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To this end, the United States Association for Energy Economics:

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- Fosters an improved understanding of energy economics and energy related issues by all interested parties.

Regulation of Gas Distributors with Declining Use per Customer

By Mark Newton Lowry, Lullit Getachew, and Steven Fenrick*

Many local gas distribution companies (LDCs) are today faced with the challenge of declining use per customer. The customer growth that chiefly drives the cost of distribution exceeds the volume growth that chiefly drives distribution base rate revenue. The result is a mismatch between cost and revenue growth that increases the need for rate escalation. This problem has been exacerbated by the recent high prices of gas in commodity markets.

While the financial impact of declining average use is easily demonstrated, regulators sometimes balk at the resulting rate hike requests. Their confusion is due in part to the marked variation in the problem across the energy utility industry. After all, some LDCs have in recent years experienced growing use per customer. This reduces their need for rate escalation and has sometimes permitted them to operate for extended periods without rate hikes. In the electric utility industry, rising use per customer is more the rule than the exception.

This paper explores some important dimensions of the declining average use phenomenon. We first use the logic of economic indexes to consider its theoretical impact on rates. There follow discussions of distribution cost drivers, declining average use, ballpark estimates of its rate and revenue impacts, and LDC rate design. Original research results are presented that draw on the authors many years of research on gas distribution cost.

Index Logic

The logic of economic indexes is widely recognized to yield results that are useful in utility rate regulation. One fundamental result of index logic is that the trend in the revenue of a utility is the sum of the trends in certain rate and output quantity indexes:

$$\text{trend Revenue} = \text{trend Rates} + \text{trend Output}^{\text{Revenue}} \qquad (1)$$

Here $\text{Output}^{\text{Revenue}}$ is an index of specific form that is designed to measure the effect of output growth on revenue. Growth in such an index is a weighted average of the growth in the utility's billing determinants. For a gas distributor, the salient determinants are variables such as the volume of gas delivered and the number of customers served. The weights for the index reflect the shares of each billing determinant in gas distribution revenue.

Suppose, now, that we are interested in the trend in a utility's rate that will ensure that growth in its revenue equals the growth in its cost:

$$\text{trend Revenue} = \text{trend Compensatory Cost.} \qquad (2)$$

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From [1] and [2], we know that this compensatory rate trend equals the distributor's unit cost trend.

$$\text{trend Rates}^{\text{Compensatory}} = \text{trend Compensatory Cost - trend Output}^{\text{Revenue}} \qquad (3)$$

The trend in the cost of a utility can be shown to decompose into the trends in appropriately specified indexes of the trends in its input prices, its total factor productivity (TFP), and in a different kind of output quantity index:[1]

$$\text{trend Cost} = \text{trend Input Prices - trend Productivity} + \text{trend Output}^{\text{Cost}} \qquad (4)$$

Here the trend in $\text{Output}^{\text{Cost}}$ is, like the trend in $\text{Output}^{\text{Revenue}}$, a wighted average of the growth in various output quantity measures. In this case, however, the weights reflect the impact of each quantity measure on *cost* rather than *revenue*. Specifically, each weight is the share of the corresponding cost elasticity in the sum of these elasticities.

Some readers may be unfamiliar with the concept of productivity. The growth in a productivity index is the difference between the growth in output and input quantity indexes.[2] A productivity index measures the impact on cost of a number of business conditions. These include technological change, the pace of capital replacement spending, and the realization of scale economies. Cost growth is slower the more rapid is productivity growth.

Our analysis leads to the following important result:

$$\text{trend Rates}^{\text{Compensatory}} = \text{trend Input Prices} - \text{trend Productivity} + (\text{trend Output}^{\text{Cost}} - \text{trend Output}^{\text{Revenue}}). \qquad (5)$$

It can be seen that the compensatory rate trend of a utility depends on three considerations. One is input price growth. Another is productivity growth. The third term is the difference between the trends in output quantity indexes that are calculated using cost- and revenue-based weights.

