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UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION INCENTIVE PLAN ACCOUNT (IPA) AUDIT	)	**CONSOLIDATED DOCKET NOS. 01-00704 and 02-00850**
	)	
UNITED CITIES GAS COMPANY, a Division of ATMOS ENERGY CORPORATION, PETITION TO AMEND THE PERFORMANCE BASED RATEMAKING MECHANISM RIDER	)	

CONSUMER ADVOCATE AND PROTECTION DIVISION'S RESPONSE TO ATMOS ENERGY CORPORATION'S POST-TESTIMONY DISCOVERY REQUESTS

Comes now Paul G. Summers, Attorney General and Reporter for the State of Tennessee, through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), and hereby submits the following responses to Post-Testimonial Discovery Requests propounded by Atmos Energy Corporation's ("AEC").

GENERAL OBJECTIONS

1. The Consumer Advocate objects to the definitions and instructions contained in the data requests to the extent that the definitions and instructions attempt to impose on The Consumer Advocate a burden or obligation greater then that required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

2. The Consumer Advocate objects to the data requests to the extent they call for information and the production of documents which are protected from disclosure by the attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. In particular, the Consumer Advocate objects to requests seeking its legal research related to pertinent statutes, rules, orders and case law. The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's data requests to the extent they seek information relating to matters not at issue in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, The Consumer Advocate does not concede that such information is relevant, material or admissible in evidence. The Consumer Advocate reserves all rights to object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's data requests to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the

2. The Consumer Advocate objects to the data requests to the extent they call for information and the production of documents which are protected from disclosure by the attorney-client privilege, the attorney work product doctrine or any other applicable privilege or protection. In particular, the Consumer Advocate objects to requests seeking its legal research related to pertinent statutes, rules, orders and case law The Consumer Advocate objects to the data requests to the extent that the Company is attempting to impose on the Consumer Advocate obligations with regard to identification of privileged documents beyond those required by the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

3. The Consumer Advocate objects to the Company's data requests to the extent they seek information relating to matters not at issue in this litigation or to the extent they are not reasonably calculated to lead to the discovery of admissible evidence. By providing information in response to these requests, The Consumer Advocate does not concede that such information is relevant, material or admissible in evidence The Consumer Advocate reserves all rights to object to the use of such information as evidence.

4. The Consumer Advocate objects to the Company's data requests to the extent that the Company is attempting to require the Consumer Advocate to provide information and produce documents beyond those in its possession, custody or control as that phrase is used in the *Tennessee Rules of Civil Procedure* and applicable statutes and regulations governing contested case hearings.

5. The Consumer Advocate objects to the Company's data requests to the extent they seek information and documents that are readily available through public sources or are in the

Company's own possession, custody or control. It is unduly burdensome and oppressive to require the Consumer Advocate to respond or produce documents that are equally available to the Company.

6. The Consumer Advocate's objections and responses to these requests are based on information now known to it. The Consumer Advocate reserves the right to amend, modify or supplement its objections and responses if it learns of new information.

7. The Consumer Advocate's responses to these requests are made with out waiving or intending to waive the right to object to the use of any information provided in response to any subsequent proceeding or trial of this or any other action. The Consumer Advocate's responses to these requests are also not a waiver of any of the foregoing objections or any objections it has made or may make with respect to any similar, related, or future data request, and the Consumer Advocate specifically reserves the right to interpose any objection to further requests notwithstanding any response or lack of objection made in this response.

8. The Consumer Advocate objects to the any request seeking all documents reviewed by its witnesses over an undefined time period. Such a request is ambiguous, overly broad, burdensome and is not likely to lead to the discovery of admissible evidence.

9. The Consumer Advocate expressly incorporates these general objections into its responses set forth below.

DISCOVERY REQUESTS

REQUEST # 1. Please produce copies of all articles referenced in the Direct Testimony of Steve Brown, page 2, line 28.

RESPONSE: Subject to and without waiving any objections stated above the Consumer

Advocate responds to the specific request as follows:

Copies of the articles are attached.

REQUEST # 2. Identify all facts Mr. Brown relies upon in support of his assertion at page 5, lines 17-18 of his Direct Testimony that "the risk of penalty or loss is fundamental to the PBR." Produce all Documents Mr. Brown reviewed or relies upon in making that assertion, including without limitations, all statutes, rules, orders, and cases.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request about Dr. Brown's testimony as follows:

Much of the information sought by this request is contained or referenced in TRA Docket Nos. 97-01364, 00-00844, 01-00704, 02-00850 and 03-00209. Of particular note are the Phase One Order and Phase Two Order in TRA Docket No. 97-01364. By way of example the Consumer Advocate notes the following (but not exhaustive) list:

1) See the TRA's "Final Order On Phase One," Ordering Clause 1 at page 28:

> The Tennessee Regulatory Authority has the statutory power to approve a performance- based incentive mechanism which automatically penalizes or rewards the public utility for its performance ....;

2) See the TRA's "Final Order On Phase One," Procedural Background at page 2: and

> "The proposal was designed to create an incentive to perform better than.. the market and to penalize the Company [for] ... a price of gas above the pre-defined benchmarks."

3) See the TRA's "Final Order On Phase One," at page 27, where the TRA rejected the NORA contract as a portion of the PBR because, according to the TRA,

> "Including it in the incentive mechanism would 'guarantee' a bonus to the Company."

REQUEST # 3. At page 6, lines 18-21, Mr. Brown states that "[m]y professional opinion as an economist is that the PBR is a 'ratemaking'." Please describe and/or define in detail what Mr. Brown means by identifying the PBR as a "ratemaking." Describe the significance of Mr. Brown's conclusion, at page 6, line 21 of his Direct Testimony, that the PBR is a "ratemaking."

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request about Dr. Brown's testimony as follows:

The term "ratemaking" was used because it accurately describes the PBR and, as well, AEC's attempts to amend it. The significance of this testimony, like all testimony in this proceeding, will be determined by the Hearing Officer and the TRA. However, the concept of what constitutes "ratemaking" relates to at least two (2) issues: 1) whether the amendment to the PBR requested by AEC constitutes retroactive ratemaking; and 2) identifying the proper legal standard(s) in this matter.

To the extent that this request is seeking a further explanation for Dr. Brown's characterization of the PBR as a "ratemaking", the Consumer Advocate offers this explanatory (but not exhaustive) statement:

See responses to Request # 2 and # 8. The PBR is a ratemaking for several reasons. Approval by the TRA of the PBR mechanism changed the rates Tennessee's consumers pay for the delivery of gas. This will be the result in this docket if the TRA accepts any of AEC's proposals.

Further, the Company's rate of return changed upon approval of the PBR. The PBR directly and intentionally affects the Company's authorized rate of return and is therefore a ratemaking. The PBR, therefore, is quite different from any procedure which limits itself to giving the Company only cost-recovery, such that the procedure neither raises nor lowers the Company's authorized return. The PBR's "automatic" penalty occurs through the lowering of the Company's rate of return authorized by the TRA, as Dr. Brown testified to his direct testimony, in TRA Docket No. 97-01364, page 13 lines 9-31, and is clear proof that the PBR is a ratemaking:

> "Q. Mr. Williams also asked you some questions about basis points and rate of return on equity and what the staff recommended in that case. You understand that the way this plan works is if United Cities does not do a very good job of purchasing gas that it can incur a penalty and the result of that penalty would essence be a lowering of their authorized rate of return?"
>
> "A. The penalty would be a lowering of their rate of return?"
>
> "Q. Yes. Based upon the answer that you gave to Mr. Williams about the fact that if they were awarded, that, in essence, would increase their rate of return?"
>
> "A. Would increase their overall return -- or decrease their overall return, what you said. But there would be no Commission action that would penalize them. The plan itself would take care of that.
>
> "Q It's an automatic penalty?"
>
> "A. Yes." [Transcript, Thursday, March 26, 1998 Volume I, page 285, lines 6-25 and page 286, line 1]"

As the TRA itself said in TRA Docket No. 97-01364 in the "Final Order On Phase One" at page 10:

> "...the TRA has the discretion to approve proposed rate changes that have been submitted to it by a utility under its jurisdiction... the General Assembly requires the rates set by this agency be just and reasonable... the TRA has the discretion to determine what constitutes just and reasonable rates..."

Further the TRA noted in TRA Docket No. 97-01364 in the "Final Order On Phase One" at page 11:

> "In summary both parties acknowledge the authority of the TRA to act to set rates in cases such as this."

The caption of the pertinent dockets include a reference to "Performance Based Ratemaking" and is clear reference to "ratemaking."

In discovery responses, AEC identifies a Tennessee statute which deals with ratemaking as setting the standard for which its proposed amendment to the PBR will be judged.

Regarding the significance of the ratemaking, the TRA has concluded within the context of its PBR orders that retroactive ratemaking is to be avoided. Pertinent references may be found in TRA Docket No. 97-01364 in the "Final Order On Phase One" at page 17 and 18:

> "The independent consultant, Mr. Frank Creamer, recommended four (4) modifications the Company asserts should be adopted in their entirety. These proposed modifications were as follows:
>
> 1. Increase the cap from $25,000 per month to $600,000 per year to be calculated annually....."
>
> "Further, to accept the first modification at this point in time could be construed as retroactive ratemaking."

REQUEST # 4. Identify all facts that Mr. Brown relies upon in support of his statement, at page 7, lines 7-11, that the Authority has a "clear policy that the incentive program be conditioned by the Company's gains and losses, rather that being conditioned solely by gains." Produce all Documents Mr. Brown reviewed or relies upon in making that assertion, including, without limitation, all statutes, rules, orders, and cases.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request about Dr. Brown's testimony as follows:

Dr. Brown is not able to identify all the documents he has "reviewed" over the last several years that may fall within the scope of this request.

See response to Request # 2. Dr. Brown relies on his experience and the following separately identifiable facts and documents:

See the TRA's "Final Order On Phase One," at page 27, where the TRA rejected the NORA contract as a portion of the PBR because, according to the TRA:

> "Including it in the incentive mechanism would 'guarantee' a bonus to the Company."

See the TRA's "Final Order On Phase One," at page 23, where the TRA notes and recognizes:

> "Even those uninitiated in the art of mathematics recognize that the development of an arithmetic mean requires input values lower than the mean and input values higher than the mean."

See the TRA's "Final Order On Phase One," at page 25, where the TRA notes and recognizes:

> "In determining whether performance based incentive plans are appropriate ratemaking , the regulator must first accept the external benchmark as an appropriate proxy for the market price. Frank Creamer stated that the benchmark served as a proxy for the market price. Mr. Novak agreed that the average of the three (3) indices are a proxy for market price."

