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# WHO PAYS FOR SUNK COSTS?

by

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## EXECUTIVE SUMMARY

Competition is spreading into many markets formerly served by utility monopolies. As a result, utility regulators are increasingly having to deal with the causes and effects of utilities' loss of business to competitors. When customers respond to uncompetitive utility rates by taking service from the utility's competitors, the result may be unused, or excess, utility capacity. The "sunk", or already incurred, cost of that unused capacity, as well as other similar sunk costs, must be borne by remaining customers, former customers, or utility stockholders. Regulators are having to decide who pays.

The issue of who pays for certain competitively-induced excess capacity costs has been resolved in a number of rate cases in the natural gas and electric utility industries. Many FERC-regulated pipelines have sustained large sales losses because they have attempted to recover uncompetitive cost levels in the face of an expanding array of competitive alternatives to pipeline sales, such as transportation, conservation, and alternative fuels. In several cases in recent years, the FERC has assigned some of the cost of unused pipeline capacity to stockholders. The FERC has done this by imputing a "reasonable" pipeline throughput level which may be greater than the current actual or projected throughput. If the pipeline is subsequently unable to achieve throughput equal to the imputed level, fixed costs assigned to the unrealized volumes will not be recovered.

At the state commission level, electric and natural gas cases dealing with "incentive" or "cogeneration deferral" industrial rate discounts have been the most frequent venue for determining ratepayer-stockholder allocations of competitively-induced uneconomic sunk costs. In most of these cases, the utility's attempts to recover excess sunk costs have made competitive alternatives more attractive to industrial customers, leading to actual or threatened loss of utility sales. Utilities and regulators have responded by attempting to preserve or increase utility sales by allowing rate discounts for price-elastic industrial customers who maintain or increase loads. Such discounted rates generally recover at least the short-run incremental costs of service, but fail to recover the full long-run marginal cost of service, which includes capacity costs. These discounts raise the issue of whether other ratepayers should make up the revenues foregone because of the discount, or whether utility stockholders should absorb the discount through lower earnings.

Regulators have varied widely in their decisions as to who pays for industrial rate discounts, but most commissions have required shareholders to absorb at least part of the revenue loss. This has been accomplished, initially, by the general ratemaking practice of assigning to stockholders the risk of sales fluctuations between general rate cases. However, some commissions have further increased stockholder responsibility by imputing some or all of the discount as revenues for ratemaking purposes in general rate cases. Such imputations, by not permitting the utility's overall rate level to recover its full embedded cost of service, are effectively equivalent to disallowing a portion of the excessive costs that damaged or threatened the utility's competitive posture.

The regulatory treatment of unused utility capacity usually involves application of the "prudent investment" or "used-and-useful" standards. While there is little dispute that imprudently incurred excess capacity costs should not be charged to customers, utilities have often lost sales to competitors for reasons other than demonstrable management imprudence. Many utilities in recent years have made seemingly prudent decisions to incur costs that later turned out to be grossly in excess of competitors' costs. When the resulting uncompetitive utility rates create excess capacity, regulators must decide whether the prudently incurred costs of the excess capacity should be disallowed (charged to stockholders), recovered by increasing rates to remaining ratepayers, or somehow charged to departed customers.

Proposals to disallow prudently incurred costs of excess capacity are usually cast in terms of applying a "used-and-useful" standard that prevents utilities from recovering the cost of idled plant. Since competitive, unregulated markets do not permit firms to recover costs of excess capacity, prudently incurred or not, the used-and-useful standard is intended to simulate competitive market conditions in the regulated utility sector. Assigning the risk of competitively-induced sales losses to stockholders enhances their incentive to maintain efficient utility operations as the means to avoid loss of sales to competitors and consequent financial losses to themselves.

Advocates of the "prudent investment" standard counter with the claim that "prudent" decisions--i.e., decisions reasonable at the time and under the circumstances the decisions were made--are the most that can be expected of utility management. Disallowances of any prudently incurred costs made on the basis of hindsight, according to this view, violate the "regulatory compact" under which utilities forego the potential to earn above-average returns in exchange for a reasonable opportunity to recover all prudently incurred costs. Defenders of the "prudent investment" standard contend that disallowing prudently incurred costs is inequitable to stockholders and jeopardizes their continued willingness to supply capital on reasonable terms.

For utilities with competitively-induced excess capacity, recovering "prudently" incurred uneconomic costs may be easier said than done. If the utility increases rates to remaining customers, that may simply stimulate more sales erosion, worsening the excess capacity problem. This difficulty has led to proposals for "exit fees", purchase-deficiency based direct-billing, and similar mechanisms designed to charge excess capacity costs or other uneconomic sunk costs to customers who have reduced usage or departed the utility system. For example, the FERC has permitted pipelines to directly-bill a portion of their excess gas supply costs to customers who have reduced or eliminated usage.

Exit-fee type measures, however, have not yet gained widespread acceptance. They have been criticized as attempts to frustrate pro-competitive policies by insulating investors from the risk that customers will respond to high prices or poor service by curtailing purchases. They may also be subject to legal and regulatory policy prohibitions against retroactive ratemaking, where they amount to attempts to charge customers for utility costs incurred in the past.

A proper resolution of the competing claims made for the prudent investment and used-and-useful standards must involve an analysis of the impact of alternative policies on the cost and availability of capital. Although both theory and evidence indicate that assigning excess capacity risks to stockholders will result in higher capital costs than would exist if ratepayers bear the risk, that does not compel the conclusion that such risks should be fully assigned to ratepayers. The benefits to ratepayers of forbidding recovery of inefficiently incurred costs, including enhanced utility management efficiency and protection from potentially large excess cost burdens, will likely more than offset the rate impacts of increased capital costs.

Regulators frequently attempt to balance the policy concerns underlying the prudent investment and used-and-useful standards by a policy that "shares" the cost of excess capacity (and other uneconomic sunk costs) between ratepayers and stockholders. While a "sharing" policy attempts to be fair to both sides, and is not necessarily wrong, optimal policymaking will avoid an overly arbitrary "split the difference" approach. The ratepayer-stockholder allocation of responsibility for competitively-induced excess capacity costs should be reasonably related to the cause of the utility's loss of business.

For utilities whose sales erode because their rates have been increased to uncompetitive levels in the attempt to recover inefficiently incurred costs (whether or not imprudence was a factor), most or all inefficiently incurred costs, including any excess capacity costs, should be absorbed by stockholders. Such a policy will both protect ratepayers and enhance economic efficiency by giving tangible incentives to utility ownership to improve management performance.

Economically unsound rate design policies can artificially overprice services and depress sales even for efficient utilities. Where faulty rate design results in a loss of business and inadequate earnings for utilities, rate design should be corrected to permit the utility to recapture lost business. Under rate design reform of this sort, no overall rate increase to customers nor any further stockholder financial loss need result.

The proper regulatory response is not as clear-cut in the less frequently observed circumstance of "economic bypass", where competitors capture formerly utility business because of technological advantages, rather than utility inefficiency or faulty rate design. The ratepayer-stockholder allocation of excess capacity costs resulting from economic bypass should be based on a case-specific analysis encompassing economic and equity concerns. A suggested reasonable approach would be to allocate such excess capacity costs equally between ratepayers and stockholders, although a larger allocation to stockholders would be appropriate where competitive conditions would unduly constrain the ability to raise rates. For a utility whose competitive posture more readily permits rate increases, a larger than fifty percent customer allocation of excess capacity costs resulting from economic bypass may be reasonable.

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## FOREWORD

The question of who pays for sunk costs of utility plant that is unused or underused is increasingly before regulatory commissions. Accordingly, our Board of Directors in early 1988 asked that we produce a report on this topic covering the electric, gas, and telecommunications sectors. We contracted for the study in the spring and now are publishing the results. I commend this balanced report to your attention.

Douglas N. Jones
Director, NRRI
Columbus, Ohio

August 1988

## 1. INTRODUCTION

Who pays for the sunk costs of abandoned, unused or underused utility plant has become a major issue for many public utility regulators. Technological and economic trends, especially those influenced by new public policies to promote competition, have combined to erode markets and alter expected demands for various utility services in recent years. This is now forcing regulators to consider who should pay for the economic consequences of unused capacity and sunk costs, especially in situations where newly imposed competitive policies are a root cause. AT&T's 1985 write-off of half a billion dollars worth of unrecoverable obsolescent terminal equipment costs was an early indication of the potential magnitude of the costs involved, but that write-off has more recently been dwarfed by the billions of dollars in sunk costs incurred by interstate pipelines for buy-outs of take-or-pay liabilities, and the even larger sums that some electric utilities have sunk in excess capacity and abandoned plants.

These uneconomic costs have been the product of complex forces, including inflation, competition, and inaccurate (although not necessarily imprudent) market forecasting and capacity planning. Concerns that utility customers might "bypass" utility systems to obtain service from competitors, first voiced in the telephone industry, have proven to be an even larger and more immediate problem for some electric and gas utilities, many of whom are now scrambling to preserve their markets in the face of fuel substitution, open access transportation policies, changing local economies, and demand reductions brought about by their own higher costs of providing service. PURPA incentives for the development of competitive (and often more economic) electric generation capacity (cogeneration and small-power production), FERC policies encouraging gas transportation rather than full requirements service and FCC policies supporting equal network access for new telecommunications vendors have displaced or threatened to displace a portion of the market (or market growth) that was traditionally assured for the utility monopoly in virtually all states.

Utilities have proposed dealing with uneconomic sunk costs through such measures as "exit fees", purchase deficiency-based direct-billing, nonusage sensitive network access fees, economic incentive rates, charging uneconomic sunk costs to captive "core markets", and revenue deferrals. Consumers have often contended that such proposals are little more than utility attempts to saddle customers with the full burden of utility management mistakes. Many regulators, as a result, have seen such issues as cross subsidization, allocative efficiency, solvency, prudence, and equity move from the background to become the foremost regulatory issues of the day.