The third term helps to explain the volume per customer problem facing many LDCs. This term reflects the difference between the way that output growth affects cost and the way that it affects revenue. This difference depends on the extent to which rate design reflects cost causation. It can be shown that if distribution rate design reflects the sensitivity of cost to output growth, this term will have a negligible influence on the compensatory rate trend. We will therefore call this term the rate design effect.

The rate design effect also depends on the extent to which the output quantity variables used in the construction of the output quantity indexes grow at different rates. Suppose, for example, that delivery volumes and the number of customers grow at similar rates so that volumes per customer are stable. It doesn't matter in this case whether rate designs reflect cost causation. If, on the other hand, rates are not cost causative and there are noteworthy trends in average use, the effect on the compensatory rate trend can be substantial.

Revenue and Cost Effects of Output Growth

With this motivation, let us now consider what is known about the rate designs of LDCs. Most gas distribution revenue is drawn from rate elements that are either volumetric or from elements, like maximum demand, that are related to delivery volumes. A smaller but still important amount is typically drawn from customer or access charges. Revenue is thus particularly sensitive to growth in delivery volumes, but is also influenced by customer growth.

Consider, next, what is known about the drivers of gas distribution cost. PEG personnel have done extensive econometric research on this issue. Table 1 presents some results from a recent version of our long run econometric model of total gas distribution cost. The results are based on a sample of data from 42 LDCs in the United States over the 1993-2000 sample periods.

The chief source of the data is the Federal Energy Regulatory Commission (FERC) Form 2. The cost of capital is calculated using a perpetual inventory formula and plant addition data for a period dating back to the mid 1980s. The table reports the estimated long run marginal costs of customer and volume growth at sample mean values of the input prices, output quantities, and other cost drivers in the year 2000. It also reports estimates of the corresponding cost elasticities. The elasticity of cost with respect to total throughput, for example, is the percentage change in the total cost of distribution that results from 1% growth in total throughput.

Inspecting the results, it can be seen that the elasticity of cost with respect to growth in the number of customers served is substantially higher in the long run than that with respect to growth in throughput. It is also interesting to note that under sample average operating conditions, the marginal cost of customer growth is estimated to have been \$ 229 in the year 2000. This amounted to about \$ 19 per month and was well above the typical customer charge in the U.S. gas distribution industry. The long run marginal cost of volume growth was about \$ 0.53 per mcf in the same year. If our marginal cost estimates had been used as the basis for the rates of the sampled distributors in 2000, we estimate that customer charges would have accounted for about 64% of their base rate revenue.

These results suggest that gas distribution cost is, in the long run, much more sensitive to growth in the number of customers served than to growth in throughput. This finding clearly contrasts with the way that output growth typically affects base rate revenue. It follows that the direction and magnitude of the rate design effect depends on the trends in use per customer. If average use is rising, for instance, the rate design effect is negative and the compensatory rate trend is slower. If average use is falling, however, the rate design effect is positive and the compensatory rate trend is faster.

Average Use Trends

Research by the American Gas Association has shown that many distributors have in recent years experienced declines in weather-adjusted average use by residential and commercial customers.[3] These trends have been due chiefly to the improved efficiency of furnaces, water heaters, and other gas-fired equipment. Better building insulation has been another major contributing factor.

Table 1: Drivers of Gas Distribution Cost

Explanatory Variables	Estimated Marginal Cost	Estimate Cost Elasticity
Number of Customers	\$ 228.85	0.52
Total Throughput	\$ 0.53	0.30
Labor Price	NA	0.19
Capital Price	NA	0.53
% of Line Miles made of Cast Iron	NA	-0.24
Frost Depth	NA	0.07
Number of Electric Customers	NA	-0.01
Earthquake Risk	NA	0.03
Trend	NA	- 0.00

NA = Not applicable

Other Results	
Adjusted R^2	.967
Sample Size	336
Sample Period	1993-2000
Number of Companies	42

The AGA has also found that the extent of decline in average use varies regionally. From 1997 to 2000, for example, residential use per customer declined most markedly in the Midwest and West. It increased in the Northeast due, chiefly, to increased saturation of the space heating market.