REQUEST # 5. Please produce copies of all testimony referenced in the Direct Testimony of Daniel W. McCormac, page 2, line 26.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request as follows:

Mr. McCormac has testified in the following major natural gas cases since July, 1994, including but not limited to:

United Cities Gas 95-01134

United Cities Gas 95-02258

United Cities Gas 97-01364

Nashville Gas Company 94-01054

Nashville Gas Company 96-00977

Nashville Gas Company 99-00994

Nashville Gas Company 03-00313

Chattanooga Gas Company 95-02116

Chattanooga Gas Company 96-01174

Chattanooga Gas Company 97-00982

Chattanooga Gas Company 02-00383

Chattanooga Gas Company 04-00034

Atmos Energy, Chattanooga Gas Company and Nashville Gas Company 03-00209

See response to Request # 2. The Consumer Advocate is not aware of any such testimony which is not available to AEC as a public document at the TRA. To the extent the testimony is not available to AEC, the Consumer Advocate will attempt to assist AEC in obtaining these documents.

REQUEST # 6. Identify all facts Mr. McCormac relies upon in making the assertion at page 6, lines 1-11 of his Direct Testimony. Produce all Documents Mr. McCormac reviewed or relies upon in making those assertions.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request as follows:

See response to Request # 2. The testimony refers to "Attachment B" as an illustrative example gleaned from a common sense approach taking into consideration many factors including the fact that industry members have both the motive/incentive and opportunity to make sales and purchasing decisions that result in higher profits and not necessarily the best cost to consumers. Many of the references are cited in the NASUCA Resolution which is "Attachment B." There have been numerous news articles which refer to similar problems. The TRA staff audit reports have referred to similar problems. The FERC and Commodities Futures Trading Commission investigations are ongoing.

On September 25, 2002, Dynegy announced that they had discovered that 15 Dynegy employees had engaged in reporting false data to trade publications that publish price indices. On December 18, 2002, the Commodity Futures Trading Commission announced that it had reached a $5 million settlement with Dynegy and West Coast Power, LLC. The settlement stated that Dynegy had "knowingly submitted false information to the reporting firms in an attempt to skew those indexes to Dynegy marketing & Trades' financial benefit."

On October 9, 2002, American Electric Power (AEP) announced that it had "dismissed five employees involved in natural gas trading and marketing after the company determined that they provided inaccurate price information for use indexes complied and published by the trade publications."

On October 25, 2002 Williams announced it had learned that natural gas traders had provided inaccurate information regarding natural gas trades to an energy industry publication that compiles and reports index prices. Williams states that the inaccuracies came to light during Williams' independent, internal review of its trading activities.

On November 4, 2002, CMS Energy Corporation (CMS) announced that it was conducting an internal review of the annual gas trade information provided to the trade press by two subsidiaries; CMS Marketing Services and Trading and CMS Field Services. CMS stated that a preliminary analysis indicated that employees had provided inaccurate data. CMS further stated that it would take appropriate disciplinary action and that it would stop providing information to the Trade Press.

On November 8, 2002, the El Paso Corporation announced that it had discovered evidence that one of its employees had misreported trade data to the Trade Press. On December 4, 2002, the United States Department of Justice indicted Todd Geiger, a former vice president of El Paso Energy, on charges of false reporting and wire fraud. On January 13, 2003, federal prosecutors in court for a pretrial conference in the Geiger case told U.S. District Judge Nancy Atlas that there was a conspiracy among El Paso traders to provide bogus price information dating back at least two years. Also on January 13, 2003, El Paso issued a statement saying it had found more instances of its traders providing inaccurate information to *Inside FERC*.

Mr. McCormac has reviewed several sources and attended meetings and seminars discussing these problems, but he has not accumulated documentation for this specific purpose. Therefore, not all the requested information is available. Following is a list of items representative of those reviewed and/or which provide information potentially relevant to this issue:

TRA Docket No. 03-00516 (Chattanooga Gas)

TRA Docket No. 03-00489 (Nashville Gas)

"Misreporting of Energy Prices to Indexes Was Commonplace", Wall Street Journal, 11/19/202

"Natural-Gas Prices Thrown in Doubt", Wall Street Journal, 11/2002 (copy attached)

Natural Gas Markets Conference before FERC, Docket No. PL02-9-000

Amendments to Blanket Sales Certificates before FERC, Docket No. RM03-10-000

Price Discovery in Natural Gas and Electric Markets before FERC, Docket No. PL03-3-000

REQUEST # 7. Describe "the detailed audit and review" Mr. McCormac refers to on page 6, line 4 of his Direct Testimony.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request as follows:

Circumstances require a thorough audit of the ACA account and all costs billed to consumers (whether through base rates or through the ACA) for assets that are sold under incentive plans in such a manner that the company could be rewarded for inflating costs or making transactional decisions which may lead to an increase in the amount of "savings" claimed, but also lead to an increase in the best cost to consumers. The audit should include all aspects of the costs including, planning, documenting and implementing the efficient management and operations of all controllable costs. This means an audit, which at a minimum, reviews and verifies the appropriate actions and recording of actions and transactions concerning all costs of gas and related transactions. The audit should include but not be limited to answering the following:

1) Whether AEC considered and utilized all appropriate sources of gas, transportation, storage, capacity, etc.,

2) Whether AEC maintained records documenting how all options are evaluated;

3) Whether AEC has proper documentation to show all steps taken to assure the best options were considered and why;

4) Whether all related party transactions were properly documented and supported;

5) Whether AEC correctly allocated and billed appropriate costs; and

6) Whether there are appropriate incentive measures in place to encourage productive behavior from the consumer's perspective as well as from the stockholders, managers, and affiliated companies' perspectives?

REQUEST # 8. Identify all facts Mr. McCormac relies upon in reaching his conclusion at page 11, lines 8-10 of his Direct Testimony, that approval of the proposed TIF tariff "would constitute retroactive ratemaking." Produce all Documents, including, without limitation, all statutes, rules, orders, and cases, Mr. McCormac reviewed or relies upon in reaching that conclusion.

RESPONSE: Subject to and without waiving any objections stated above the Consumer Advocate responds to the specific request as follows:

See response to Requests # 2 and 3. First, it is undisputed that AEC is seeking retrospective relief. Secondly, it is clear that the PBR and AEC's proposed amendment to it constitutes ratemaking. Thirdly, although it is uniquely within the province of the Authority to make the legal determination about "retroactive ratemaking," it is noteworthy that the PBR is particularly prospective in structure because it is designed to provide the TRA with an opportunity to exercise regulatory oversight by setting out, in advance, meaningful and objective incentives. Mr. McCormac reviewed the discussion in the current record dealing with this issue. In addition, he is aware through his personal experience of the concept of setting rates prospectively rather than retroactively. Simple logic dictates that something cannot be "approved" prior to its submission for review and acceptance by the Directors of the TRA. In this instance, an amendment to the PBR has not been approved by the TRA. Neither, the fact that AEC filed an amendment to the PBR in TRA Docket No. 02-00850, nor the fact that AEC claims it explained a new direction for the PBR to the TRA Staff at a meeting in January, 2001, change this fact. In each docket, Atmos asks for a change in the formula for computing the rate a customer is charged. It would be inappropriate for the TRA to fix rates retroactively. The focus of the TRA to prescribe rate changes, upward or downward, should be prospective only. Otherwise, AEC will surprise customers, who paid the tariffed rate for a service, by telling them that they must now pay an increased price for past services. These customers will be improperly required to pay for past use.

Respectfully submitted,

FOR THE STATE OF TENNESSEE:

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served via facsimile transmittal and by U.S. Mail on September 1, 2004.

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VOL 112 NO 10

The Public Power Industry in the West: Primacy of Contracts over Economic

By STEPHEN N BROWN

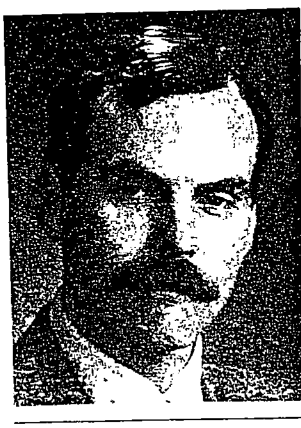
Public power utilities in the United States which are in a period of transition from being strictly power purchasers to being power producers face an economic loss of efficiency Average pricing policies appear to be ineffective tools in controlling sales patterns in the presence of long-term purchased power contracts The benefits of new base-load generation are transferred to short-term customers as the growth of firm power sales lags This article examines some of the problems encountered by three such organizations and recommends several possible long-term solutions

THE term "load factor" is common in many industries, particularly regulated utilities, because it is a standard measure of efficiency The general goal of a business is to improve its load factor whenever possible because it directly affects profits

> Load Factor This may affect earning power substantially A utility is required to have capacity adequate to meet the maximum demand for its service at any time The maximum is the peak load Actual output in a given period, such as a month or year, divided by what would have been produced at continuous peak-load operation is the load factor The higher the load factor, other things being equal, the more profitable the operation, for plant capacity is idle a lesser percentage of the time [1]

But within the public power industry, there is no profit incentive in the sense that public power entities specifically declare themselves to be nonprofit enterprises If

[1] *Financial Handbook*, by Jules I Bogen and Samuel Shipman Eds, John Wiley and Sons, New York, 1964 Chap 7 p 19



Stephen N. Brown is a rate analyst with the Arizona Electric Power Cooperative, Inc and has worked in public power for over five years in the areas of financial planning forecasting and rate analysis **Dr. Brown** received his MS degree in regulatory economics from the University of Wyoming and his PhD degree from the University of Denver

this is the case, then what role does load
the pricing policy of public power entities
specious answer would be "none" Of cour
true, anyone who works in the public p
knows that the load factor issue is addres
two-part demand and energy-pricing s
sometimes referred to as a Hopkinson r
type is a standard one and used through
and private power industries However, fro
case study two definite conclusions will e
spite the use of Hopkinson rates, load fac
play no role in shaping some public power
aggregate load patterns and aggregate cus
to price changes, (2) purchase power co
federal entities and a public power org
govern that organization's pricing policy

These two specific conclusions will le
general conclusion When a public pow
makes the transition from being strictly a
to being also a producer, the transition
hampered by existing contracts to purch
contracts impose economic inefficiencies
tion making the transition, newly acqu
facilities cannot be operated in an optimu
out substantial short-term and economy s
power, thus the immediate benefits of ge
sion flow primarily to the short-term ma
to the firm power customers, the intend

If the long-term contracts cannot be ch
public power organization should abandon
ture used prior to becoming a produc
new structure, one that promotes the m
of the new facilities The remainder c
divided into two parts The first section
review of the Hopkinson rate and how l
a role in that rate, the second provides t

...usly mentioned.

The Hopkinson or Two-part Rate

Since nearly all utilities bill customers in a monthly framework, the usual way to compute average price in mills per kilowatt-hour from a two-part demand and energy rate is

$$A = \frac{mdp}{MLF \times H} + e$$

Where A equals average monthly price in mills per kilowatt-hour,
mdp equals metered demand price per maximum monthly kilowatts,
MLF equals monthly load factor expressed in two significant digits to the right of the decimal point and $0 \leq MLF \leq 1$,
e equals price of metered energy per kilowatt-hour,
and, H equals number of hours in the month.