## 2. THE PROBLEM OF EXCESS CAPACITY

Regulators have traditionally set utility rates to recover the reasonable cost of the utility's investment in plant and equipment, but have tended not to charge customers for unreasonably overbuilt plant, or "excess capacity." Excess capacity has generally not been equated with mere unused capacity, since the latter exists even under efficient management as a reserve necessary to meet peaks or for adequate reliability, or as the result of capacity additions in relatively large, but economically efficient, increments. Unused capacity has typically been deemed "excess" where it is unreasonably large and costly owing to some culpable error of utility management.

In principle, excess capacity can result either from capacity additions designed to meet demand growth that failed to materialize, or from decreases in demand that idle existing equipment. These sources of excess capacity need not be mutually exclusive: a rate increase imposed to pay for an unnecessary plant addition can depress demand even further below the level that had been anticipated. Although, historically, it is probable that most findings of excess capacity have centered on unneeded plant additions, the more recent growth of competition in the utility sector has focused increasing attention on the potential or actual idling of existing plant. As the result of uncompetitive gas rates, many interstate pipelines and gas distribution utilities are now operating at levels far below those attained a few years ago. Electric utilities have experienced less actual erosion of capacity utilization than gas pipelines, but their projected sales growth has not materialized and many utilities have attempted to maintain and spur output levels through such devices as "cogeneration deferral" rate discounts designed to foreclose development of competitive supply sources and "incentive" rate discounts to attract and hold customers with ready access to competitive alternate energy supplies. Although "bypass" in the telecommunications industry has been more talked about than experienced, both federal and state regulators have cited the bypass "threat" as the basis for shifting more cost responsibility from toll to local exchange rates and from service related rates to customer access line charges.

When uneconomic sunk costs are incurred, regulators must decide who pays (or absorbs) the unavoidable excess amounts. Potential candidates for absorbing sunk costs include remaining customers, former customers, and utility stockholders.[1] A review of recent U. S. regulatory practice

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1 Since utility ratemaking alters the tax liabilities of utilities and some ratepayers, it is sometimes sug-

indicates that uniform treatments of these excess sunk cost issues are not followed by regulators of the electric, gas, and telecommunications industries--or even within each industry. However, except for the telecommunications industry where "premature obsolescence" and (in some cases) reduced facility usage, rather than excess capacity, has been the foremost problem, the most common policies have been some form of cost "sharing" -- i.e., policies that require stockholders and customers to share the burden of uneconomic sunk costs.[2] Such sharing is generally rationalized on the basis of equity, or as a reasonable compromise between competing policy concerns--e.g., preserving the financial stability of the utility versus consumer protection and preserving management incentives to conduct utility operations efficiently.

Lack of uniformity in this regard is not always undesirable. Different treatments of uneconomic sunk costs may be appropriate because of different circumstances. For

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gested that taxpayers are a third group (along with with ratepayers and stockholders) whose interests are significantly affected by the ratemaking process. However, as taxpayer interests are not usually considered in the rationales for decisions by U.S. utility regulators, taxpayer impacts will not be analyzed in this study.

2 An exception to this generalization exists in cases where it is determined that the cost excess is the result of utility imprudence. In such cases it is generally held that stockholders must absorb the full loss.

example, the frequent practice of fully allocating the sunk costs of prematurely obsolete telecommunications equipment to ratepayers who benefit from the associated technological advancement can be distinguishable in principle from applications of the sharing concept for excess utility plant and certain take-or-pay gas costs resulting from suboptimal management efficiency. However, the existence of many plainly inconsistent and even diametrically opposed treatments of uneconomic sunk costs is indicative of both the relative novelty of the problem, and the need for improved regulatory policies.

## 3. REGULATORY TREATMENT OF EXCESS CAPACITY IN RECENT ELECTRIC AND GAS UTILITY RATE CASES

### A. Federal Energy Regulatory Commission

#### 1. Take-or-Pay Liabilities

In recent years the FERC has had to deal with the question of who must pay for billions of dollars of excessive gas supply costs incurred by interstate pipelines. The excess costs resulted from gas supply contracts entered into in the late 1970's and early 1980's, when gas shortages and curtailments were a relatively recent memory, and pipelines were scrambling to position themselves for their perceived future market opportunities and requirements. Gas supply contracts of that period customarily involved "take-or-pay" clauses requiring the pipelines to take or pay for, (sometimes at relatively high prices), a substantial percentage of all gas committed for delivery by natural gas producers. For a variety of reasons, including higher gas costs and consequent alternative fuel competition, end-user conservation, competition from other pipelines, and growth of transportation at the expense of sales, the pipelines' projected sales demand failed to materialize. These trends accelerated as a result of the FERC's Order 436, which effectively limited the pipelines' power to restrict transportation in order to protect their own sales. In addition, the quantity of gas offered for delivery by producers in many instances exceeded the pipelines' expectations. The frequent result was an excess of contracted-for gas supply over what the pipelines could market (given the purchase prices they had agreed to), leading to the accumulation of large take-or-pay claims by gas producers against the pipelines. In extricating themselves from these liabilities, which in some instances threatened insolvency, pipelines have been forced to spend billions of dollars for take-or-pay "buy-out" payments to gas producers, and other gas supply contract reformation costs.

The regulatory solution to the take-or-pay crisis proposed by a number of pipelines was "direct-billing", an exit-fee scheme under which most or all of the incurred take-or-pay costs would be directly billed to customers who had reduced or eliminated their purchases, and who were therefore "responsible" for the excess gas supply commitment and its cost. The advantage of direct-billing, from the pipelines' perspective, was that it would permit full cost recovery from customers without further depressing sales. Customers objected to directly-billed charges on grounds that a purchase-deficiency based charge would not fairly reflect the actual cost of service to customers, and would simply amount to a "bail-out" of pipelines from the consequences of their own market forecasting mistakes. Customers contended that prudently incurred take-or-pay costs should be recoverable, if at all, only through commodity rates, with stockholders at risk if increased commodity charges led to further sales erosion.

The FERC attempted to resolve these issues in Order No. 500, Interim Rule and Statement of Policy, Docket No. RM87-34-000. In that Order, the FERC adopted a policy of "sharing" the sunk costs of excess gas supply between shareholders and ratepayers:

> In brief, no one segment of the natural gas industry or particular circumstance appears wholly responsible for the pipelines' excess inventories of gas. As a result, all segments should shoulder some of the burden of resolving the problem.

The FERC implemented this burden-sharing approach by giving pipelines the option of commodity rate treatment for all prudently incurred take-or-pay costs, but allowing direct-billing of between 25 and 50 percent of such costs for pipelines that were willing to write off an amount of take-or-pay costs equal to the amount directly billed. The direct-billing option was limited to pipelines that agreed to offer non-discriminatory transportation service. The directly-billed charges would be based on customers' respective "contributions" to the take-or-pay problem as measured by "purchase deficiencies."

In effect, the FERC's policy in Order 500 amounts to a partial "market test" for determining the stockholder-rate-payer responsibility for take-or-pay costs. Full cost recovery will be realized only for pipelines whose sales volumes can withstand the competitive pressure of an increase in commodity rates sufficient to recover take-or-pay costs. Such pipelines, in effect, will be rewarded for their success in keeping costs and rates low enough to withstand competitive market resistance to a price increase without a corresponding loss of sales. Pipelines with a less favorable competitive position will be permitted to bypass market constraints with a direct-billing mechanism, but only if stockholders absorb costs equal to the amount directly-billed.

### 2. Pipeline Throughput

In conjunction with its policy in recent years of fostering increased competition in the pipeline industry, the FERC has begun to focus increased attention on the issue of who pays for the costs of underutilized pipeline capacity. The issue typically arises in designing a pipeline's volumetric (i.e., commodity and transportation) rates, a process which involves dividing the pipeline's commodity and transportation related revenue requirements by appropriate levels of sales and transportation volumes (throughput). In various cases dating back to the mid-1970's, the FERC assigned some portion of the risk of under-utilization of the pipeline's capacity to stockholders. This was accomplished by calculating the pipeline's volumetric rates using a pro forma throughput level which may be greater than the current actual or projected throughput. The pro forma throughput level was intended to represent reasonably full utilization of the pipeline's capacity. If the pipeline is subsequently unable to achieve throughput equal to its pro forma full-utilization level, any fixed costs assigned to the unrealized sales volumes would not be recovered through rates, and would thus be absorbed by stockholders in the form of lower earnings.

The FERC and its staff have typically defined "full utilization" of pipeline capacity either in terms of design capacity or by a maximum historical utilization measure. Since the mid-1970's, in cases involving the original certification of newly constructed facilities, the FERC has tended to base pro forma throughput on the maximum design capacity volume of the pipeline. The stated policy is to encourage efficient management and discourage unnecessary capacity expansion by assigning some risk of underutilization to stockholders. In several cases involving long-established pipelines, where the design maximum throughput concept was not used upon initial certification, the FERC staff has favored a "full utilization" throughput level based on a historical utilization measure. Currently, the FERC staff's policy is to impute throughput equal to the maximum annual level of the previous five years.

An often-cited case in which the FERC determined pro forma throughput on the basis of design capacity is High Island Offshore System, 55 FPC 2674, reh. granted in part, 56 FPC 725 (1976). The Commission's HIOS order specified that rates should be premised on achieving throughput equal to "the initial design capability of the project" in order to place "upon the applicants the risk of their failure to do so." Eight years later, in a subsequent rate case, HIOS argued that the policy of basing pro forma throughput on the design maximum should be applied only for a limited period after the commencement of its operations. The FERC, in rejecting that argument, stated that "the concern that HIOS share in the economic risks of system underutilization was certainly one that will be relevant over the life of the project" and that HIOS should be encouraged "to fully utilize its system over the long term." High Island Offshore System, 31 FERC 61,010, reh. denied, 32 FERC 61,286 (1985).