Since these reports were prepared, there has been significant growth in the price of natural gas in the U.S. market. Demand growth surpassed by high oil prices and increased use of natural gas in power generation has not been matched by growth in gas production capacity. High prices seem likely to persist for the foreseeable future and are expected to put further downward pressure on gas use per customer.

Rate and Revenue Impact

Our discussion thus far leads to the conclusion that declines in average gas use may materially increase the compensatory rate trends for some distributors. How important is the rate design effect? Using data from Form EIA 176, we estimated the effect for gas distribution in 47 states and the District of Columbia. The sample period was 1997-2002 and we normalized the residential and commercial volumes econometrically for fluctuations in local heating degree days.

As suggested by equation [5], our estimates of the compensatory rate and revenue trends required the specification of input price and productivity trends. We assumed 2% growth in input prices. The productivity trends were the average growth rates over the sample period in total factor productivity indexes for gas distribution that we calculated for LDCs.

Results of the state-level work can be found in Table 2. The weather-normalized trends in the residential and commercial volumes per customer are reported as well as the overall rate design effect.[4]

Inspecting the results, it can be seen that the average use problem varied considerably by region. The phenomenon was most pronounced in the southwestern states. There, we estimate that the rate design effect increased the need for rate escalation by about 2% annually on average. Arizona had the largest rate

Table 2:Declining Average Use of Natural Gas by State, 1997-2002				
	State	**Residential**	**Commercial**	**Rate Effect**
Northeast		**-0.97%**	**-0.49%**	**0.09%**
	Connecticut	0.17%	-0.53%	1.04%
	D.C.	-2.68%	0.81%	-0.28%
	Maine	N/A	N/A	N/A
	Maryland	-0.52%	4.68%	-1.05%
	Massachusetts	N/A	N/A	N/A
	New Hampshire	-1.19%	1.32%	0.08%
	New Jersey	-1.71%	-1.07%	0.63%
	New York	-0.17%	-0.03%	-0.99%
	Pennsylvania	-1.61%	-1.50%	0.68%
	Rhode Island	0.04%	-1.86%	-1.22%
	Vermont	-1.08%	-6.22%	1.95%
Southeast		-1.22%	0.01%	0.32%
	Delaware	-0.55%	0.03%	0.07%
	Florida	-1.67%	4.90%	-1.30%
	Georgia	-0.65%	-4.36%	1.02%
	North Carolina	-0.91%	0.78%	0.41%
	South Carolina	-0.77%	0.00%	0.89%
	Virginia	-2.23%	-0.81%	0.97%
	West Virginia	-1.71%	-0.50%	0.16%
North Central		**-1.67%**	**-1.93%**	**0.72%**
	Illinois	-1.49%	0.01%	0.49%
	Indiana	-2.02%	-0.29%	0.66%
	Iowa	-2.77%	-2.21%	0.98%
	Kansas	0.04%	-1.64%	0.07%
	Michigan	-1.43%	-2.80%	0.84%
	Minnesota	-0.97%	0.53%	0.05%
	Missouri	-2.10%	-2.20%	1.19%
	Nebraska	-2.91%	-5.26%	1.70%
	North Dakota	-1.22%	-1.12%	0.16%
	Ohio	-1.77%	-2.88%	0.95%
	South Dakota	-2.33%	-2.49%	0.98%
	Wisconsin	-1.11%	-2.78%	0.53%
South Central		**-1.44%**	**-1.34%**	**1.18%**
	Alabama	-0.66%	-4.53%	2.34%
	Arkansas	-2.01%	1.30%	-0.03%
	Kentucky	-2.13%	-1.87%	1.32%
	Louisiana	-1.02%	0.02%	-0.26%
	Mississippi	-0.94%	-1.78%	2.82%
	Oklahoma	-1.61%	-0.10%	0.88%
	Tennessee	-0.49%	-2.41%	0.16%
	Texas	-2.70%	-1.40%	2.16%
Northwest		**-0.86%**	**-2.69%**	**0.31%**
	Idaho	0.07%	-0.33%	-0.63%
	Montana	-1.66%	-1.46%	0.76%
	Oregon	-0.95%	-1.17%	0.57%
	Washington	-1.19%	-2.85%	0.30%
	Wyoming	-0.54%	-7.63%	0.56%
Southwest		**-2.20%**	**-2.55%**	**2.01%**
	Arizona	-3.21%	-0.81%	4.26%
	California	-2.39%	-3.47%	1.85%
	Colorado	-0.87%	-2.32%	2.03%
	Nevada	-0.49%	-2.80%	1.56%
	New Mexico	-2.68%	-3.57%	1.13%
	Utah	-3.58%	-2.35%	1.23%
All States		**-1.53%**	**-1.35%**	**0.76%**