Given the prices for metered demand, metered energy, and the hours in a given month, the average monthly price depends only on the individual system's monthly load factor. the above formula is standard, but its use has been severely criticized[2], yet many utilities continue to apply it. Of course, the two-part rate does recognize load factor, the higher the monthly load factor, the lower the average cost.

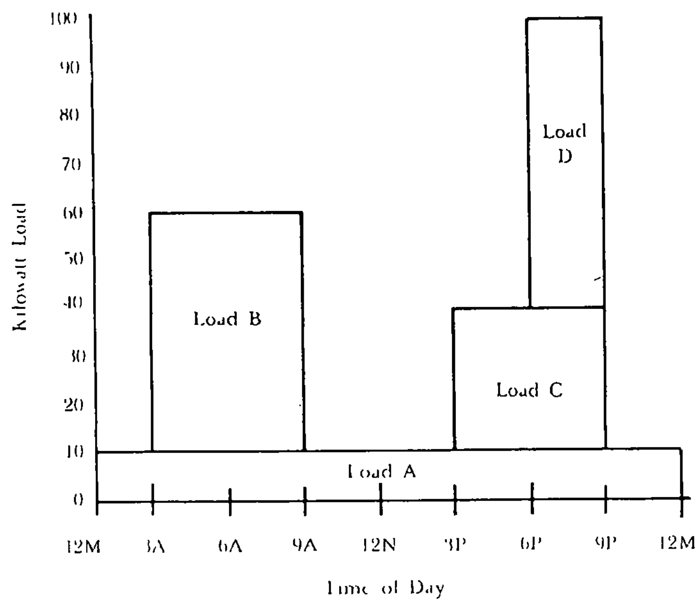
The Hopkinson rate draws criticism primarily because of the way it is applied and not because of the formula itself. This can be seen most clearly by distinguishing between coincident and noncoincident demands. Coincident demand means the instantaneous maximum system peak occurring during a particular time period, conversely, noncoincident demand means the sum of each customer's or individual load's maximum peak regardless of the time of occurrence. Figure 1 provides a convenient way to illustrate these points. According to the figure the instantaneous maximum load of the system is 100 kilowatts and the time of the occurrence is 9:00 P.M. This is the coincident demand. Load A contributes ten kilowatts, load B contributes nothing, load C contributes 30 kilowatts, load D contributes 60 kilowatts. However, the noncoincident demand is the sum of all the loads whether or not they contribute to the system peak. In this case the noncoincident demand is 150 kilowatts because B's load is added to the other loads.

When the Hopkinson rate is applied, which measure of demand should be used, coincident or noncoincident? In the first case load B pays nothing and the other loads pay all demand costs, in the second case load B contributes one-third (50-150) of the demand costs. Many utilities, therefore, use the noncoincident measure. Critics of this procedure contend that load B is penalized and that its payment amounts to a subsidy of the other loads that do cause a need for capacity. This discussion shows that measurement is quite important to pricing policy, but measurement can be in terms of a day, a week, a month, or a year.

For example, if time of the month were on the horizontal axis of Figure 1, then the noncoincidental demand would be 150 kilowatt-months. If 150 kilowatt-months were used each month during an annual or 12-month period, then demand use during the year would be 150

[2]*The Economics of Regulation: Principles and Institutions.* Volume 1, Economic Principles, by Alfred Kahn. John Wiley and Sons, New York 1970, pp 95-96.

SUMMARY OF CAPACITY ALLOCATION METHODS



Load	*Demand*	*Comments*
A	10 Kw	Base Load
B	50 Kw	All Off-peak
C	30 Kw	Both On-peak and Off-peak
D	60 Kw	All On-peak
System Peak =	100 Kw	
Connected Load =	150 Kw	

Allocation by Peak Responsibility Method

Load	*Allocated Responsibility Kilowatts*	*Per Cent*
A	10	10
B	0	0
C	30	30
D	60	60
	100	100

Allocation by Noncoincident Peak Method

Load	*Allocated Responsibility Kilowatts*	*Per Cent*
A	10	6.67
B	50	33.33
C	30	20.00
D	60	40.00
	150	100.00

kilowatt-months multiplied by 12, or 1,800 kilowatt-months.

In the case study that follows, annual demand figures are noncoincident monthly demand figures summed over twelve months. The case study refers to demand in terms of an annual kilowatt month or an annual megawatt month, which is 1,000 times larger than a kilowatt month. Utilities usually bill customers on a monthly basis, which is a normal revenue cycle, thus kilowatt months are a main determinant of the revenue flowing into a company.

Case Study

In major portions of the western United States, the Western Area Power Administration has played the preeminent role in the generation and transmission of electrical power to rural electric distribution systems, municipal distribution systems, and cooperatively owned generation and transmission associations. Western currently supplies electrical power to many entities: Tri-State Generation and Transmission Association, Inc., the Platte River Power Authority, several members of the Basin Electric Power Cooperative, and to small municipalities throughout Montana, Wyoming, Colorado, Nebraska, North Dakota, and South Dakota. These customers represent just a portion of Western's customers, but this case study focuses on Tri-State, the PRPA, and Basin; these are major bulk power suppliers in the northern Rockies. Western delivers electrical energy and demand to these entities by way of the existing federal transmission system and federal delivery points; the quantities of energy and demand received by each entity are stipulated in long-term contracts according to specific formulas. (The term energy refers to kilowatt-hours; the term demand refers to maximum kilowatts during a specified time period.)

In the 1950s, Western was the primary, if not the only, power supplier to these systems. In the late 1960s and early 1970s Western took the policy position that it could no longer meet the growing needs of its customers; the customers themselves would have to provide additional capacity. They embarked on their own generation expansion and faced the transition from being strictly a purchaser to being a producer. As Tri-State and Basin began their search for power, four cities in northern Colorado (Fort Collins, Loveland, Longmont, and Estes Park) formed the PRPA for the same purpose.

Generation expansion is expensive; it causes a radical change in both the level and pattern of expenditures of the affected organization. The nature of the change is dependent on the type of plant that the organization builds to supply that portion of load not covered by purchases from Western. Is that load portion to be met by a base-load plant or a peaking facility? What are the locations and sizes of new transmission lines? Pricing policy must also be analyzed. Should the rate structure change to reflect the new investment patterns? Will sales patterns change because of corresponding changes in rate level and rate structure? Long-range planners must incorporate the answers to these questions into investment decisions and ongoing pricing poli[cies].

Tables 1 through 3 show the annual sales of demand and energy by each organization to its membership. The power that Basin supplies to its membership is supplemental to the member's power purchases from Western's power deliveries. Basin's sales are added to a sales pattern already established by Western's power deliveries. The far right-hand column of each table reveals a very peculiar aspect of the sales pattern. Year after year, the energy quantity is a fixed proportion of the demand quantity. That particular column can also be interpreted as the number of kilowatt-hours sold per kilowatt sold. Therefore, with respect to 1979 in Table 3, 475 kilowatt-hours were sold for every kilowatt sold. Table 4 shows the 1980 month-by-month demand and energy purchases by Tri-State from two of Western's projects: the Colorado River Storage Project, and the Missouri River Basin Project. The CRSP delivers power to Tri-State for its resale in Colorado and Wyoming only; the MRBP delivers power to Tri-State for its use in Colorado, Wyoming, and Nebraska. The ratio of the annual total in Table 4 is reflected in the ratios of the annual totals in Table 1. As stated before, each of the three organizations made investments to meet load growth not covered by purchases from Western. However, the available evidence suggests that the specific load growth not covered by purchases from Western has, in fact, a pattern that is nearly identical with the load that is supplied by Western. The total load pattern of each of the three organizations is a replication of the load pattern established in Western's power deliveries.

But this does not mean that a system's annual load factors remain unchanged. Table 5 lists the annual load factor for Tri-State from 1966 through 1980. The annual load factor declines yet the billing quantities shown in Table 1 maintain a constant ratio to each other over the same time period.

Table 1

Annual Sales of Energy and Demand by Tri-State To Its Membership

Year	Energy (Gigawatt hours)	Demand (Megawatt-months)	Energy Demand
1965	1,103.3	2,177.8	507
1966	1,168.3	2,336.6	500
1967	1,209.5	2,425.3	499
1968	1,406.0	2,801.4	502
1969	1,519.3	3,075.7	494
1970	1,684.1	3,390.9	497
1971	1,833.0	3,637.5	504
1972	2,019.9	4,082.8	495
1973	2,199.7	4,416.4	[illegible]
1974	2,490.1	4,959.8	[illegible]
1975	2,718.1	5,566.1	488
1976	3,100.4	6,455.8	480
1977	3,191.5	6,504.8	491
1978	3,648.8	7,319.7	498
1979	3,612.8	7,300.3	496
1980	3,723.9	7,500.9	496

Source: Tri-State History Sales Report 1965-80

TABLE 2

ANNUAL SALES OF ENERGY AND BILLED DEMAND BY BASIN TO ITS MEMBERSHIP

Year	*Energy (Gigawatt-hours)*	*Demand (Megawatt-months)*	*Energy ÷ Demand*
1971	838 5	1,711 2	490
1972	1,143 2	2,421 2	472
1973	1,335 7	2,808 0	476
1974	1,825 6	3,754 5	486
1975	2,306 5	4,776 0	483
1976	2,870 1	5,990 6	479
1977	3,509 2	7,261 5	483
1978	4,013 4	8,189 4	490
1979	4,310 1	8,709 4	495
1980	4,389 7	8,866 7	475

SOURCE The annual entries for energy (gigawatt-hours) are also listed in the annual Rural Electrification Administration Bulletin 1-1, the items for demand (megawatt-month) are also available on Basin's monthly REA Form 12b, Column 6, for January, 1971, through December, 1980 This form is on file with Basin and with the REA

The information in Tables 1 through 4 shows the commodities that are actually sold, each table demonstrates that on an annual basis the energy commodity, gigawatt-hour, is related to the demand commodity, megawatt-months, by a constant ratio (A gigawatt-hour is one million times larger than a kilowatt-hour) Hence the two commodities are not independent of each other, but in fact are perfectly correlated Also, the ratio is nearly the same from year-to-year and not substantially different between the organizations even though they serve different customer mixes The PRPA serves cities, while the other two organizations serve rural areas The ratio is directly related to rate structure when prices for firm power supply are based on a fully allocated cost methodology, sometimes referred to as average pricing methodology

Tri-State, Basin, and PRPA use the average pricing methodology, which is a straightforward procedure The procedure begins with a simple question What is the revenue requirement for the rate year? Once this figure is set, the next question is, how much demand, megawatt-months, will be sold during the rate year? If the entire revenue requirement were to come from megawatt-months, what would be the price per megawatt-month? Total revenue requirement must be divided by total megawatt-months How much energy, gigawatt-hours, will be sold in the rate year? If the entire revenue requirement were to come from gigawatt-hours, what would be the price per gigawatt-hour? The total revenue requirement must be divided by total gigawatt-hours