In determining the extent to which stockholders should be exposed to the risk of unrecovered capacity costs, the FERC has at times considered the circumstances under which the pipeline's management made the decision to construct the pipeline facilities. In Mustang Fuel Corporation, 31 FERC 61,265, the FERC stated that transportation rates for intrastate pipeline facilities constructed after enactment of the Natural Gas Policy Act (NGPA) to provide service under Section 311[3] should allocate the risk of under-utilization to the pipeline's shareholders. Since the NGPA allows firms to construct Section 311 facilities without first obtaining a certificate of public convenience and necessity, the FERC in Mustang concluded that firms would face an uneconomic incentive to construct unneeded facilities if stockholders did not bear the risk of underutilization. However, the Commission distinguished Mustang's newly constructed, post-NGPA facilities from its "existing" intrastate facilities, which were not FERC-regulated when they were constructed. In concluding that Mustang's stockholders and interstate ratepayers should "share" the risk of underutilization for such

3 The NGPA exempts interstate pipelines from prudence scrutiny of transportation charges paid to intrastate pipelines.

existing facilities, the Commission noted that "Mustang's evaluation of the economic viability of the [existing] facilities and its decision to construct could not have been distorted by any assumption that costs resulting from overbuilding could be passed through to interstate customers."

More recently, in Lear, the FERC reaffirmed and elaborated on the Mustang policy. In Lear, the Commission reversed an Administrative Law Judge's decision that Lear's gas transportation rates should be based on projected actual volumes, rather than the pipeline's design capacity. The Commission adopted the staff's position that the entire risk of unutilized post-NGPA constructed gas transportation capacity should fall on stockholders. The Commission stated,

> We believe that this [the Commission's policy] can be accomplished only through basing the rates upon a percentage of capacity representing full utilization of the system, rather than on some lesser level of projected throughput based upon actual experience. This will protect the interstate customers from underutilization, since, even if the system is underutilized, they will pay the same rates they would have paid had the system been fully utilized. To the extent that the Anadarko System achieves full utilization, Lear will earn its full rate of return. If the system is underutilized, however, it will not recover the full rate of return. This places the risk of underutilization where it should be -- on Lear which independently determined the size, location, and type of facilities it constructed. Mak-

ing Lear accountable for those decisions promotes sound construction decisions.[4]

The "percentage of capacity representing full utilization" of Lear's system was found to be 90 percent of its design capacity, allowing 10 percent "downtime" for maintenance. Since Lear's rate was a one-part commodity rate (i.e., no demand charges), the result was to make the recovery of all of Lear's fixed costs proportionate to its achieved throughput, with a 90 percent capacity factor required to recover all of its fixed costs.

Although the FERC staff's policy of allocating risk of underutilization to stockholders for long-established pipelines is somewhat less aggressive than the Commission's policy for newly constructed facilities, some of the FERC's policy statements since the early 1980's have emphasized allocating some such risk to stockholders. In analyzing the appropriate regulatory policy for pipelines faced with "competitive alternative fuel prices", the Commission concluded that it may be necessary "to protect the ratepayers from the cost burden of underutilization of pipeline facilities which may result from load loss."[5]

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4 Federal Energy Regulatory Commission, Lear Petroleum Corp., Opinion and Order, Docket No. ST83-429-001, et al. (January 15, 1988), p.28.

5 Federal Energy Regulatory Commission, Tennessee Gas Pipeline Co., Opinion and Order, 21 FERC 61,004 (1982).

In Order 436, which promulgated rules intended to foster competition in the pipeline industry, the FERC underscored its intent to assign to stockholders a significant share of idle capacity costs resulting from the failure to maintain reasonable throughput:

> [T]he Commission fully intends to scrutinize projected levels of service and rates of return filed in rate cases as a means of maintaining pipeline throughput.[6]
>
> Common sense and economic theory both suggest that putting a firm at risk for the consequences of its investments and operational decisions can affect the incentives to undertake those decisions judiciously: a firm is more likely to work to minimize its costs if its financial health is at stake...[7]

The somewhat indefinite language of these orders was given concrete interpretation by the FERC staff in Colorado Interstate Gas Company (1986).[8] In that case, the staff imputed throughput based on historical levels rather than lower currently projected levels. The staff contended that the underutilized status of CIG's system rendered it less than fully used and useful. In the Administrative Law Judge's initial decision, the ALJ accepted CIG's position that the staff's imputed throughput would deny CIG a fair

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6 Federal Energy Regulatory Commission, Order No. 436, at 31,525

7 Id., at 31,534.

8 Federal Energy Regulatory Commission, Colorado Interstate Gas Company, Initial Decision, Docket No. RP85-122-000 (May 13, 1986).

opportunity to earn the authorized rate of return, and that this would be unreasonable in the absence of a finding of imprudence.

More recently, however, the FERC staff's interpretation of the Commission's throughput policy expressed in Tennessee and Order 436 was accepted by an Administrative Law Judge Decision in ANR Pipeline Company.[9] In that case, the ALJ adopted a staff witness's proposal to base the pipeline's pro forma throughput on the maximum annual throughput actually achieved by the pipeline in the preceeding five years. The staff's pro forma throughput was 1,176 BCF, or about 85 percent more than ANR's projected throughput of 635 BCF.

The ALJ stated that the appropriate throughput level should be considered in connection with ANR's implementation of the modified fixed-variable (MFV) cost allocation methodology. Under MFV, fixed costs are recovered through demand charges, except for return on equity, income taxes, and certain fixed production and gathering costs, which are recovered through commodity rates. The ALJ's rationale was that,

9 Federal Energy Regulatory Commission, ANR Pipeline Company, Initial Decision, Docket No. RP86-105-000 et al. (November 12, 1987).

> Under the MFV method, ANR is guaranteed recovery of most of its fixed costs through its demand charges... Therefore, ANR should be required to achieve a realistic level of total system throughput. If it does not effectively and efficiently strive to achieve reasonable design volumes, it will not earn profits for its shareholders.[10]

The ALJ also based the imputed throughput decision on the traditional regulatory standard that only the cost of plant that is "used and useful" should be recovered in rates:

> The encouragement of maximum utilization is consistent with the general principle that a regulated company should only earn a return on a rate base that is used and useful... To the extent that ANR does not maintain this [imputed] throughput, its facilities are less used and useful to its customers. This reduced usefulness should be reflected in ANR's rates.[11]

The effect of the ALJ's policy was to make ANR's achieved equity rate of return proportionate to ANR's ability to achieve the pro forma throughput level representing reasonably full utilization of its system. If ANR's projections of its actual throughput were accurate, to set rates based on the ALJ's 85 percent higher imputed throughput level would effectively impose a cost disallowance on ANR. The ALJ's policy in ANR thus amounts to a substan-

10 Id., p. 50.
11 Id., pp. 52-53.

tial, but far less than total, allocation of underutilization costs to stockholders. Since essentially all of ANR's fixed costs other than equity return and income taxes were recoverable through demand charges, which ANR would collect regardless of throughput, the ALJ's decision effectively limited the risk of ANR's stockholders to the inability to achieve some portion of its authorized equity return. The ALJ's policy stopped short of requiring stockholders to face the risk that low throughput might cause substantial net losses (i.e., a negative equity return) that could result from an inability to collect fixed costs other than return on investment. At this time (July 1988), the Commission itself has not yet issued a final order accepting or rejecting the staff's policy of imputing throughput based on historical maximum levels.

### 3. Abandoned Plants

A major issue in regulating electric power utilities, especially in recent years, has been the proper treatment of the sunk costs of abandoned construction projects. In many cases, the failure of the utility's projected load growth to materialize due to forecasting errors, competitive pressures, economic downturns, or conservation, led to the decision to cancel. In other instances, the utility was simply unable to complete the project due to excessive cost or mismanagement. Sometimes both circumstances were involved.

In an order issued in early 1988, the FERC analyzed the appropriate stockholder-ratepayer responsibility for the prudently incurred costs of abandoned electric power plant construction projects.[12] The Commission concluded that prudently incurred canceled plant costs should be equally shared by ratepayers and stockholders. In that case, NEPCO and other utility intervenors had argued that the Commission should reverse its then-existing policy of allowing amortization of the cost of abandoned plants over a period of years, but disallowing any return on the unamortized cost during the amortization period. NEPCO proposed that utilities should receive rate base treatment of abandoned plant losses, as well as amortization, which would effectively shift the entire cost of the canceled plants to ratepayers.

In rejecting NEPCO's proposal, the Commission stated that its policy should continue to require a "sharing" of prudently incurred canceled plant costs between stockholders and ratepayers. However, the Commission modified its previous policy in order to ensure that the allocation of the cost between the parties should be exactly equal. This was

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12 Federal Energy Regulatory Commission, New England Power Company, Opinion and Order, Docket Nos. ER85-646-001, et al. (January 1988).

effected by requiring electric utilities to write off half the cost of such projects upon abandonment, with the remaining half both amortized <u>and</u> (until amortized) included in rate base. Under the previous policy, stockholder-ratepayer sharing may not have been exactly equal, because the cost to stockholders of financing a canceled plant during an extended amortization period would not necessarily equal the cost to ratepayers of the amortization of the plant.

In reaching this decision, the Commission rejected a number of rationales for shifting the risk of abandonment losses more heavily towards either ratepayers or stockholders. The Commission rejected utility arguments that investors have a legal or equitable entitlement to recover all canceled plant costs not shown to have been imprudently incurred. In particular, the Commission dismissed the rationale that, since investors cannot earn "supernormal" profits on completed plants, investors are equitably entitled to protection from prudently incurred losses on plants that are abandoned. Such investor protection, according to the Commission, would violate the "important tenet" of the "regulatory compact" that "the interests of the shareholders and ratepayers are to be balanced equitably."

Nor was the Commission persuaded by the utility argument that disallowance of canceled plant costs would unduly bias utility construction decisions in favor of low-risk, short lead-time projects.

> The decisions to substitute short-lead time plants may or may not appear to be an economically rational approach to the uncertainty of future load growth and the high cost of capital reflecting the particular circumstances facing each utility. We are not prepared to say at this time that this is inappropriate.[13]

Consumer intervenors proposed that the stockholder-ratepayer sharing of canceled plant costs should be rejected in favor of a strict "used-and-useful" standard that would require complete disallowance of canceled plant costs. In rejecting that proposal, the Commission reiterated its policy of "balancing" the interests of stockholders and ratepayers, and stated that "the 'used and useful' standard is only one of several permissible tools of ratemaking."