effect in both the region and the nation. The rate design effect also raised the average compensatory rate trend appreciably in the South Central and North Central states. The problem was least marked in the Northeast.

For the sampled states as a group, the normalized average use trends were a 1.53% annual decline for residential customers and a 1.35% decline for commercial customers. These declines are somewhat more marked than those reported by the AGA for the 1997-2000 period. They reflect in part the impact of a slowing national economy during this period.

The average rate design effect was estimated to be 0.76%. This means that the typical LDC needed rate escalation of almost 1% as compensation for the rate design effect. LDCs facing input price growth in excess of productivity growth would need additional compensation.

Policy Implications

Recent declines in the average use of gas have important implications for LDC regulation. Most obviously, regulators must be prepared to allow compensatory rate escalation for affected companies and recognize that other companies, which are not requesting rate relief, may face different business conditions. A number of regulatory strategies are available to obtain the needed relief. These include frequent rate cases, automatic rate adjustment mechanisms and the redesign of distribution rates. We discuss each of these options in turn.

Increased Rate Case Frequency

The rate case approach is a common response for LDCs operating under traditional cost of service regulation (COSR). For an LDC with declining average use, rate cases would be held more frequently. Distributors that have recently pursued this approach include Questar Gas (Salt Lake City, UT, USA) and Enbridge Gas Distribution (Toronto, ON, Canada). A noteworthy advantage of this approach is its feasibility. Efficiently managed utilities that are underearning are entitled to rate increases under traditional rate regulation.

On the downside, regulators may not be comfortable granting rate increases frequently. Some will be tempted to offset the growth in compensation for declining average use with unusually hard-nosed decisions on other rate case issues such as the allowed return on equity or the inclusion of employee bonuses in rates. Frequent rate cases weaken utility performance incentives by reducing the opportunities to profit from better performance between cases. They also discourage regulators from granting utilities operating flexibility because they continually raise awkward issues such as the fairness of affiliate transfer prices. Frequent rate cases are also costly. One of the biggest costs is the diversion of senior management from the basic business of providing quality service at a reasonable cost.

Alternative Regulation

The term alternative regulation (Altreg) is sometimes used to describe a variety of alternatives to COSR. These approaches often involve automatic rate adjustment mechanisms that permit rate cases to be held less frequently. This approach to regulation is especially common outside North America, but is also used to regulate many North American energy and telecom utilities.

General advantages of Altreg include a strengthening of performance incentives. LDCs can potentially earn superior returns for superior performance. Management can better concentrate on their basic business. The decoupling of rates from the distributor's own cost reduces concern about operating prudence and cross-subsidization and thereby makes it easier for regulators to grant LDCs greater operating flexibility.

On the downside, distributors will encounter resistance to Altreg in jurisdictions where cost of service regulation is well established. Another concern is regulatory risk. Lack of experience with Altreg may encourage regulators to choose important plan terms arbitrarily.