The entire procedure is summarized by Figure 2 The vertical axis represents the price of demand per megawatt-month, and the horizontal axis represents the price of energy per gigawatt-hour The maximum price per megawatt-month, point P, is found by dividing the total revenue requirement by total megawatt-months The maximum price per gigawatt-hour, point Q, is found by dividing the annual revenue requirement by total gigawatt-hours The slope of line PQ is equal to gigawatt-hours divided by megawatt-months, the points between P and Q on the line represent prices that would be derived if part of the revenue requirement were allocated to demand and the remainder were allocated to energy Figure 2 demonstrates a major point The ratio of the demand quantity to the energy quantity determines the available combinations of demand price and energy price that the company can charge to buyers The particular combination of demand price and en-

TABLE 3

ANNUAL SALES OF ENERGY AND BILLED DEMAND BY THE PLATTE RIVER POWER AUTHORITY TO ITS MEMBERSHIP

Year	*Energy (Gigawatt-hours)*	*Demand (Megawatt-months)*	*Energy ÷ Demand*
1973	530 8	1,124 0	472
1974	558 8	1,157 3	483
1975	614 8	1,290 1	477
1976	678 1	1,417 3	478
1977	739 7	1,552 7	477
1978	836 7	1,743 5	480
1979	911 9	1,889 6	483
1980	957 3	2,013 6	475

SOURCE Letter of May 7, 1981, from Mr Robinson of Platte River Power Authority to author

TABLE 4

TRI-STATE MONTHLY DEMAND AND ENERGY PURCHASES FROM WESTERN FOR 1980

Months	*Energy (Gigawatt-hours)* MRB (Colo) + CRSP (Colo) + MRB (Neb)	*Demand (Megawatt-months)* MRB (Colo) + CRSP (Colo) + MRB (Neb)	*Energy ÷ Demand*
January	174 3	390 2	447
February	158 0	388 8	406
March	161 1	351 8	458
April	153 1	340 2	450
May	178 7	346 6	515
June	232 7	449 0	518
July	292 9	502 4	582
August	289 5	499 5	580
September	194 2	422 0	460
October	166 7	357 9	466
November	170 5	360 7	473
December	175 2	365 7	479
Total	2,346 9	4,774 8	492

SOURCE 1980 billing records and invoices of Tri-State

FIGURE 2

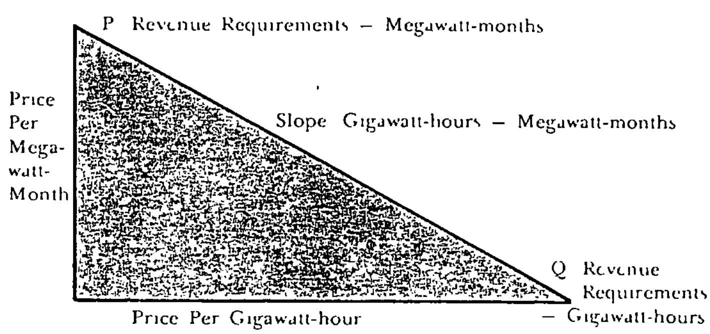


TABLE 5

TRI-STATE ANNUAL LOAD FACTOR*

1980	45.0%
1979	45.3
1978	45.8
1977	42.3
1976	43.7
1975	43.1
1974	46.4
1973	48.1
1972	48.4
1971	49.4
1970	50.5
1969	50.3
1968	52.9

*Load factor is based on diversified demand.
SOURCE: Tri-State history sales report 1968–80.

ergy price is determined by an allocation procedure or a policy decision of the company.

The evidence accumulated here clearly suggests that the demand and energy quantities delivered by Western to its customers, as stipulated by long-term contracts, are controlling the demand and energy price combinations that Tri-State, Basin, and PRPA can apply to their customers. The particular point selected on line PQ of Figure 2 merely rearranges the distribution of revenue requirement among the different buyers.

For example, if a buyer's ratio of energy purchases to demand purchases is greater than the slope of line PQ, then the buyer would prefer to see the seller's entire revenue requirement allocated to demand because this would minimize the buyer's payments for power. If a buyer's ratio of energy purchases to demand purchases is less than the slope of line PQ, then the buyer would prefer to see the seller's entire revenue requirement allocated to energy because this would minimize the buyer's payments for purchased power. The information in Tables 1 through 4 also implies that as a company's revenue requirements increase, the line PQ of Figure 2 would shift outward in a parallel manner keeping the slope constant. The information and analysis of wholesale pricing raise some fundamental questions. If price combinations are governed by quantity combinations, which in turn are stipulated by contract, then are sales patterns responsive to pricing policy? The answer is no, pricing policy appears to be an ineffective tool in the presence of contracts. Could any point on line PQ be selected without having an impact on the company's sales patterns? The answer is yes, which implies that demand and energy sales have no cross elasticity between them, the sales are always related by a constant proportion. From this it follows that the slope on line PQ can change only slightly, if at all.

The implications of these patterns must be clearly stated. The constant ratio of energy to demand implies that energy conservation, whether at the time of system peak or not, brings about a proportionate reduction in demand consumption. From the standpoint of the wholesale supplier, a reduction in an energy sale causes a proportionate reduction in a demand sale. Consequently, demand revenue falls in proportion to the decline in energy revenue, the revenue requirement can be met only by increasing prices. Therefore, prices cannot induce an improvement in system load factor and reduce idle capacity.

However, this relationship also implies that there is a great deal of revenue stability built into the pricing system. Management does not have to worry about the impact of rate structure on sales patterns, for

$$Q_1 = K\ Q_2,$$

Where Q_1 = the quantity of energy,
Q_2 = the quantity of demand,
K is a positive constant,

and

$$RR = P_1\ Q_1 + P_2\ Q_2$$

where RR = revenue requirement,
P_1 = the price of energy,
P_2 = the price of demand,

then

$$RR = Q_2\ (K\ P_1 + P_2)$$

But this information also has implications about the usefulness of marginal pricing policy as indicated by the following quotation from Alfred Kahn's work cited earlier:

> If services produced in common are to have separate marginal production costs, then it must be possible to vary their proportions. . . . When instead the products are truly joint in that they can be economically produced only in fixed proportions neither of them has a genuine, separate incremental cost function. . . . The economic unit is the composite unit, the only economically definable cost of production, marginal or average, and "price" or "marginal revenue" are those of the composite unit.[3]

The evidence compiled here shows that demand and energy are consumed in the aggregate as if they were a joint product. In fact, demand and energy appears to be a joint product in these systems. Therefore marginal pricing and all of the incentives for it in the Public Utility Regulatory Policies Act are not applicable to the organizations studied in this article. This is clearly a case where energy conservation contributes to rather than retards upward movement in prices.

Furthermore, revenue stability in this situation is not related to how a revenue requirement is allocated between demand and energy. Revenue stability depends only on how much of the joint product is actually sold. Arguments about the effect of allocation procedures on revenue stability are moot. Instead, the central issue should be the separation of demand and energy so that

[3] Ibid., p. 78.

they are no longer related by a constant proportion this particular pattern would have never been revealed a regulatory proceeding that focuses only on a test year, there is a need to examine historical data in regulatory proceedings

The source of this pattern and its regular occurrence year after year lies in a common feature of Western's contracts for the delivery of firm energy and demand Western limits its energy deliveries to a seasonal load factor of 58 2 per cent, more specifically, energy deliveries are generally limited to 2,550 kilowatt-hours per maximum kilowatt per season[4] (each season is six months long) The significance of this limitation for rate structure is shown in the following explanation There are two seasons per year in Western's contracts, the summer season of April through September and the winter season of October through March With regard to CRSP, Tri-State is allocated a maximum monthly demand of 252 megawatts in the summer season and 179 megawatts in the winter season The total annual energy available to Tri-State from CRSP is

$$\frac{2{,}550 \text{ Kwh}}{\text{Kw}} \times (252 \text{ Mw} + 179 \text{ Mw}) = 1{,}099 \text{ Gwh}$$

However, how many kilowatt-months are provided in a six-month period? In the summer season, 252,000 kilowatts are provided during one month, but in each of the remaining five months, less than 252,000 kilowatts are provided Adding up the kilowatt-months during the six-month period would yield a figure less than 6 × 252,000 The same procedure would apply to the winter season 179,000 kilowatts would be provided during one month but the total kilowatt-months in the six-month period would yield a figure less than 6 × 179,000

Thus, if the CRSP delivers 2,550 kilowatt-hours per maximum kilowatt per season, then how many kilowatt-months does the CRSP deliver for every 2,550 kilowatt-hours delivered? The far right-hand columns of Tables 3 and 4 suggests the answer During 1980 Western delivered 492 kilowatt-hours for kilowatt-month delivered, and dividing 2,550 by 492 yields 5 18

A major but clear conclusion is now inescapable The slope line PQ in Figure 1 is nothing more than Western's 2,550 kilowatt-hours per kilowatt seasonal limitation translated into a kilowatt-hour per kilowatt-month scenario in order to reflect a monthly billing cycle This is true not only for Tri-State but for Basin and PRPA as well The price combinations of line PQ are based on Western's contractual limitation of 2,500 kilowatt-hours per kilowatt, pricing strategy is clearly subordinate to quantity limitations specified by contract The significance of this is directly related to Western's importance as a supplier Table 6 shows that Western is the predominant supplier to Tri-State As Western provides a smaller portion of

[4]This information was first published in Colorado Power Pooling and Generation Dispatch Strategies, by Whitfield A Russell prepared for the Colorado Public Utilities Commission (Columbus Ohio, National Regulatory Research Institute, 1978) Occasionally Western will change this limit slightly if conditions warrant

TABLE 6

SOURCES OF METERED ENERGY SALES TO TRI-STATE MEMBERSHIP IN 1980 AND 1981

	1980	
	Energy	*Relative Per Cent*
Total Metered Energy Sales	3,724	100
Basin Supplied	974	26
Western Supplied	2,274	61
Tri-State Generation	474	13
	1981	
	Energy	*Relative Per Cent*
Total Metered Energy Sales	3,721	100
Basin Supplied	888	24
Western Supplied	2 300	62
Tri-State Generation	533	14

SOURCE REA Form 12C December 1980, December, 1981, Column (3) Losses of 7 per cent on CRSP are excluded
REA Form 12b December, 1980 December, 1981, Column (3)

firm power supply, the contract will play less of a role in pricing strategy

As noted in the beginning of this article, Western took the policy position that the customers had to meet their own growing needs, to meet their own needs, these customers invested mainly in base-load, coal-fired facilities However, Western resources are primarily hydroelectric, so how are the two kinds of facilities combined in day-to-day operations?