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13 Id., pp. 21-22.

## B. State Commissions

### 1. Industrial Rate Discounts

Relatively low levels of capacity utilization on many gas pipeline, gas distribution company, and electric utility systems have raised costs and, thus, further suppressed market demands in many states in recent years. The attempt to spread excess utility capacity costs over relatively low sales volumes has promoted conservation and made competitive alternatives more attractive, while increasing the inclination of utilities and regulators to attempt to utilize more capacity by allowing special contracts, rate discounts or other inducements, especially for price-elastic industrial customers, to maintain or increase loads. It is in the context of rate proceedings on these issues that state regulators have most frequently addressed excess capacity costs resulting from competition, and the appropriate ratepayer-shareholder allocation of such costs. Rate orders issued by four state commissions (California, Ohio, Illinois, and Indiana), illustrate the diverse policies (full allocation to ratepayers, "sharing", and full allocation to stockholders) that state commissions have adopted.

## California

The California Public Utilities Commission has recently conducted a major generic proceeding on guidelines for cogeneration deferral rate discounts and industrial load retention rate discounts and the ratemaking treatment of the resulting revenue impacts.[14] The CPUC determined that such discounts were in the public interest, given the benefits to be obtained from avoiding artificial competitive advantages flowing from its rate design policies, and the benefits of more fully utilizing the current excess electrical generating capacity surplus in California. However, the CPUC specified that the "floor" for such discounted rates should be the short-run marginal cost of the utility, and that the duration of the discount should not extend beyond the expected period of capacity surplus:

> The term of a special contract conforming to the guidelines should not extend into any year when forecasts indicate that additional capacity will be needed to meet target reserve margins. The purpose of allowing special contracts is to take advantage of existing excess capacity. Considerable justification will be required to demonstrate the benefits of extending discounted rates into a period when increased demand creates a need for additional capacity.

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14 California Public Utilities Commission, Re: Electric Utility Ratemaking Mechanisms, Decision 88-03-008 (March 9, 1988).

The CPUC also addressed the question of stockholder-ratepayer allocation of revenue losses. Under the CPUC's earlier policy, revenue losses resulting from negotiated rate discounts would be automatically recovered from other ratepayers through "tracker" mechanisms designed to adjust rates periodically to offset rate of return attrition and to reflect sales volume fluctuations. Citing excess capacity and increased competition in electric power markets, as well as other changed circumstances, the Commission determined that the trackers for the large industrial class should be abolished:

> Recent circumstances persuaded us to modify this system of regulation. One such circumstance is the existence of a short-term capacity surplus in California. This surplus resulted largely from the addition to rate base of several large, capital-intensive baseload plants...
>
> The increase in rates resulting from these large rate base additions makes it attractive for more and more customers to consider building and operating their own generation units, especially when these units can be integrated with industrial processes through cogeneration... With these economic and technological developments, we have seen considerable self-generation and bypass of the utility's system in recent years.

The effect of the CPUC's new policy was to shift the risk of discounted rate revenue loss to stockholders, at least until the utility's next general rate adjustment.

However, the CPUC did not indicate any intention to assign any prudently incurred revenue losses to stockholders in the context of general rate cases. Thus, the effective result of the CPUC's new policy is to limit stockholder exposure to competitively-induced rate discounts to the interim between general rate adjustments. Although the CPUC's policy change represented some shift of competition-related risks to stockholders compared to previous CPUC policy, the effect of that shift is merely to place California electric utilities on the same footing as utilities under traditional regulation, wherein stockholders accept the risks and rewards of sales fluctuations between general rate cases.

## Ohio

Relatively high electric rates in some areas, coupled with an increasingly cost-conscious industrial sector, have highlighted competitive impacts to an unusual degree in Ohio. In Cleveland Electric Illuminating Company, 85-675-EL-AIR (June 24, 1986), the Public Utilities Commission of Ohio (PUCO) ruled that the revenue shortfall resulting from a previously approved $2.6 million rate discount to a large industrial customer, Elkem Metals Company, should not be charged against CEI's earnings. Elkem had claimed that a reduction in electric rates was necessary for it to remain competitive in its markets, and that failure to grant relief would jeopardize the continued operation of its plant. In rejecting a staff proposal that the revenue loss should be shared equally between other customers and CEI's stockholders, the Commission cited the benefits to ratepayers and the local economy of CEI's efforts to retain existing load and gain new load. The Commission also noted that CEI's stockholders had absorbed the entire revenue loss from Elkem up to that point. However, the Commission cautioned that its decision does not "stand for the proposition that ratemaking adjustments of the type proposed by staff will always be regarded as inappropriate. In fact, the staff proposal represents an opportunity to develop a Commission policy to deal with the allocation of risk in this difficult area."

The PUCO revisited the issue of who pays for load retention measures in Toledo Edison Company (1987).[15] The Commission had previously authorized "incentive rates" that reduced power costs for certain large industrial customers of Toledo Edison in recognition of competitive conditions in the customers' industries. In a concurring opinion, Commissioner Gloria L. Gaylord noted that "Toledo Edison has the highest rates in the state at the present time. The Company cannot afford to increase its rates much higher because it risks losing more of its industrial customers to

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15 Public Utilities Commission of Ohio, Toledo Edison Company, Docket No. 86-2026-EL-AIR (December 16, 1987).

alternative fuel sources." The Commission concluded that "the rate incentives were important ingredients in the customers' decisions to retain or add production to facilities in the Toledo Edison service area." Citing the benefits to shareholders of maintaining or increasing industrial sales levels, the Commission ruled that stockholders should absorb 40 percent of the lost revenues.

## Illinois

The Illinois Commerce Commission has recently (December 1987) issued a study of incentive rates (discounted industrial rates) offered by gas and electric utilities in Illinois. Entitled Economic Development, Incentive Utility Rates--Policy Analysis Report, the study concluded that incentive rates had benefited the public, utilities, and ratepayers, but recommended that such discounts only be approved subject to certain constraints. These include an expiration of the discount no later than the period of expected excess capacity. More important, the study concluded that stockholders should absorb the entire difference between revenues under the discounted rates and revenues that would have resulted if full tariffed rates had been charged.

The Illinois Commerce Commission's policy of requiring stockholders to absorb revenue losses resulting from discounted rates was illustrated in a recent cogeneration deferral proceeding. In approving a cogeneration deferral discount rate between Commonwealth Edison Company and Abbott Laboratories, the Illinois Commission ruled that the foregone revenues resulting from the discount would be imputed in Edison's next rate proceeding -- thereby causing stockholders to absorb the entire rate discount.[16] Referring to the Commission's treatment of prior load retention and cogeneration deferral rates in three other orders, the Commission stated that,

> In these previous filings the Commission stated its intent that, at the time of a rate case, revenue adjustments will be made to ensure that shareholders bear the burden of any revenue requirement loss between full rates and discounted rates.

Implicitly recognizing the large amount of surplus capacity on Edison's system, the Commission concluded that the rate offered to Abbott was "more economic than cogeneration" because it exceeded Edison's short-run marginal cost. Therefore, the Commission concluded that the rate discount should be approved subject to the Commission's policy that rate case "revenue adjustments will be made to

16 Illinois Commerce Commission, Commonwealth Edison Company, Order No. R-18702, February 24, 1988.

reflect the full amount of revenue that would have been received if the sales under the contracts had been made at otherwise applicable rates."

<u>Indiana</u>

The Indiana Utility Regulatory Commission ruled that Northern Indiana Public Service Company could offer cogeneration deferral discount rates to industrial customers, but that NIPSCO's shareholders should bear the risk of revenue loss from the discount.[17] The Commission stated that "There is agreement of the parties that Petitioner has capacity in excess of reasonable reserve requirements and therefore deferral of some on site generation is in the best interest of other ratepayers and the utility." The Commission noted that the immediate revenue loss from the discount would be borne by stockholders, and concluded that "in the absence of clear and convincing evidence to the contrary, Petitioner's shareholders should continue to bear the total risk of loss" when rates are set in future rate cases. Thus, the Indiana Commission's decision created a <u>presumption</u> of full stockholder responsibility for rate discounts, but left open the possibility of alternative allocations if warranted by "convincing evidence".[18]

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17 Indiana Utility Regulatory Commission, <u>Re: Northern Indiana Public Service Company</u>, 89 PUR4th 385.

18 <u>Id</u>., p. 399.

## 2. Excess Electric Production Capacity

A number of jurisdictions have excluded electric generating plants from rate base (or otherwise disallowed costs) on the ground that such plants represent excess capacity. Such disallowances generally are premised on a comparison of the utility's total generating resources with test-year loads. If resources exceed loads by more than a reasonable reserve margin, the cost of the excess capacity is disallowed. The causes of the excess capacity usually involve overstated forecasts of load growth due to forecasting errors, depressed economic conditions in the utility's service territory, or competitive pressures. Although commission orders seldom attempt to quantify each contributing factor, all of these factors are probably involved to some extent in most excess capacity cases. Excess capacity decisions in Connecticut and Arkansas have shown more than usual emphasis on the impacts of competition.

### Connecticut

In February 1988, the Connecticut Department of Public Utility Control determined that the costs associated with 254 megawatts of excess capacity should be disallowed (subject to certain offsystem sales credits) in a Connecticut

Light and Power Company case.[19] The decision was the Department's first application of Connecticut's excess capacity statute, which requires the Department to exclude from the company's rates the cost of any generating facilities in excess of the level that would provide a net economic benefit to the customers of the company.[20]

CL&P expressed serious concern over how its rate design was impacting its competitive situation, projecting that as much as 15 to 20 percent of its projected load was at risk of being lost to competitors. The Company also cited projected rate increases due to payments to small power producers and the phase-in of Millstone 3 rates as sources of its competitive concerns. However, the Department was not persuaded that CL&P's competitive situation warranted any rate design change to shift more costs to captive customers. Although the Department stopped short of explicitly declaring an intention to assign the risk of future load loss to stockholders, the Department warned that,

> ...the Company's most appropriate response to competitive threats should emphasize quality and reliability of service delivered to the customers, and further improvement of cost containment and productivity of operations. The neglect of these basic elements of service will accelerate the erosion of customer confidence and the search for

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19 Connecticut Department of Public Utility Control, Connecticut Light and Power Company, 90 PUR4th 148.