A variety of automatic rate adjustment mechanisms have been implemented that can be used to address declining average gas use. Of greatest interest, perhaps, are those that involve balancing accounts that operate to ensure that the revenue requirement is recovered. Any shortfall in recovery can result in a temporary rate adjustment to recover the shortfall next period. Mechanisms of this kind are sometimes called revenue decoupling mechanisms due to their ability to decouple revenue from sales volumes. This approach facilitates demand-side management initiatives.

An important challenge encountered in such revenue requirement regulation is that the need for distribution revenue typically grows over time due to such forces as input price inflation and customer growth. Mechanisms have been developed to increase the revenue requirement automatically to take account of these forces. These mechanisms often involve indexation.

A simple example of an index-based revenue decoupling mechanism is the revenue per customer freeze mechanism that currently applies to the gas distribution revenue of Baltimore Gas and Electric. Under this approach, the revenue requirement grows annually by the amount of customer growth. It can be shown that this produces a rate trend that roughly compensates a distributor for any decline in average use. However, it does not provide compensation for any amount by which a company's input price growth exceeds its TFP growth.

Another simple approach is to have the revenue requirement escalate by the inflation in a familiar macroeconomic price index such as the CPI. This approach has been approved in California for the gas distribution services of Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Gas. This approach provides automatic compensation for accelerating input price inflation but does not compensate for any tendency of customer growth to exceed productivity growth.

More complex and tailored revenue requirement indexes have also been implemented. Southern California Gas, for instance, operated for six years under a revenue per customer indexing plan. This effectively allowed the company's base rate revenue to grow by the inflation in an industry-specific input price index less the trend in gas distribution industry productivity plus the growth in the number of customers that the company served.

Mechanisms that index rates rather than revenue requirements can also be designed to accommodate declining average use. A typical price cap index has the formula P-X where P is an inflation measure and X, a term called the X factor, can slow

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the real growth in rates to the benefit of customers. In the face of declining average use, the X factor needs to reflect the rate design effect in [5] as well as expected productivity growth.

Rate Redesign

The third approach to mitigating the declining average use problem is to redesign base rates to make them more reflective of the drivers of gas distribution cost. For many LDCs, a redesign would involve an increase in customer charges and a decrease in volume-related charges. This approach can mitigate the rate design effect indirectly as well as directly. After all, lower volumetric charges would encourage greater gas use. Furthermore, the period between rate cases can be lengthened, thereby bolstering performance by strengthening incentives and facilitating greater operating flexibility.

The econometric research presented in this paper points the way to rate designs that are more cost causative. Specifically, customer and volume-related charges can be adjusted to be proportional to our estimates of the cost elasticities of customer and throughput growth. If the revenue produced by marginal cost based rates is inadequate, customer and volume-related charges can be increased proportionally to ensure that they are compensatory. Using this approach, our research suggests that more than half of the base margin would be obtained from customer charges but a sizable share would still be drawn from volume-related charges.

The redesign of rates can be introduced gradually to soften the impacts on specific customer groups. In a multiyear rate plan, for example, the growth in customer charges for households can be limited to a certain percentage per annum. Such restrictions have long been common in North American Altreg plans for telecom utilities.

Footnotes

[1] This discussion is drawn chiefly from theoretical results in a classic treatise by Denny, Fuss and Waverman (1981). A thorough discussion of the implication of index logic for regulation is found in Lowry and Kaufmann (2002).

[2] The TFP index in this discussion uses the cost-based output quantity index.

[3] See, for example, the AGA publications "Patterns in Residential Natural Gas Consumption Since 1980", EA 2000-01, February 2000; "Trends in the Commercial Natural Gas Market", EA 2002-04, October 2002; and "Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020, EA 2004-04, September 2004.

[4] Some deliveries to industrial and generation customers that are reflected in these numbers were not made by LDCs.

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