The best way to answer this question is by referring to the contract for electric service[5] between Tri-State and Western, which typifies the situation

Tri-State must take its energy from Western in a load pattern that satisfies the constraints that Western must meet to generate power in the first place, and Western has the ultimate authority in this matter Article 16, § E, states with regard to Colorado and Wyoming

> The United States shall have the right to restrict the taking of firm power and/or energy hereunder to conform generally with the contractor's (Tri-State) hourly load pattern at the U S points of delivery in Colorado and Wyoming [6]

A similar statement appears in Art 16, § A With regard to Nebraska, a similar statement appears in Art 14, § A

The extent of Western's contractual authority over scheduling patterns is shown most clearly in Art 20 of the contract The article's most important aspects are summarized here Section A provides that if Western and Tri-State cannot agree on what constitutes an appropriate monthly schedule for delivery of Western's power

[5]Contract for Electric Service, Interconnections and Transmission Service with Tri-State Generation and Transmission, Inc " United States Department of the Interior, Bureau of Reclamation Contract No 7-07-70-P0190 June 3 1977

[6]Ibid p 10

d energy to Tri-State, then Western can set its own monthly schedule Section B stipulates that Tri-State must prepare hourly schedules for auxiliary power, that power needed to meet firm load requirements in excess of the firm power provided by Western This information in conjunction with Western's authority given in Art 16, § clearly shows that Western has a great deal of control over the generation schedules of Tri-State's own power plants, the same ones built to meet load requirements that could not be met by Western The evidence demonstrates that the prevailing load pattern of Western's commitments is superimposed on its customers' new generating resources

A major factor affecting Western's contractual limitation is the problem of minimum release constraints on dams Major hydroelectric projects are frequently governed by interstate water compacts that require minimum acre-feet stream flow per second on the low side of the dam The operators of the hydroelectric project must adjust their own generation to meet the requirements of such a compact[7] However, this article is directed towards the effect of Western's scheduling procedure on its customers rather than the reasons why Western operates as it does

The new base-load plants were intended to sell power on a firm basis to the respective customers of Tri-State, Basin, and PRPA, yet the evidence compiled here shows that the entire pattern of firm power sales by each organization to its own customers is in fact identical to the pattern of purchased power An average pricing methodology simply reinforces rather than weakens the load pattern established by prevailing long-term contracts because load factors cannot be improved, hence the contracts dominate each system's load pattern and keep it from changing Therefore, the load pattern of firm sales for each organization taken as a single entity is not compatible with the pattern that the base-load plant was designed to produce, and the result is excess capacity In addition, these three systems will be forced into a prolonged excess capacity condition on base-load plants until the unchanging load patterns of their customers grow sufficiently to absorb the available capacity

Each utility added significant amounts of generation capacity from 1979 through 1981, but little of this has been used to meet the firm sales to each organization's membership The magnitude of the excess supply situation is shown in Tables 7 through 9

TABLE 7

SALES TO NONMEMBERS BY TRI-STATE

1980	1981
600 Gwh	1,756 Gwh

SOURCE REA Form 12b line 78, Column 3, December, 1980, December, 1981

[7]A good description of minimum release constraints appears in Colorado Power Pooling and Generation Dispatch Strategies," by Whitfield A Russell prepared for the Colorado Public Utilities Commission National Regulatory Research Institute, Columbus, Ohio, 1978

TABLE 8

PLATTE RIVER POWER AUTHORITY SALES AND SOURCES OF POWER

	Gigawatt-hours Twelve-month Period Ending October, 1980
Energy Received from Western	874
Energy Received from PRPA Owned Generation	492
Energy Delivered to PRPA Membership	980
Energy Sold to Nonmembers	297
	Gigawatt-hours Twelve-month Period Ending October, 1981
Energy Received from Western	820
Energy Received from PRPA Owned Generation	941
Energy Delivered to PRPA Membership	991
Energy Sold to Nonmembers	707

SOURCE Telephone call from John Allum of Platte River Power Authority to author December 2, 1981

Table 7 shows that Tri-State sold 600 gigawatt-hours to other utilities in 1980 and approximately 1,756 gigawatt-hours in 1981 Table 6 shows the source of metered energy sales by Tri-State to its membership during 1980 and 1981, in both years approximately 13 per cent of the total member sales came from Tri-State-owned resources Table 8 shows similar information for the PRPA. From November of 1980 through October of 1981, the PRPA received 941 gigawatt-hours from its newest generating station, an increase of 492 gigawatt-hours over the previous 12-month period, in the same time period sales to other utilities increased from 297 gigawatt-hours to 706 gigawatt-hours, an increase of approximately 410 gigawatt-hours Table 9 shows similar information for Basin for 1979 through 1981, as well as the now familiar pattern, sales to nonmembers have increased rapidly in contrast to member sales The tables make a single important point In 1980 and 1981, the output of the new generation facilities was purchased primarily by other utilities rather than by the membership of each organization Why has this happened?

Base-load plants are designed to operate at a fairly fixed kilowatt level over an extended period of time efficiency is greatest in this circumstance because operating costs per kilowatt-hour are minimized by continuous operation But if the member load is too small to permit continuous operation, then other buyers must be found

TABLE 9

BASIN ELECTRIC SALES TO NONMEMBERS

	Energy Sales to Nonmembers (Gigawatt-hours)
1979	31
1980	234
1981	1,053

SOURCE REA Bulletin 1-1, 1979, 1980, and 1981 erefore, when a utility finds itself in an excess capac- cond tion; additional sales must be found in the short- n nonfirm market Ideally, the utility will recover its iable cost of the sale and perhaps part of the fixed ts for the generating facilities

However, if several different utilities in the same gen- l location have excess capacity, then each one will n to the short-term market where they are in direct npetition with each other Tables 7 through 9 show each of the three utilities studied was able to make stantial sales to nonmembers But how long can this

his depends on the market for excess energy in Colo- o and Wyoming If that market does not expand, n there could be a twofold impact on prices Prices firm energy will rise because of high fixed costs ciated with the new investment while the firm sales me is constricted by the pattern noted above, but es for short-term energy fall or remain stable be- e of the prolonged excess capacity condition and use of competition The sale of short-term energy d approach an oligopolistic situation with each firm ng to underbid the others in an attempt to secure a ket for the excess energy This situation may be ipulated by a capacity-short utility to its own advan- by signing short-term contracts to meet its own loads ated before, this situation could continue until the customer loads grow sufficiently to absorb excess city, but this growth is retarded by upward pressure rices for firm power Thus, the immediate benefits neration expansion are transferred to short-term mers and the duration of this situation is enhanced e average pricing methodology applied to long- customers and the current power supply contracts lities always build facilities before the time they ctually needed, and an excess capacity condition typifies the period immediately after new plants e operational This is not unusual However, the itude of the excess capacity and the duration of ondition are critical to the long-term financial in- y of any utility These are the factors that each ization studied here must overcome in its quest for st power Yet, the pricing strategy of each organi- is subordinate to the power supply contracts with n, and generating schedules are rigorously con- l as well PRPA has recently responded to this on, by 1984 it will remove its newest generating om Western's load control center The PRPA can s because of its small geographical area, but Tri- nd Basin are still very much dependent on West- ransmission system and may not be able to im- their situations by unilateral action Negotiation mpromise with Western may be the only solution

Conclusion and Recommendations

Other public power utilities in the United States are now, or will be, in a period of transition from being strictly power purchasers to being power producers, and they could face the same problems encountered by the three organizations described in this study The long-term solutions can take one of seven forms (1) abandon the average pricing methodology and somehow encourage rather than discourage the growth of firm power sales, (2) broaden the short-term market by making appropriate changes in the transmission system and thereby increase revenue from this type of sale and decrease the revenue requirement from firm customers, (3) aggressively pursue power pooling arrangements, (4) permit the federal government to expand into major thermal generation projects rather than letting the purchaser transform itself into a producer, (5) let investor-owned utilities reach a negotiated settlement with the public power utility that needs more energy, (6) do not let the federal government control the scheduling of new generation resources to the extent of the present contract described in this article, (7) do not construct base-load plants, but build smaller units capable of operating over wide ranges of output at reasonable cost (Such units are often called swing units Operating costs for these units are generally higher than those of a base-load unit but the total capital investment would be less than the investment for a base-load unit)

Of the seven possibilities mentioned, the first is most feasible since it would be a policy decision internal to the public power organization and its membership, the remaining possibilities would probably involve more political risks than a public power entity or the federal government would desire But a public power entity faced with the transition already described should be fully aware that an average pricing methodology will probably reflect current power supply contracts and prolong the presence of excess capacity

There has been an economic loss of efficiency in the sense that the firm customers are underutilizing the new facilities, the economies of scale that are intrinsic to a base-load plant are not being passed on to the firm customers but to the short-term customers instead

If federal resources and newly constructed resources could be blended in a more efficient manner, then scale economics would lead to slower price increases and price stability Public power and the federal government should certainly examine this possibility Neither the organizations nor the consuming public can afford the underutilization of scale economics in new generation Public power and the federal government have to move towards more efficient pricing methods

Science and Technology

So Long, Calvin Coolidge

Meter Reading Approaches the 1990s Promising a Pivotal Market for Communications Infrastructure

By Stephen N. Brown

Federal and state regulators must become knowledgeable about Automatic Meter Reading (AMR) and all that it entails. After all, AMR is a pivotal market that will shape the nation's communications infrastructure by determining whether energy and water industries move toward an intelligent, public-switched communication network or toward radio-based personalized communication networks.

The junction lies in the eventual replacement of roughly 250 million electric, gas, and water meters in the United States, nearly all of which reflect the technology of the 1920s: they must be read manually, they are incapable of implementing time-differentiated rates, they cannot communicate with anything, and their information storage capability is nil. They will be replaced by devices embodying today's technology, and that will be compatible with the nation's communication infrastructure.

Radio Networks or Wired Networks?

The infrastructure is being shaped by the century-old competition between radio networks and wired networks. Radio-based cellular and microwave technology use the electromagnetic spectrum and offer the promise of personalized communication networks (PCNs) along with decentralized ownership and splintered control of the nation's communication infrastructure.

The AMR market already reflects the struggle over market position and the dichotomies between radio and wired technologies, and between unilateral control and integrated control. AMR products available today encompass various radio offerings, including one combination of spread-spectrum signalling with a power line carrier, as well as telephone-inbound/outbound strategies. Telephone-based products require cooperation between the local exchange carriers and the utility, the spread-spectrum/power-line device is unilaterally operated by the utility. However, there is no dominant AMR strategy or product in the electric, gas, and water industries, also, they have no organized strategy on how to migrate from a 1920's-vintage metering technology to the 1990s. The AMR market today is still immature, disorganized, and untapped, but loaded with potential.

Why?

Because replacing 250 million meters, not to mention possible markets abroad, represents a major demand for new manufactured products that embody new communication technology.

Capable Networks for Energy Industries

More capable networks are needed by the electric utility industry, which is under intense pressure to adopt energy efficiency strategies requiring load monitoring, load management, incentive rates, and perhaps eventually real-time pricing. AMR is essential for all these strategies. Therefore, regulators should advocate AMR investments in energy-utility networks, whether radio or cable-based, that

- have scale economies,
- possess multi-functionality,
- can easily implement rate structure changes,
- are consistent with open-architecture principles,
- avoid redundancy and duplication of another local utility's investments.

The regulatory community should take the lead in advocating economic cooperation between different utility industries—not only for the potential economic benefits but also because the utilities and American business in general do not value economic cooperation.