20 Connecticut General Statutes, Section 16-19aa.

alternatives to purchases from the utility. Adjustments in rates or changes in rate design cannot be expected to fully compensate for the deterioration of service.[21]

## Arkansas

Arkansas Power & Light Company acquired a massive excess capacity problem as a result of an FERC allocation of capacity from Middle South Utilities' Grand Gulf I unit to AP&L. The allocation caused AP&L's 1985 reserve margin to rise to approximately 58 percent. In a settlement reached with the Arkansas Public Service Commission, AP&L agreed to absorb a major portion of the resulting excess capacity costs. However, the portion of Grand Gulf I costs that was recovered in rates was apparently sufficient to cause (or contribute to) the departure of AP&L's largest customer, Reynolds Metals Company's aluminum smelter, which had accounted for as much as 15 percent of AP&L's load.

The departure of Reynolds (whose production in lower cost plants in Canada and the Northwest was simultaneously increasing) obviously exacerbated an already severe excess capacity problem. What makes this case particularly interesting is that it is one of the few instances in which a departed customer was required to continue to make substantial payments toward the fixed costs of its former utility

21 90 PUR4th 148, 176.

supplier. Three years earlier, the Arkansas PSC had approved a special contract between AP&L and Reynolds. The contract had provided a "load retention" type discounted rate for Reynolds, whose Arkansas aluminum smelting operations were economically marginal at that time. However, as part of the contract, Reynolds agreed to continue to make contract demand charge payments to AP&L even if Reynolds departed AP&L's system. In reluctantly approving the contract rate, the PSC stated,

> At bottom, there is only one reason why we do approve it, and that is because there is some possibility that the other customers would have to bear some $15 million in annual capacity costs if Reynolds does not. Without the contract, there would be no chance that Reynolds would pay these capacity costs in the event it closed its doors and departed.[22]

However, the PSC warned that AP&L was not guaranteed any right to recover costs not paid by Reynolds in the event it did depart:

> To say it [the contract] is a well written document is to speak from Reynold's viewpoint, since it appears to be heavily weighted in favor of Reynolds. This is possibly best explained by AP&L's belief that whatever costs are not borne by Reynolds will be passed on to the other ratepayers. We state here that such a view is not axiomatic.[23]

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22 Arkansas Public Service Commission, Arkansas Power & Light Company, Order No. 23, Docket No. 82-314 (1985), at pages 6-7.

23 Id., p. 6.

The take-or-pay provision of the contract ultimately resulted in Reynolds paying approximately $41 million for demand charges after it had shut down its Arkansas smelting operations.

### 3. Rate Design and Cost Allocation

Rate design and cost allocation have been another major focus of regulators' attempts to mitigate adverse competitive impacts on electric and gas utilities. The emphasis has been on reducing or eliminating perceived subsidies flowing from high load factor customers -- particularly industrial and large volume commercial customers -- to low load factor residential and small commercial customers. Eliminating such "subsidies" effectively requires shifting significant fixed cost responsibility from industrial customers to the small commercial and residential classes.

#### California

Policies adopted by the California Public Utility Commission (CPUC) are a major example of overhauling cost allocation and rate design policies in order to combat uneconomic bypass of utility systems. For some years, the CPUC has used a marginal cost rate design method. The marginal cost method used by the CPUC has resulted in the allocation of a substantial part of fixed production costs to energy rather than demand, which produces higher rates per kilowatt hour for high load factor classes, such as the industrial class, than would be the case if more fixed production costs were allocated in proportion to demand. Although the CPUC's marginal cost allocation methods do not inherently subsidize any class, actual application has sometimes permitted non-industrial classes to pay a smaller portion of their marginal costs than the industrial class. That is so because the CPUC does not fully adjust rates so that each class pays rates proportion to its marginal cost. For example, if "pure" marginal cost rates would produce total revenues in excess of a utility company's total revenue requirement, the CPUC, rather than adjusting all rates down proportionally, in some instances adjusted only selected rate components (e.g., customer charges which affect residential customers more than industrial customers) to achieve revenue adequacy. The industrial class has thus been required to pay a higher percentage of its marginal cost than other major classes.

The CPUC has, in recent years, become increasingly concerned about the possibility of high industrial rates causing industrial customers to reduce or eliminate utility service by generating their own electricity or relocating outside California. The CPUC addressed these concerns in its Interim Opinion, Decision 87-050-071, May 29, 1987, in which it announced new policies designed to reduce subsidization of other classes by the industrial class and to prevent loss of industrial customers.

One of these new policies is the allowance of special contracts for Large Light and Power Customers. Utilities will be allowed to negotiate special rates with industrial customers who "present a credible threat of imminently developing self-generation capability." Although the negotiated electricity price under such contracts may be significantly less than existing tariff rates, the CPUC required that such rates recover at least the short-run marginal costs of providing power. In instances where capacity additions are expected within the contract period, the minimum price must recover the long-run marginal cost of power. The allowance of such special contracts for large industrial customers is an especially important development because such contracts may create a reversal of the previous pattern of subsidies in California. The special contracts may result in industrial customers paying a lower percentage of their marginal costs than other customers in general.

The CPUC also mandated continued movement toward full allocation of revenue based on equal percent of marginal cost, thereby gradually reducing the subsidies flowing from one class to another, and it further mandated removal of the Attrition Rate Adjustment (ARA) for the Large Light and Power class. The ARA was a rate surcharge designed to compensate for rising utility costs.

The CPUC's emphasis on avoiding bypass by industrial customers by shifting more cost responsibility to residential customers is also apparent in a recent Southern California Edison general rate case (Application No. 86-12-047). In that case, the CPUC staff and Edison jointly presented a study of cost allocation and rate design which recommended that existing interclass subsidies, which had benefited residential customers at the expense of industrial customers, should be phased out over three years.

## Virginia

In September of 1986, the Virginia Corporation Commission issued a generic order on the subject of economically efficient rate design for gas utilities.[24] The stated intent of the order was to reassess natural gas industrial rates in response to the FERC's Order No. 436 and other factors that have increased competition in the natural gas industry. Among the Commission's specific objectives was to

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24 Virginia State Corporation Commission, Ex Parte, In the Matter of Adopting Commission Policy Regarding Natural Gas Industrial Rates and Transportation Policies, Case No. PUE 860024 (September 9, 1986).

permit gas utilities to compete effectively with alternate fuels and to prevent bypass.

The Commission determined that these objectives would best be met by allowing gas distribution companies to offer flexible interruptible sales, with a price floor equal to the highest cost source of gas. Regarding bypass, the Commission stated that "appropriately designed embedded cost of service rates should eliminate the economic incentives for bypass." The Commission also stated its intention to authorize cost of service based transportation rates, and to gradually eliminate existing subsidies to residential customers in firm sales rates. No indication was given that any revenues would be imputed to discounted sales transactions so as to allocate any part of foregone revenues to stockholders.

## Wisconsin

In June of 1987, the Wisconsin Public Service Commission issued a generic order setting forth new policies concerning transportation services and rate design for natural gas local distribution companies.[25] Although the Commission stated that it would not adopt a policy of discouraging transportation in order to maintain LDC sales, the Commission did specify measures designed to protect the LDC's

25 Wisconsin Public Service Commission, Enunciation of Principles, Docket No. 05-GI-102 (July 9, 1987).

"captive" customers from any adverse impacts resulting from a transportation customer returning to system supply if spot gas prices should rise above the LDC's system supply cost. One such measure was "that the transporting customer be permitted to pay the LDC a 'standby charge' in order to have the right to an early return to system supply."[26]

The Commission also set forth policies concerning flexible gas transportation rates. Although the Commission decided to permit such discounted rates in order to "retain the LDC customers who would otherwise be lost", the Commission ruled that such discounts would not be made up by other ratepayers:

> It is, of course, possible for an LDC to discount prices, lose earnings because of that discount and eye the next rate case as an opportunity to make its shareholders whole via help from ratepayers. The commission desires to be clear that it strongly discourages a utility's attempt to make up in the next rate case for losses due to these downward rate variations.[27]

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26 Id., p. 25.
27 Id., p. 31.

## 4. EXCESS SUNK COSTS IN THE TELECOMMUNICATIONS INDUSTRY

Excess sunk costs have been incurred in the telecommunications industry since the early 1970s as business terminal equipment (primarily electromechanical PBXs and mechanical key systems) became obsolete before it was fully depreciated. In a limited number of cases state commissions required telephone utilities to either absorb a portion of these excess sunk costs as a stockholder burden or charge them as a cost increment to the new high-tech replacement service. In most cases, however, telephone utilities were simply permitted to set basic exchange rates to cover all residual costs so that these excess sunk costs were automatically transferred to and recovered from monopoly service sectors.

This practice was sharply curtailed after AT&T's divestiture of the regional local service operating companies. Because the divestiture stripped AT&T of the basic exchange service market, further residual pricing to recover AT&T's terminal equipment costs was precluded, and the Company was thus forced to take a half-billion dollar write off against common equity capital to resolve this matter in 1985. Interestingly, local exchange service rates, which had earlier been set on a residual cost basis in most states to recover these costs, were not correspondingly reduced after the divestiture. And, in most states there have not been full-blown telephone utility service cost studies and corresponding rate cases reflecting post-divestiture cost of service conditions. This, in part, helps to explain the remarkable increase in profitability that the Regional Bell Operating Companies have experienced since divestiture occurred. At the present time, there is increasing concern in some state jurisdictions that this historical experience is now beginning to repeat itself as the regional Bell companies promote competitive Centrex service at low rates and continue to price captive basic exchange service on a residual basis.

