP					
74b	50.00	50.00	53.68				2	5.48	6.79	4.99	(A) HP+LP					
74c / 81	100.00	100.00	85.98				3	2.41	3.49	3.49	(W) HP					
RATE 76 / 81	474.00	225.00	203.46	0.39	0.38	0.19		1.38	2.22	0.89	(A) HP+LP					
								"Commodity"				Block				
RATE 77	597.00	300.00	264.32	0.39	0.38	0.19		0.30	0.48	0.31	(A) 33% of HP	1	46.33	61.92		
												2	1.55	5.81	12.63	(A) 67% HP

Definitions: HP = High Pressure; LP = Low Pressure; ST = Storage; (A) = all months; (W) = winter months

[1] Proposed Rate 77 does include consideration of marginal cost. The tail demand block charge was set such that, at the average load factor for that rate, the revenues from the tail block demand charge plus the commodity charge for the equivalent use of therms would match the marginal cost revenues.

Q. Have you reviewed the Company's use of MCOSS results to set the tailblocks, as you have just described?

A. Yes. My staff and I have verified that the calculations have been done correctly.

Q. Does this complete your direct testimony?

A. Yes, it does.