Shorter Replacement Cycles

The application to AMR and the regulatory process is this: Regulated industries should be responsive to continual product improvements in AMR. Regulators should not expect AMR products to have a 30- to 40-year depreciation schedule, nor should they expect utilities to make automation investments and then not replace them for decades. Product replacements are likely to occur in shorter cycles such as eight to twelve years. This is true for either radio or wired technologies.

An important feature of continual product improvement is the role of customer feedback in guiding incremental improvements to the product after it has been introduced. This sug-

The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Stephen N. Brown

The FERC completed a remarkable turnaround in regulatory philosophy in its gas pipeline restructuring order.

Competition for natural gas supply will promote the nation's economic growth That idea describes the essence of Federal Energy Regulatory Commission (FERC) Order No 636 and provides the driving force behind the commission's effort to restructure the natural gas industry But the FERC's eventual success ultimately depends on the spirit of "cooperative competition" The willingness of individual players to share information about day-to-day pipeline operations and the vital conditions that determine rate design and prices

The FERC itself is acutely aware of this vulnerability That is why the commission framed Order 636 with language that simultaneously coaxes, cajoles, and urges the industry to do its patriotic duty (see box)

This language makes FERC's order 636 truly remarkable It tells the pipelines that their traditional way of doing business blocks the spread of competition within the natural gas industry This finding was unthinkable twenty years ago The natural gas industry was built on the principle of bundled, city-gate, firm sales service During the industry's early years, certificates of convenience and necessity were issued to pipelines only if they offered such service to distribution companies The industry's building block is now an unlawful restraint of trade

The pipelines' old virtue is now a vice because the merchant function is gradually fading away In the first quarter of 1984 pipeline sales made up 94 percent of throughput By the second quarter of 1991 pipeline sales totaled only 12 percent of throughput Nevertheless, in 1991 pipeline sales consumed over 60 percent of peak-day capacity This surprising mismatch between throughput and capacity told the FERC that pipeline sales enjoy a clear advantage over the open-access firm transportation of nonpipeline natural gas

Free-flowing Information

The FERC intends to solve the fairness problem by establishing equivalency between bundled, city-gate firm sales by the pipeline and open-access firm transportation of nonpipeline natural gas The solution lies with the idea of "No-Notice Transportation Service" Success will depend on cooperation between the various segments of the industry, as the FERC is quite aware

> [We] expect the pipelines and all interested participants to craft the operating conditions needed to

The Spirit of 636

Drawing on Patriotism

"[We] remind the industry that it is in the nation's best interest and the industry's interest to keep gas flowing and deliverable when and where needed and . not unreasonably inhibit the meeting of gas purchasers and gas sellers in a competitive market" [Order No 636, p 96]

From Virtue to Vice

"[The] pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry this harm has an unreasonable impact on gas sellers and is an unlawful restraint of trade" [Order No 636, p 39]

To Level the Field

"Pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors" [Order No 636, p 32] reflect the prevailing operating conditions on the pipeline

I'm not advocating a different price for every hour of the year on every different section of the line But I am advocating that the industry get far away from the idea that "one rate fits all" The nature of a competitive market place allows for some tailoring and customizing of individual prices and contract terms Indeed, if the market doesn't exhibit these characteristics at all, then it's not really a competitive market Customizing may be one way to develop a "no-notice" competitive transportation market There's certainly room for this market considering that interruptible transportation now accounts for 51 percent of pipeline deliveries to market

Tailored rate designs ought to reflect a match between the customers needs, the producer's supply, and the pipeline's operating conditions This brings me back to my emphasis on the need for good information More than ever before, there will be an emphasis on the optimal scheduling of pipeline flows, storage, maintenance, controlling, and shifting consumer demand In this situation command and control of information is paramount because a competitive market inevitably reduces profit margins for the poorly organized and inefficient party To be effective negotiators, gas purchasers and sellers must have the ability to recognize and act on the opportunities offered by the ebb and flow of a pipeline's operating conditions FERC clearly understands this and accordingly has decided to make pipeline operations an open book for both gas buyers and sellers

I hope LDCs and their customers are ready for the responsibilities of a competitive natural gas market The LDCs fit the national pattern already noted by the FERC Buying a lot of gas on the spot market, using interruptible transportation, and relying on pipeline sales for peak-day purchases, while keeping overall bills below the potential cost of exclusive reliance on pipeline gas The LDCs have had an extended learning opportunity It's up to them to take this experience and skillfully apply it the emerging market that the FERC is now creating

The competitive market certainly raises uncertainties at the federal and state levels How will the FERC draw the boundary between proprietary information and information required to make the market competitive? How does state regulation establish risk-sharing between the core customers and an LDC making a gas purchase on their behalf? Will a purchased gas adjustment (PGA) clause continue to serve a useful purpose once pipelines comply with Order 636?

These questions don't exhaust the possibilities, but sooner or later, perhaps in a rate case setting or in a notice of inquiry, the LDCs will have to show their state regulatory body that they've read the open book on pipeline operations and made good use of it This would serve everyone's interest, and the LDCs should avoid putting truth to old sayings "You can lead a horse to water but you can't make it drink," or, in the case of pipeline operations, "seeing a book open does not make its reader think"

Order 636-A: A Short-term Solution?

On July 30 the FERC met and voted to approve Order No 636-A, in which it slightly relaxed its effort to push the natural gas industry into the information age Pipeline capacity released for less than one calendar month will now require neither advanced posting on electronic bulletin boards nor bidding

But the practicality of omitting short-term transactions from posting and bidding requirements will diminish as the industry learns better how to handle transactions of various sizes and duration These short-term events cause a nuisance only when the players in the market are not ready to use or interpret the information that they provide Any competitive market features short-term, low-volume transactions, and there is no inherent reason why such transactions should hinder a competitive market in its allocative efficiency Thus, we can likely expect that the FERC will eventually withdraw Order 636-A and replace it in a subsequent rule making

Competition Versus Reliability

The importance of pipeline operations cannot be overstated because major changes in public policy towards regulated industry are constrained by technical considerations The FERC's restructuring efforts are no exception At the inception of the "Mega-NOPR," pipeline system reliability was incompatible with competition — one condition precluded the other With the industry's help, the FERC resolved this apparent contradiction and found that system reliability and competition coexist Neither one preempts the other

With a little imagination, the FERC might apply this reasoning to the issue of transmission access in the electric power industry All that's needed is to substitute "electric utility" for "pipeline" and "no-notice transmission" for "no-notice transportation" Can the FERC make competition in the electric industry compatible with system reliability? Perhaps not, but the electric industry may soon be hard pressed to explain why system reliability and competition cannot coexist in the power industry

The FERC has offered a number of individual steps that, if taken quickly and cooperatively, will speed the gas industry's adoption of competitive market practices But I emphasize the *fragility* of the FERC's proposal and the need for cooperation to make the system work Hot new designer rates won't sell in the market place if the players torpedo the restructuring I agree with the unspoken sentiment expressed by the FERC Restructuring the industry will work only if the players adopt the spirit of "cooperative competition" That should characterize all bargaining between sellers, buyers, and pipelines

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The opinions expressed here do not necessarily represent those of the Iowa Utilities Board

Vol 110 No 12

A Strategic Perspective on Small-Scale Package Cogeneration

By STEPHEN N BROWN*

This article suggests action which electric utilities should take to protect themselves against erosion of revenues and sales volumes caused by advancing development of small-scale cogeneration packages The strategy proposed is one of incremental pricing of utility power to potential cogenerators to reduce their incentive to choose small-scale cogeneration The economic feasibility of cogeneration of this kind, he asserts, is created by utility adherence to average embedded cost pricing policies

Small-scale package cogeneration is quickly gaining preference over electric utility generation among smaller commercial customers needing electricity and thermal energy Presently, there are forecasts for 40,000 package cogeneration installations by the year 2000 with a gross investment of $63 billion [1]** Lower capital and fuel costs account for the attractiveness of package cogeneration plant, which will have several major effects on electric utilities The following discussion is subdivided into three sections The first describes the markets targeted by the package cogeneration developers as well as their marketing strategy and competitive advantages, the second enumerates and specifies the problems that the packages will create for utilities, and the final section provides a competitive pricing policy for electric utilities that meets the package cogeneration challenge

*The opinions expressed herein are those of the author and not necessarily those of any employer, past or present

**Numbers in brackets correspond to references listed at the end of the article

Stephen N. Brown was supervisor of rate design in the rate and research department at Houston Lighting and Power Company when this article was written Since then he has accepted a position as director of the conservation auditing and research division at the Iowa State Commerce Commission in Des Moines He has published articles on the applications of bubble memory and fiber-optic technologies in the utility industry and on rate design issues **Dr. Brown** received his MS degree in regulatory economics from the University of Wyoming and his PhD degree from the University of Denver

Markets and Selling Points

Cogeneration is usually associated with large industrial customers that have distillate processes, such as chemical or petroleum operations where a high proportion of electricity is generated along with thermal output electrical output ranges from five to a few hundred megawatts, customers are most often directly tied into the utility's transmission system, and the electrical output is intended for sale to the local utility The small-scale packages differ markedly from industrial cogeneration the electrical output ranges from 60 kilowatts to one megawatt, the customers are tied to the utility's distribution system, and the electrical output is not intended for sale to the utility, but as a substitute for electrical purchases from the utility

Different kinds of customers have a dual need for heat and electricity hospitals, nursing homes, colleges and universities, primary and secondary schools, large apartment buildings and other multifamily housing, small-scale manufacturing, institutional laundry facilities, and 24-hour service outlets like grocery or fast-food chain stores A new source of cogeneration growth is the next generation of commercial office buildings, which are being designed to be as independent as possible from local utilities These customers usually represent a significant portion of the nonresidential distribution load on any utility customers exercise the package cogeneration ties will face difficult problems Most of the ilities are not intended to be independent of electrical system, when they require mainte- ·ak down unexpectedly, the utility automat- up the customer's electric load In so doing, provides an "insurance" function to the pack- rators The value of the insurance function tomer varies depending on factors like the ay or time of year when the cogeneration

rics of attaching a proper price to this func- it no small task even if only a handful of systems are involved, but when the utility faces 0 of these on the electrical system, the need pricing is readily apparent Yet electric utili- ularly those with large construction programs, ford a shrinking sales volume, they can, how- n er cogeneration's impact on sales revenues ig prices and contract terms that preserve their ket and offset the advantages that the small- enerators now have

ost important advantage of small-scale pack- neration is its apparent cost-effectiveness for user Electricity acquired through cogeneration s less expensive than electricity purchased from utility This creates savings generally split be- e end user and the developer of the cogeneration