## The Federal Communications Commission

The threat of large volume customers "bypassing" the telephone utility system has been cited by utilities and regulators in recent years as an additional possible source of excess sunk costs. Were bypass to occur on a sufficiently large scale and not be offset by additions of other customers and traffic, the result could be excess capacity and the need to dispose of the resulting sunk cost.

Although the magnitude of telecommunications bypass to date has not resulted in excess capacity findings by regulators, the concern over potential bypass has had a major impact on rate design and cost allocation. In particular, the Federal Communications Commission[28] has decided to shift more cost recovery to flat monthly customer charges (Customer Access Line Charges or "CALCs") in an effort to ensure the ability of telephone utilities to offer toll services at rates competitive with the cost of bypass for large volume customers.

In addition, since the early 1980's, the FCC and many state commissions have been increasing telephone utility depreciation rates on the premise that the increasing pace of change in telecommunications technology has forced obsolescence on much telephone utility plant whose cost has not yet been recovered.[29] Where enhanced competitive services are provided from central office plant that also provides basic exchange service, the increased depreciation rates are typically applied to all services, not just those where competition is causing more rapid plant replacement. The net result of these policies, coupled with increased reliance on CALCs and other flat rate charges, has been to shift increased responsibility for fixed costs, including the sunk cost of obsolescent plant, to residential and other small users with limited or no competitive alternatives. Although the regional Bell companies and other local

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28 See, e.g., FCC Docket No. 78-72, Third Report and Order (FCC 82-579), (released February 28, 1983).

29 See, e.g., FCC Docket No. 20188, Report and Order, (1980).

exchange telephone utilities have thus far focused on "reserve deficiency" amortizations and other means by which ratepayers should pay such sunk costs, some commentators have discussed the possibility that "inadequate" rate relief may force stockholders to absorb some portion of them.[30] However, a more recent (1987) FCC study indicates that the "reserve deficiency" it had identified in the early 1980's has been substantially reduced through higher depreciation rates in recent years, and that the reserve deficiency may be virtually eliminated by 1990 under currently authorized depreciation rates.[31]

For AT&T, the relative lack of post-divestiture "captive" customers has already effectively prevented passthrough of all of its obsolescent plant costs to customers. In disclosing that it had written off hundreds of millions of dollars worth of pre-divestiture assets in 1985, AT&T stated, "At the time of divestiture, the carrying value of these assets was significantly reduced from

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30 Joseph R. Fogarty, "Telephone Company Capital Recovery: Crisis and Dilemma Persist", 117 Public Utilities Fortnightly 23 (February 6, 1986). Fogarty cites a study by the National Telecommunications and Information Administration that recommends a "substantial" reserve deficiency write-off by telephone utilities.

31 Federal Communications Commission, Accounting and Audits Division Report on Telephone Industry Depreciation, Tax, and Capital/Expense Policy (April 15, 1987).

economic value in a rate-regulated environment to economic value in a competitive environment."[32] In 1986, AT&T announced "force reductions and facility consolidations" requiring an even larger $2.5 billion pretax write-off, much of which will apparently not be recovered through higher rates.[33]

## District of Columbia

The D.C. Public Service Commission (PSC) has considered whether any revenue deficiency resulting from competitively-induced sales losses for Centrex services should be recovered from other ratepayers. In 1985, the PSC concluded a proceeding in which it set rates for the Centrex services of Chesapeake & Potomac Telephone Co. (C&P)[34] "Centrex" is a service offered by a telephone utility to large volume business customers which is intended to provide features similar to PBX systems that such customers now have the competitive option of securing from independent nonutility vendors. Thus, Centrex is a particularly price-elastic, competitive service. Centrex is an unusually large portion of C&P's business, accounting for 40 percent of the company's access

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32 AT&T's 1985 Annual Report to Stockholders, p. 22.
33 AT&T's 1987 Annual Report to Stockholders, p. 30.
34 Re Chesapeake & Potomac Telephone Company, 66 PUR4th 588.

lines in the District of Columbia, in part because of the federal government's extensive use of the service.

In considering the issue of whether any revenue deficiency resulting from the loss of Centrex customers due to bypass should be absorbed by other ratepayers, the PSC frankly stated that "our present policy is that a deficiency in one service is assigned to other services, absent substantial evidence of management imprudence."[35] In declining to address the related issue of whether investment "stranded" as the result of loss of Centrex volumes should be excluded from rate base, the PSC noted that there are few regulatory commission precedents on the subject of telephone utility investment stranded due to declining demand, because the problem has not been significant since the Great Depression of the 1930's.[36]

Although in this case the PSC declined to go beyond stating its existing general policy, they left open the possibility of reconsidering the Centrex revenue deficiency issue in future cases if the potential bypass problem actually materializes:

> We also recognize that Centrex is in transition from being a monopoly service to being a competitive service. As a result of this recognition, in a

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35 Id., p. 602.
36 Id., p. 601.

proceeding where there is substantial evidence in the record that there is a net revenue loss or deficient earnings for Centrex service, we will permit the parties in that proceeding to argue, based on the evidence, what the appropriate rate-making treatment of such loss or deficient earnings should be.[37]

37 *Id.*, p. 602.

## 5. LEGAL LITERATURE

Justice Brandeis is generally credited with originating the "prudent investment" standard relied on by utilities to support full cost recovery of excess capacity. Perhaps most frequently cited is his concurring opinion in the 1923 Southwestern Bell[38] case, wherein he stated:

> The investor agrees, by embarking capital in a utility, that its charges to the public shall be reasonable. His company is the substitute for the state in the performance of the public service; thus becoming a public servant. The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business.... The reasonable rate to be prescribed by a commission may allow an efficiently managed utility much more. But a rate is constitutionally compensatory, if it allows to the utility the opportunity to earn the cost of service as thus defined.
>
> The adoption of the amount prudently invested as the rate base and the amount of the capital charge as the measure of the rate of return would give definiteness to these two factors involved in rate controversies..[39]

Note that Justice Brandeis defines rate base as "the amount prudently invested", but also defines the shareholders' entitlement as recovery of "reasonable" costs. Does this mean that any utility cost, regardless of its magnitude in relation to benefits achieved, is "reasonable"

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38 Missouri ex. rel. Southwestern Bell Teleph. Co. v. Missouri Pub. Service Comm., 262 U.S. 276 (1923).

39 Id., pp. 290-291, 306-307.

so long as it was "prudently" incurred? It is perhaps not too far fetched to trace the current controversy over disallowance of grossly uneconomic, but arguably prudently incurred, costs to that implicit ambiguity in Justice Brandeis's language.

Roger D. Colton has compiled an extensive survey and analysis of legal theories and precedents on the subject of excess capacity disallowances, including the applicability of the "prudent investment" and "used-and-useful" standards.[40] Colton places particular emphasis on the policies of the Iowa State Commerce Commission and the Iowa legislature, both of which have required excess capacity disallowances in recent years. The Iowa General Assembly supplanted a less stringent Commission standard with the minimum requirement that any common equity return associated with excess electric utility capacity be disallowed:

> It is the policy of this state that it is in the public interest that public utilities subject to rate regulation, at a minimum, be prohibited from including either directly or indirectly in their charges or rates to customers the return on common equity associated with excess electric generating capacity... Excess electric capacity is that portion of the public utility's electric generating capacity which exceeds the amount reasonably necessary to

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40 Roger D. Colton, "Excess Capacity: Who Gets the Charge From the Power Plant" 34 Hastings Law Journal 1133 (1983). Also see a rebuttal to Colton by Louis B. Schwartz and Colton's reply. 35 Hastings Law Journal 721 (1984).

provide adequate and reliable service as determined by the commission.[41]

Colton's analysis concludes that a strict "prudent investment" standard should be rejected in favor of a "shared-cost" standard, under which excess capacity costs would be allocated between stockholders and ratepayers.

Some state courts have dealt with the proper reconciliation between the "prudent investment" and "used-and-useful" standards. For example, a Pennsylvania Commonwealth Court decision found that Philadelphia Electric Company's prudent acquisition of a plant did not suffice to compel inclusion of the plant in rate base. The Court's rationale was that prudence is a necessary but not sufficient condition for rate base inclusion:

> A unit may be properly excluded from a utility's rate base if the investment in that unit is found to be a result of managerial imprudence occurring at the time the decision to invest was made. See, e.g., UGI Corp. v. Pennsylvania Pub. Utility Commission (1980) 49 Pa Cmwlth 69, 82-87, 410 A2d 923, 932. It does not follow that a unit prudently constructed must always be included in the rate base. The touchstone for determining whether or not a prudently constructed unit should be included in a utility's rate base is whether or not, during the test-year involved, the

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41 H.F. 312 sect. 36, 70th Gen. Ass., 1st Sess. (1983), as cited by Colter, Id.

unit will be used and useful in rendering service to the public.[42]

42 Philadelphia Electric Co. v. Pennsylvania Public Utility Commission, 61 Pa Cmwlth 325, 433 A2d 620, at pp. 622, 623.

## 6. FINANCIAL AND ECONOMIC LITERATURE

### A. Cost of Capital Effects of Increased Competition

The trend towards increased competition has led some utilities, commentators, and regulators to argue that utility business risks and capital costs have increased. Standard & Poor's 1983 Credit Overview - Corporate and International Rates, judged the impacts of competition to be especially pronounced for natural gas utilities:

> Natural gas utilities certainly operate in a much more competitive market environment than electric or even telephone utilities. While regulated as wielders of monopoly power, natural gas utilities in fact compete actively for energy market share with fuel oil, electricity, coal, solar, wood, etc., with the consequence that the long-term staying power of final market demand for natural gas is a matter of continuing concern.

Citing the potential of competitively-induced sales erosion for natural gas utilities, S&P further concluded that,

> The pure business risk aspect of both pipeline and distribution natural gas companies is judged to be the highest among utilities, though given the major long-term energy role seen for natural gas, not so high as for the typical industrial company. Additionally, natural gas pipelines are judged to carry somewhat higher business risks than distribution companies generally, particularly where direct industrial sales (subject to greater long-term competitive threats than

> residential or commercial demand) contribute meaningfully to the earnings stream.