Typically, the developer installs the system ns ownership by leasing the cogeneration equip- the end user for five years A contract with a arty provides for maintenance The end user no capital outlay, thereby avoiding nearly all ociated with the cogeneration project

are other advantages for the developers By g ownership the developers retain tax write-offs depreciation — an aspect that may not be im- to the end user Also, the cogeneration plant is epreciated in five years, a much shorter period central station generation plant typically depre- over thirty years on a straight-line basis This hts an even more important aspect of the pack- ncept The developers are able to recover their d capital in a short time This quick recovery of l and the profits made through leasing arrange- are sufficient motivation to establish a nation- sales and service network and to re-invest in more ologically advanced and reliable machinery as time

se advantages are strengthened by federal tax re- that eliminates or reduces investment tax credits accelerated depreciation for major capital invest- s by electric utilities Also, end users who can take ntage of the cogeneration packages will also be to meet their own load growth by adding addi- l small-scale units rather than by increasing pur- chases from the utility Without corrective action by the electric utilities the package cogeneration systems will be a self-perpetuating phenomenon causing a permanent loss of sales to the electric industry

A sizeable beneficiary of the shift towards small-scale cogeneration is the natural gas industry because it will be the largest supplier of fuel to the package systems In fact, natural gas prices for cogenerators are discounted as much as 25 per cent from normal consumer prices [2] However, if 40,000 installations are actually operating in the year 2000, there will be a definite effect on the need for additional capacity in the local natural gas distribution systems, and this will certainly increase the cost of natural gas to the package cogenerators Local gas distributors may resist such expansion unless they are guaranteed swift recovery of their capital outlays

There is no question that the package product has a sound supply base Fueled by natural gas (or the less preferred diesel fuel), the systems use reciprocating engines, internal combustion machines widely available from such well-known manufacturers as Caterpillar, Cummins-Diesel, Minneapolis-Moline, and others All of the package's mechanical parts are easily serviced and readily available

The Utility's Perspective

These systems are an ideal profit vehicle for a developer, but the electric utility industry has to view package cogeneration in a larger and different perspective This perspective includes the following elements

No Reduced Commitment to Serve Although the package's electrical output is meant to be a substitute for electrical purchases from the local utility, this does not mean that the cogeneration system is independent from the utility's electrical system The package systems relying on an induction generator must have a *source* of voltage, the electric utility The generator is set up to parallel the utility's system automatically, i e , the generator's voltage is automatically equal in phase and magnitude to the utility's Cogeneration packages based on an induction generator continue to be utility-dependent

The alternative to an induction machine is a synchronous one capable of independent operation but more costly and complicated because specific controls and protective devices are required to make the machine's electrical characteristics match those of the electric utility The induction generator is more compatible with the prevailing electrical system, thereby allowing the package's developer to maintain a higher profit level

Congestion Problems and Monitoring Needs The physical locations of the package systems are likely to follow the same pattern as business locations The safety problems associated with small cogeneration are well known, but they may be more difficult to solve or recognize as the market grows If several cogenerators are connected to the same distribution line, then an electrical problem caused by one may affect the others Hospitals or manufacturing facilities that locate in close proximity to one another are good examples The small cogenerating plants will have to be monitored continually to pinpoint the source of such problems This means an expansion of the utility's internal communications network and the incurrence of additional expense

Reduction in Distribution Capacity Available for Load Growth Distribution planners must size primary and secondary electric lines as well as transformers to meet a certain demand level Should this level include the demand caused by failed cogeneration machines? Who pays for the incremental investment necessary to meet such a demand? This is a cost allocation problem, but it underscores an important point Distribution capacity that was once built for generic load growth will be absorbed by distribution level cogenerators

· *Disruption of Competitive Markets in Wholesale Power Supply* A principal way to move the industry towards a competitive position in bulk power supply is to eliminate the vertical integration of the electric utility by separating its generation and transmission functions from the distribution function The distribution function would become an independent retail company with a franchised monopoly seeking a wholesale power supply, the generation and transmission functions would become an independent wholesale company seeking buyers of wholesale power The retail and wholesale companies would be free to choose their partners and to negotiate contract terms

Yet when a distribution company is free to find its own wholesale power supplier, a proliferation of small distribution-level cogenerators could weaken the distribution company's ability to control its own load and hamper contract negotiations with the wholesale supplier This is particularly true if the wholesale company, in entering a contract with a buyer, is obligated to purchase or market electrical output provided by small cogenerators within the retail company's service territory The Federal Energy Regulatory Commission last year established this principle in a ruling concerning the Oglethorpe Power Corporation, a wholesale generation and transmission organization The FERC ruled that Oglethorpe must purchase power from cogenerators within the retail distributors' service territory [3]

In a competitive market, the wholesale power company will be reluctant to do business with such a retail distributor because the wholesale supplier must absorb such costs or pass them on in some form to other retail outlets Retail distributors without cogenerators would seek protection from these costs or find a different wholesale power supplier Applying the FERC's principle as a general rule would retard the movement towards a separation of functions, reinforce the integrated nature of the utility, and retard movement towards a more competitive wholesale power industry [4]

Competitive Pricing Policy Is Correct Response for Utilities

By offering incremental prices to potential package cogenerators, a utility can eliminate the customer's incentive to choose small-scale cogeneration Moreover an incremental pricing policy should be developed and offered before the customer becomes a cogenerator Continuing to price power on the basis of average embedded cost will only hasten the spread of the package systems Prices derived from an incremental approach will be low enough to compete and below average embedded prices [5]

Once a customer has made the conversion to cogeneration there is no effective way for the utility to recover its revenue loss Although cogenerators are not independent of the utility and must purchase its power when their package systems break down, such purchases do not provide an opportunity for the utility to recover its revenues If the utility recaptured these revenues, it would fully negate the savings created by the cogeneration project and destroy its economic feasibility This is not possible because cogeneration proponents have already established the position that their power purchases are different from the power purchases of other customers Cogenerators categorize their purchases as maintenance, backup, and supplemental power

When a cogenerator buys electricity because the cogeneration plant is out of service for scheduled maintenance, the purchase is classified as maintenance power. When the maintenance is either not scheduled or the result of an unexpected breakdown, the purchase is classified as backup power When the cogeneration plant is operating normally but supplies less than 100 per cent of the customer's need, the purchase is classified as supplemental power

Cogenerators view supplemental power as no different than that provided by the utility to ... requirements customer and maintain that prices and contract terms that apply to normal services should also apply to supplemental power However, supplemental purchases give no comfort to the utility because they are only a fraction of the sales volume lost to package systems

Cogenerators argue that maintenance and backup power are commodities distinct from and cheaper than the utility's normal services, that contract terms should be less stringent than those applied to other customers, and that the prices for these two types of power should be less than those applied to normal services The concept of maintenance power gives little consideration to the complexities of a utility coordinating scheduled cogeneration outages for numerous package systems

ɔt comparable to a handful of industrial
rs scheduling their outages Also, the need
ı power requires the utility to reserve capac-
ı the package cogenerator's load
ıhese observations, the effect of the cogenera-
gy is to thwart any utility's attempt to recap-
revenues A utility could offer power to a
ɔr on the basis of prices weighted towards
ıour charges or demand charges If the former
ıen a utility's revenue recovery will be mini-
ıse the longer the package machine runs, the
watt-hours are displaced from the utility If
applies, then revenue recovery will be sub-
ınd probably cause cogenerators to appeal to
y authorities for aid
ample, if a customer's normal demand level is
watts for each hour in a 730-hour month, then
thly kilowatt-hour purchases from the utility
ɔı A package cogeneration machine providing
watts each hour reduces purchases by 73,000
-hours For each hour that the machine did not
ılowatt-hour purchases would increase by only
ıces weighted towards a kilowatt-hour charge
no protection for the utility's sales or revenues
unlikely to cause strenuous protest by cogen-
When a demand charge is the most important
ıe cogenerator's savings depend on the time of
chase, the demand level established on the utili-
tem at that time, and whether the demand level
ıeted
ınuing with this example, if a particular cogen-
machine did not operate for a particular hour
ven month, then the customer establishes a de-
evel of 110 kilowatts on the utility's system The
vill be higher in a peak period than in an off-
ıeriod In addition, if the demand charge contains
ıual ratchet provision, then the customer will have
for the 110 kilowatts or a portion of it during
ıf the next twelve months Attaching a high price
nand quantities forces the cogenerator's savings
owards zero and maximizes the utility's revenue
ery
uch circumstances, backup and maintenance power
ıe very important and a point of contention be-
the cogenerator and the utility A recent FERC
ıvolving a cogenerator leasing rather than owning
erating equipment illustrates this A pharmaceuti-
anufacturer in Puerto Rico, Alcon Inc, leased
eration equipment from O'Brien Energy Products,
RC ruled that Alcon had no ownership interest in
ɔgeneration equipment and was not entitled to
ɔ power But one FERC commissioner dissented
he majority opinion and suggested that the denial
kup power to Alcon was an abuse, stating "the
ıce of backup power is fundamental to deci-
ɔ self-generate" regardless of whether the cogenerator intends to sell power to the local utility [3] Although resolved in favor of a local electric utility, the case is not a trustworthy precedent for the industry as a whole and does not provide market protection The dissenting commissioner's opinion might prevail in a future case and have far-reaching consequences by establishing the precedent that the assurance of backup power *at reasonable prices and contract conditions* is fundamental to decisions to self-generate The best market protection is a speedy application of well-conceived pricing policies before additional precedents are set

The economic feasibility of small-scale cogeneration is created by the policy of average embedded pricing, a policy reflecting old technology and preserving the advantages of package facilities that enjoy much quicker write-offs than utilities, and therefore, greater incentives to apply technological advances to small-scale cogeneration plants Such a pricing policy also ignores the pervasive economies of scale that are inherent in the central station generation of electricity This is particularly true for a utility bringing new plants into the rate base [5]

The market penetration strategy of the package's producers is aimed at areas served by the new plants and is predicated on the assumption that the new plants will drive up prices so much that the electric customers will logically select the cogeneration option Successful implementation depends on the utility's inability to price its product incrementally However, a utility expects the demand for its services to grow through time, and a newly constructed plant typically achieves its lowest-cost output for an output level reached at sometime in the future, not at the moment the new plant is operational In this case the utility's plant or collection of plants produces output at less than the level which minimizes average cost

The favored tax write-offs as well as the availability of low-priced natural gas for cogenerators undoubtedly make them a preferred alternative to the electric utility, but when facing a situation of retaining or losing a customer's business, the utility should not turn away the sale when it recovers the incremental cost of power sold Effective competition and economic efficiency require incremental rates at the distribution level to meet the package cogeneration challenge

This policy cannot be characterized as internal subsidy by some who may claim that the utility's other consumers provide high profit margins to subsidize lower rates in the competitive market The utility's rate of return in this market will be less than system average, but as long as the incremental cost is met, the utility is better off than not making the sale at all Utilities have heavy fixed costs that are free from inflationary spirals and ample capacity when new plants become operational This competitive advantage must be fully exploited

The package cogeneration plant uses variable factors to a large extent, has quick write-offs, and is neither vertically nor horizontally integrated It will also be subject to price increases through increasing capital costs in future inflationary periods In the long run, there is no question that utilities would prevail in the openly competitive marketplace

Conclusion

There are a number of hidden costs associated with small-scale package cogeneration, it is not the boon to consumers that it is touted to be In heavy concentrations the package systems are an untested and potentially disruptive factor that should not be accepted as a step towards a competitive and more efficient market until all the hidden costs are known and incorporated into its price

Utilities faced with an influx of small-scale cogenerators should offer incremental pricing at the distribution level to protect revenues and sales volumes Appealing to a regulatory body for such protection is not practical because the time involved in making a ruling may be considerable and there is no certainty that the ruling would be a favorable one While some members of the electric industry may find an incremental pricing approach unacceptable, it is preferable to leaving the field and letting other ratepayers or stockholders pay for the revenue erosion

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Growth in Demand for Convenient Goods and Services Forecast

U S households will become wealthier and busier over the next decade, leading many consumers to pay a premium for products and services that will free them from everyday household chores, predicts Stanley Buchin, a senior vice president with Temple, Barker & Sloane, Inc , general management consultants based in Lexington, Massachusetts

Economic trends, changing life-styles, and developing technologies will alter the basic composition of the U S household, which in turn will influence the marketing strategies of many companies The next decade will see a wave of prosperity, with steady but moderate economic growth and moderate inflation and unemployment

Buchin, who directs TBS's marketing management consulting practice, noted that the more affluent consumers of 1995 will consist primarily of two-career, husband-and-wife households and single-person households Nearly three-fourths of all households will *not* have a full-time homemaker "Tomorrow's consumers will seek convenience in products and services and will be willing to pay a premium for it," he stated

According to Buchin, the drive for convenience will create a large market for "smart" household appliances that rely on sensors and microprocessors "Consumers will program ovens to defrost, brown, and heat food so that dinner can be ready at a precise, planned time," he said, adding that "we may even see some households using programmable robots to assist with such chores as home cleaning "

MONEY & INVESTING

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Natural-Gas Prices Thrown in Doubt

By Chip Cummins

It's another unsavory secret that many in the energy-business long knew, but others only suspected: Traders don't always tell the truth when volunteering information about natural-gas prices.

Now, in the wake of revelations about false price reporting, regulators are investigating how long the deception went on, how widespread it was and how much it might actually have corrupted actual market prices.

Depending on what they find, it could further taint the image of the energy business, which is reeling from disclosures of widespread bogus trading in both gas and electricity markets.

In recent weeks, a handful of energy companies have disclosed their traders provided inaccurate data to independent publishers of natural-gas price indexes. The indexes are used by a large swath of industrial America to price wholesale gas—an important fuel for power plants and an essential ingredient in chemicals and steel making. Index publishers say that they have systems in place to screen bogus numbers and that they don't believe their products have been affected.

While the impact on actual prices still isn't known, the revelations confirmed years of suspicions by gas producers and commercial users, and have thrown a spotlight on an otherwise obscure method for valuing billions of dollars of energy deals. The prices reported by traders are the raw data that determine movements in the indexes, just as share prices are the raw data for stock market indexes.

"Does it concern us? Of course," says Pat Durkin, director of gas supply at Philadelphia Gas Works, the country's largest municipal-owned gas utility, adding, "we've depended on these for a very long time." He notes he still has faith in the indexes, but is seeing other players abandon them, wary they may not reflect the best market prices.

Many other energy markets use similar indexes to price everything from coal to petroleum products such as gasoline. The gas-index disclosures have some analysts worried that confidence and price transparency in those markets may also be affected if more companies admit to providing false information.

Details of the false reporting haven't been made public. But traders could have had incentive to try to

Please Turn to Page C12, Column 3

Pricing Energy

Participants in wholesale natural-gas markets, and a host of other commodity markets, price long-term contracts a number of ways:

	PLUSES	MINUSES
INDEXES Independent publishers survey buyers and sellers, compile benchmark indexes and distribute them to subscribers	With many indexes available, players can pick and choose those best suited for their region	Price data are generally provided voluntarily and aren't subject to rigid audits
FUTURES Players can base contracts on prices of futures, traded on exchanges like the New York Mercantile Exchange.	Trading in underlying futures contract is closely supervised by the exchanges and outside regulators	Limited number of futures contracts
FIXED CONTRACTS Buyers and sellers agree between themselves on fixed prices, which don't fluctuate for the term of the contract.	Prices aren't subject to changing index or exchange prices	By locking in a price, a buyer or seller may get burned if markets move against them

Iraq War . Add to Re By Market

Blue Chips, Nasdaq F Investors Seek Retail- And Comments From

By E S Brown

Nervousness about with Iraq and about e out later this week fu stock pullback, as the Veterans some investors on the sidelines

The Dow Jones Industrial Av 178 18 points, to 8358 95, its se than 2% in the three trading days Wednesday of last week It is d three days and is down 17% sin

The most immediate obstacle was the prospect of war Membe ment condemned the U N res- olution calling on Iraq to agree by Friday to unfettered weapons inspections, but some political analysts took that as saber-rattling rather than

On top of that, investors aw Congress by Federal Reserve Greenspan tomorrow, news ab sales, due Thursday, and inc

A DR Drop May Signal U.S. Appeal Is Fading

FUTURES

Traders' Gas-Price Data Are Getting Closer Look

Continued From Page C1

make money by influencing gas prices in both directions, and thus misreporting prices on either the high side or the low side Higher gas prices would have allowed them to book higher profits on straight-forward contracts for gas delivery At the same time, a trader's company might also benefit from lower prices if its overall trading "book"—all of its transactions taken together—was geared toward benefiting from spreads between falling gas, for instance, and rising electricity prices.

The natural-gas indexes are important to a smoothly functioning market because trading of gas is so fragmented, with prices varying in different regions Despite concerns about the false reporting, one problem facing buyers, sellers and users of gas is there are few alternatives to indexes for determining whether they are getting a fair price.

'Henry Hub'

Sophisticated players can negotiate rates based on actual bids and offers each day, and others can sign long-term, fixed-price contracts. Many players price contracts off futures at the New York Mercantile Exchange But those prices reflect the market at just one delivery hub in Louisiana, called "Henry Hub" In other parts of the country, gas prices can fluctuate widely from that benchmark, depending on regional supply and demand. Earlier this month, for instance, when spot prices at Henry Hub were just above $4 per million British thermal units, prices at hubs in the Rocky Mountains were as much as $1 lower.

That's where indexes come in A number of publishers survey buyers and sellers at various delivery points across the country and in Canada Leading publishers, including the Platts unit of **McGraw-Hill Cos**, solicit voluntary pricing data from hundreds of players and distribute daily and monthly price benchmarks to subscribers. About 20% of the $230 million daily physical gas market is priced on one index or another, says Jeff Dietert, an analyst at Simmons & Co in Houston

For many gas buyers, the indexes are "the only act in town," says Bob Cave, president of the American Public Gas Association, a trade group of gas-distribution companies "The devil you know is better than the devil you don't know"

Dynegy Inc started the snowball of disclosures, saying in late September that employees were found during an internal probe to have provided bad data to several publications **American Electric Power Co**, **CMS Energy Corp** and **Williams Cos.** followed AEP and Dynegy have fired employees allegedly involved, while CMS Energy and Williams are conducting internal probes

Regulators, including the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission, are investigating the scope of false reporting to indexes FERC, in an August staff report, found gas and electricity indexes "susceptible" to price manipulation Until recent disclosures, however, there hadn't been any real evidence

Regulators were initially interested in finding out whether companies tried to manipulate prices by reporting "wash" trades—essentially mirror-image sales of energy, which cancel each other out Wash trades appear to be another widely condoned practice in energy trading under broad investigation More recent subpoenas and information requests are geared toward finding out whether traders simply exaggerated or made up data they submitted to the indexes

Companies say they are cooperating with investigators, but they haven't provided much detail in public disclosures, refusing to release information such as when traders provided the data AEP, which fired five traders last month, has gone the furthest in disclosures so far It has said traders provided bad data to Platts and other publishers that involved transactions at the same Louisiana trading hub where Nymex bases its contract.

Some market analysts say wholesale gas markets are too large and liquid for any one company to have a real effect But many indexes gauge prices at smaller, relatively illiquid delivery points, making manipulation easier By providing incorrect data—like prices or volumes—traders could move the index and possibly the broader market to favor their own trading positions

Clamoring for an Overhaul

A number of market players are clamoring for an overhaul The gas association's Mr Cave has been petitioning Congress, FERC and the Energy Department to look at the problem **Apache Corp**, a large Houston gas producer, is calling for a federally mandated price-reporting system with auditing and penalties for false reporting "Under the present system, it just doesn't work," says Tony Lentini, an Apache spokesman.

But some analysts say regulation is a bad idea and price indexes—though not perfect—are working relatively well Philip K Verleger, a senior fellow at the New York-based Council on Foreign Relations, worries that an overblown reaction may reduce price transparency in all sorts of energy arenas, including international oil markets Dr Verleger says a competitive market for price reporting itself already keeps publishers working hard to improve their procedures and ensure accurate prices.

"Market transparency is incredibly important," says Dr Verleger, who also consults for marketers such as Dynegy "If you criminalize exaggeration, people aren't going to report at all People will stop talking."

Many companies are clamming up, while others have tightened reporting and oversight **Exxon Mobil Corp** and Coral Energy, a unit of **Royal Dutch/Shell Group**, both have restricted traders from providing data to index publishers for a wide array of commodities Instead, the two companies will submit prices to publishers in consolidated reports.

More Information About Trades

The publishers are also revising their methodology, even as many of the country's largest marketers bow out of energy trading altogether, drying up volumes at many delivery points and making index compilations even more difficult Starting next year, Platts will require more information from companies about their trades and will require price reports to be certified by a company's chief risk officer. Dow Jones Newswires, a unit of **Dow Jones & Co**, the publisher of The Wall Street Journal, doesn't compile domestic gas indexes, but it does publish electricity indexes It doesn't plan any changes to its procedures, though it requires formalized arrangements with companies providing prices, including a provision allowing Dow Jones to audit the data

Meanwhile, in commodity trading yesterday

SOYBEAN OIL & SOYBEANS. Commodity fund buying and reports that India, a major oilseed-producing country, would harvest a smaller crop lifted soybean-oil contracts at the Chicago Board of Trade. That, in turn, gave soybeans a boost, scoring double-digit gains December soybean oil rose 0.70 cent to 22.66 cents a pound, just one cent shy of the contract high it set late in the session January soybeans climbed 9 75 cents to $5 6825 a bushel

CRUDE OIL: New York Mercantile Exchange prices gained moderately, as a rally sparked by bellicose comments from a senior Iraqi lawmaker ran out of steam. The December contract rose 16 cents to $25 94 a barrel, having earlier risen to a high of $26.50 The early rally came after the head of the Iraqi parliament's foreign-relations committee said Iraq should reject a new United Nations resolution on weapons inspections

LUMBER. Prices fell on the Chicago Mercantile Exchange, reflecting a slow cash market. The January contract dropped $6.80 to $223 50 a thousand board feet and set a contract low of $220 30.

—*Debbie Carlson*
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