More recently, in its April 28, 1986 Credit Week, S&P cited the pro-competitive impact of the FERC's Order No. 436 as increasing the

> risks to the pipelines by reducing their assurance of cost recovery and by tying their financial performance to cost efficiency and throughput achievement ... Competition for sales and transportation customers will make achievement of representative throughput levels difficult.

For telephone utilities, S&P also perceived significant competition-related risks, mitigated somewhat by overall expansion in telecommunications markets:

> The broad scale introduction of competitive communications services continues to keep the long-term business risks at historically high levels, not significantly below those of today's natural gas industry. At the same time, the demand for communications services continues to demonstrate growth... which provides some of the business risk advantage that the telephone industry has over the natural gas industry.

However, S&P did not at that time (1983) perceive significant competition impacts on electric utility capital costs:

> While it is clear that advancing technologies, such as on-site solar, and existing competitors, such as natural gas, could take away some electric market share, there are

> regional climatic and cost considerations which tend to limit the competitive threat to certain marginal applications of electricity. Indeed, competition from these and other energy sources has existed for some time without causing any material market disruption. Despite the electric utility industry's self-imposed attempts to limit demand for electricity, no meaningful reversal of the trend in long-term growth (however modest) has yet been recorded. Although technological advance could be translated into an effective form of competition some time in the future, this is not likely to occur soon.

Some confirmation of S&P's analysis of the relative risks of electric and gas utilities can be found in a comparison of the FERC's rate of return determinations for interstate gas pipelines and electric utilities. In late 1987, the FERC staff recommended a 13 percent equity rate of return for a major interstate pipeline, based on a "discounted cash flow" study of the market cost of equity capital for a group of comparable interstate pipelines.[43] The contemporaneous FERC quarterly "benchmark" equity rate of return for electric utilities, also determined using the market-based discounted cash flow methodology, was 12.27 percent. It is reasonable to infer that the FERC staff's higher estimated market cost of equity capital for pipelines

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43 Federal Energy Regulatory Commission, Initial Brief of the Commission Staff, Columbia Gas Transmission Corporation, Docket Nos. RP86-168-000 and TC86-21-000, and Columbia Gulf Transmission Company, Docket No. RP86-167-000.

may at least partially result from pipelines' greater exposure to competitive forces, coupled with the FERC's policy of assigning a significant portion of unutilized pipeline capacity costs to shareholders. This inference is reinforced by the result in another recent case, in which the FERC increased a pipeline's authorized equity rate of return by 50 basis points to reflect risks associated with increased competition.[44]

One author, Jay Copan, has analyzed the impact of increased competition in the natural gas industry on the appropriate capital structures for affected firms.[45] Copan's conclusion was that business risks had increased significantly for gas utilities, and that this increased riskiness justifies higher equity ratios for gas utilities.

## B. Discounted Rates

The results of a survey of state commissions' policies regarding discounted rates for electric and gas service were reported in the NRRI Quarterly Bulletin of April 1987.[46] Of

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44 Alabama-Tennessee Natural Gas Co., 38 FERC 61,251, reh'g denied in part and granted in part, 40 FERC 61,244 (1987).

45 Jay Copan, "The Case for Higher Common Equity Ratios for Natural Gas Companies", Public Utilities Fortnightly, Vol. 115, No. 14 (July 11, 1985), p. 24.

46 William Pollard and Vivian Witkind Davis, "New Rates Designed to Encourage Economic Development and Load Retention", NRRI Quarterly Bulletin, (April 1987).

the 38 state commissions responding to the survey, 22 had approved one or more industrial discount rates, while two states (Oklahoma and Wisconsin) had rejected them. The authors concluded their analysis of the economic impacts of these rates with the recommendation that commissions should shift the risks of rate discounts away from other customers (i.e., customers whose rates are not discounted) and toward stockholders. Noting that rate discounts are "highly correlated" with the presence of excess capacity on the utility's system, and that excess capacity is viewed unfavorably by investors, the authors observed that "Programs that offer selective discounts to increase capacity utilization, shift the risks of the program to stockholders, and [which] succeed [in these objectives] may have little impact on the cost of capital to the utility."[47]

A more theoretical economic analysis of incentive and economic development rates was presented by Costello, et al.[48] This analysis, which primarily focuses on the conditions under which discounted rates promote economic welfare, does not explicitly treat the issue of stockholder-ratepayer allocations of discounted rate revenue losses or

47 Id., at 239.

48 Kenneth W. Costello, O. Douglas Fulp, and Calvin S. Monson, "Incentive and Economic Development Rates as a Marketing Strategy For Electric Utilities", Public Utilities Fortnightly, Vol. 117, No. 10 (May 15, 1986), p. 27.

excess capacity costs. However, the authors concluded that for utilities with excess capacity, the relative revenue requirement responsibility should be tilted, on economic efficiency grounds, toward price inelastic customers (or services) and that industrial rates should be reduced.

### C. Disallowances of Excess Capacity Costs

The issue of what constitutes excess capacity and how it should be quantified was analyzed by Yokell and Larson.[49] These authors contended that excess capacity is an economic rather than a physical concept:

> [E]xcess capacity must be defined as an economic concept and measured in dollars. With this approach, excess capacity is simply capacity not needed to provide reliable service at minimum cost. It is measured by the extra costs that the utility has and will continue to incur, relative to the minimum possible, in building and operating its system. Whether a new plant represents excess capacity depends on whether the plant would have been included in the utility's optimum supply plan had today's information been available at the time it was planned.[50]

Plainly, this standard would abandon the "reasonableness at the time decisions were made" focus of the prudence standard in favor of a frank, perfect-hindsight perspective.

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49 Michael D. Yokell, Bruce A. Larson, "Excess Capacity: What It Is and What to Do About It", Public Utilities Fortnightly, Vol. 118, No. 12 (December 11, 1986), p. 13.

50 Id., p. 15.

As the authors state, "there is no relationship between excess capacity and prudence. One is a statement of what is; the other concerns the path taken."[51]

The authors conclude that any costs related to excess capacity should be shared between stockholders and rate-payers "in an equitable manner", but state that the equitable allocation must be made on a case-specific rather than a formula basis, owing to the unique circumstances of each case.[52]

As shown in a theoretical analysis by Eli Schwartz, a proper excess capacity analysis will give proper account to the "lumpiness" of capacity additions, i.e., the tendency of capacity to be added in discrete blocks rather than continuously.[53] This characteristic of capacity additions derives from the scale economies of utility capacity. For example, electrical generating capacity cannot be added in continuous increments of a few kilowatts to match the typical pattern of load growth, since the smallest efficient generating units under prevailing technology have capacities measured in megawatts (if not hundreds of megawatts). Similar conditions may apply with respect to the sizing of

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51 Id., p. 17.
52 Id., p. 18.
53 Eli Schwartz, "'Excess Capacity' in Utility Industries: An Inventory Theoretic Approach", Land Economics, Vol. 60, No. 1 (February 1984).

new gas lines or the installation of telephone central offices and local loop networks. Thus, the economically optimal capacity expansion practice of a utility may result in capacity additions taking place ahead of the load growth for which the additional capacity is needed. This will be efficient so long as the scale economy benefits of adding capacity ahead of load growth exceed the carrying costs associated with the portion of the capacity addition underutilized until load growth catches up. As shown by Schwartz, this phenomenon must be taken into account in economically valid excess capacity analyses.

According to Schwartz, it would be mistaken to deem as "excess" any capacity additions not needed for current requirements if such capacity affords scale economies in excess of the carrying costs incurred during its expected period of underutilization. Schwartz concludes that such temporarily underutilized capacity should properly be treated as "inventory" for ratemaking purposes until full utilization is realized. Such "inventoried" capacity would not be charged to current ratepayers, but would be allowed to earn a deferred return, which would be recovered in rates once full utilization is achieved.

The ratemaking implications of bypass and excess capacity in the telecommunications industry was analyzed in a

1984 NRRI study by Racster, et al., who observed that "while most analysts of the bypass issue have implicitly assumed that the costs of stranded plant would be spread among the remaining customers, there is no reason that this should necessarily happen."[54] The authors concluded that a proper analysis of who should pay for investment stranded as the result of bypass will focus on why the bypass occurred. Excessive costs or poor management argues for stockholder responsibility, while bypass caused by rate design defects or other factors may be the responsibility of both stockholders and ratepayers.

In 1984, the NRRI also compiled an extensive survey and analysis of regulatory policies toward excess capacity in the electric power industry.[55] The authors of that study analyzed the various policy options available to regulators, ranging from full allowance to full disallowance, including deferral approaches, and the circumstances that might justify each. They concluded that utilities should consider adding future plant in smaller increments than in the past as an effective strategy for avoiding future mismatches

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54 Jane L. Racster, Michael D. Wong, Jean-Michel Guldmann, The Bypass Issue: An Emerging Form of Competition in the Telephone Industry (Columbus, Ohio: the National Regulatory Research Institute, December 1984), p. 174.

55 Alvin Kaufman, Kevin Kelly, and Ross Hemphill, Commission Treatment of Overcapacity in the Electric Power Industry, (Columbus, Ohio: National Regulatory Research Institute, September 1984).

between loads and resources. Higher interest rates in recent years and slower load growth support this conclusion. The authors also emphasized improved rate design as a promising means for increasing loads during periods of idle capacity, and thereby reducing the existing capacity surplus.

### D. Prudent Investment and Used-and-Useful Standards

Another critic of the prudence standard, John Stutz, advocates a risk sharing approach that would require investors to absorb some portion of the costs of prudently undertaken but economically unsuccessful plant investments, including excess capacity.[56] Stutz observes that a risk sharing policy would more closely parallel the conditions of competitive unregulated markets:

> In the private sector investors evaluate corporate investments on the basis of profits, not prudence--profits which are in no way guaranteed by the public. This arrangement provides a natural check on management's activities. The prudence standard removes such checks. Under a prudence standard, any notion of management responsibility for the results of its activities is clearly diminished. Risk sharing restores a measure of the responsibility for the results over management decisions found in an unregulated environment.[57]

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56 John Stutz, "Risk Sharing in a Regulated Industry", Public Utilities Fortnightly, Vol. 117, No. 7 (April 3, 1986), p. 29.

57 Id., p. 33.

However, the whole concept of a meaningful regulatory determination of "risk allocation" or "risk sharing" is attacked by Alan P. Buchmann.[58] According to Buchmann,

> No matter what regulators say, if they act lawfully, they are completely unable to determine the assignment of risk between the investor and rate payer. Given reasonable regulation--implying the establishment of rates which provide an opportunity for the utility enterprise to earn a fair rate of return--the investor bears *all* the risk, and the marketplace will automatically determine the price which they charge for doing so. If that price is included in rates, it in turn is borne by the rate payer.[59]

Buchmann's argument is that the risk that regulators will disallow some portion of a utility's costs will be perceived by investors, who will then increase the market rate of return on the utility's securities by enough to compensate for the expected value of the disallowance. If regulators, in turn, follow their "lawful duty" to reflect market capital costs in the utility's rates, ratepayers will wind up paying in return allowances what they "gained" in disallowed expenses--thus rendering risk allocations moot. Buchmann does not explain why he believes that regulators have a "lawful duty" to reflect market capital costs in rates if

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58 "Allocation of Risk between Investor and Rate Payer", in Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries, Harry M. Trebing ed. (East Lansing: MSU Public Utility Papers, 1983), p. 431.

59 Id.

those costs are inflated by management decisions resulting in excess capacity.

Benjamin Zycher argues that regulatory policies contain an "asymmetry bias" where successful investments by utilities earn no more than normal returns, while unsuccessful outcomes result in below normal returns or losses.[60] According to Zycher,

> Symmetry requires that utilities earn a normal return on *unfavorable* outcomes as well as favorable ones, and that ratepayers bear the attendant pecuniary cost of the former. For if utilities can earn only normal returns on successes, but none on failures, the inevitability of some failures obviously must reduce overall returns below normal, thus preventing the industry from attracting capital and so imposing net long-run costs upon *both* shareholders and ratepayers in the form of underinvestment and inefficient investment.[61]

In order to avoid this adverse outcome, Zycher concludes that prudent utility investments in plant should be charged entirely to ratepayers, regardless of the actual economic outcome of the investment. According to Zycher, disallowances should be imposed only for "inefficient deci-

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60 Benjamin Zycher, "Economic Efficiency in Plant Construction Prudence Reviews", Public Utilities Fortnightly, Vol. 121, No. 12 (June 9, 1988), p. 22. Utility company advocates, such as Alfred E. Kahn and Lewis Perl, have made similar "asymmetry" arguments in rate cases.

61 Id., p. 23.

sions," i.e., decisions whose expected cost exceeded the expected benefits at the time the decision was made.

Taking a somewhat more legalistic and institutional perspective, utility lawyer Edward Berlin also argues for the continued viability of the prudence standard.[62] Berlin asserts that "significant questions of constitutional law" are raised by any disallowance of prudently incurred costs. Berlin also focuses on the damage he fears that disallowances will wreak on utility willingness to risk their capital on needed future construction projects. His recommendation is that "a measure of certainty" be introduced into utility planning by assuring utilities that "they will not be penalized for decisions that were the product of rational decision making."[63]

An extensive financial, economic, and legal analysis of the "prudent investment" standard can be found in a 1985 NRRI report.[64] The authors observed that the conceptual relationship between the "prudent investment" and "used-and-useful" standards could be viewed a number of ways, with the

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62 Edward Berlin, "Excess Capacity, Plant Abandonments, and Prudent Management", Public Utilities Fortnightly, Vol. 114, No. 11 (November 22, 1984), p. 26.
63 Id., p. 31.
64 Robert E. Burns, Robert D. Poling, Michael J. Whinihan, Kevin Kelly, The Prudent Investment Test in the 1980s (Columbus, Ohio: National Regulatory Research Institute, April 1985).

prudence standard far less clearly defined in law than the used-and-useful standard. One reconciliation proposed was to view the used-and-useful standard as a threshold test. If a utility investment passes that test, then the prudence standard could be imposed as an additional requirement. For example, even if a plant is arguably being used and is useful, it still remains to be shown that the utility has selected the best available option of those available in acquiring the plant; e.g., whether peaking capacity would have been more prudently acquired than a base load unit. The authors emphasized the flexibility of legally permissible applications of the prudent investment test, concluding that "The proper use of the prudent investment obligation can put the economic risk where it belongs--with the utility owners and their management agents."[65]

65 Id., p. 195.

## 7. WHO PAYS FOR SUNK COSTS: POLICY ANALYSIS

### A. "Prudence" vs. The "Used-and-Useful" Standard

In determining who pays for uneconomic sunk costs, regulators frequently must reconcile longstanding regulatory protections for customers and investors. With regard to utility capacity idled by competitively-induced sales losses (especially where such losses were not stimulated by excessive utility costs), the traditional rule that utility rate base include only "used and useful" plant may conflict with the other traditional presumption that investors are entitled to recover reasonable and prudently incurred costs. This conflict arises when sales are lost, notwithstanding prudent conduct and (at least before market circumstances changed) efficient capacity expansion by the utility's management.

The "used-and-useful" standard recognizes that mere utility ownership of property does not suffice as grounds for charging the cost of that property to utility customers. Rather, regulators have required that rate base include only utility plant that is both "used" to provide service, and "useful" (i.e., necessary), in order to ensure that utility rates cover only the cost of plant actually needed to provide utility service. This implies a potential disallowance of the cost of plant no longer "used" due to loss of sales to competitors. While utilities have argued that this is unfair, traditional economic and financial principles would suggest that it is a common business risk in any enterprise.

In the utility sector, the regulatory imposition of a "used-and-useful" standard mirrors competitive market conditions by preventing utilities from earning profits on plant that is deemed worthless or unreasonably excess to actual requirements. The application of the used-and-useful standard therefore serves to simulate in the utility sector some of the consumer protection and incentives for management efficiency that exist in competitive markets, where investments do not earn revenues unless they are actually used to produce products that are sold to consumers.

A strict application of the used and useful standard can conflict with the view that prudently incurred costs should be fully recoverable from utility ratepayers. The prudence standard, as generally applied, focuses on the reasonableness of utility management's conduct at the time the decision to incur the cost was made. The prudence standard implies that, if management acted reasonably based on the information available, full cost recovery should be granted regardless of the actual outcome of the management decision. That, of course, is not what happens in competitive markets, and, therefore, the prudent cost standard, where applied in this fashion, is admittedly a departure from the notion that regulation should impose a competitive-like discipline and end result in public utility markets. The prudence standard, carried to its logical conclusion, would allow investors to fully recover excess capacity costs of an unlimited magnitude, provided that the management decisions that led to the excess capacity are found to have been prudent at the time they were made.

A "reasonable opportunity" for a utility to recover its prudently incurred costs has been said to be part of a "regulatory compact" between utility investors and regulators.[66] That is, for the quo of a monopoly franchise and a reasonable opportunity for recovery of prudently incurred costs, regulators extract the quid that utilities are constrained to no more than a "reasonable" rate of return and are obligated to serve the public.

In addition to a certain intuitively appealing equitable balance, the "regulatory compact" quid pro quo also draws support from the alleged exigencies of financial markets. Unquestionably, utilities cannot fulfill their obligation to serve the public unless they have adequate access

66 See, e.g., the FERC's Opinion and Order, New England Power Company, Docket Nos. ER85-646-001, et al. (January 1988).

to the typically large amounts of financial capital required to do the job. But, according to the financial rationale for the "regulatory compact", investors will not supply the required quantities of capital at reasonable rates of return if regulators do not place constraints on the potential for capital loss that are commensurate with the constraints placed on utility profits and capital gains. According to this argument, limiting cost disallowances to costs that have been imprudently incurred is a practical requirement for adequate utility access to capital markets on reasonable terms.

The financial exigency argument against disallowing prudently incurred excess capacity costs was stated as follows by economist Kenneth Arrow on behalf of Commonwealth Edison Company in its recent rate case dealing with alleged excess capacity:

> Suppose that both of the following rules are followed: only investments "useful" in perfect hindsight are included in the rate base; and the cost of capital allowed on the rate base is the market rate of return (in addition to the recovery of investment through depreciation). Then any capital invested will earn, <u>at most</u>, the market rate of return. However, any time the prudent investment yields excess capacity, an event which can occur with significant frequency, the return on investment will be <u>less</u> than the market rate (in fact, zero on the excess part). Therefore, over time the actual rate of return on total investment will be less than

> the market rate. Clearly, no investor with access to alternative investment possibilities will invest in such an enterprise.[67]

In arriving at this conclusion, Arrow did not encumber his analysis by expressly recognizing that utilities' market cost of capital already includes a risk premium for expected losses such as excess capacity disallowances. Given this real world complication, Arrow's logic is less compelling.

The financial exigencies that supposedly underlie the "regulatory compact" must also be weighed against the increasingly pressing practical requirements of competitive utility markets. Prudent management cannot always be equated with efficient management. Prudence is, at bottom, a legal concept; it is "carefulness, precaution, attentiveness, and good judgment"--the opposite of negligence.[68] But, from an economic perspective, management is "efficient" to the extent that it produces service of adequate quality at the lowest possible cost, whether or not management is "careful," "attentive," or otherwise "prudent". It is possible, if unlikely, for an imprudent manager to achieve an efficient result. However, it is not only possible, but not all that unusual, for a prudent manager to produce an in-

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67 Kenneth Arrow, Testimony on behalf of Commonwealth Edison Company, before the Illinois Commerce Commission, Case No. 87-0427 (1987), pp. 6-7.

68 Black's Law Dictionary, as quoted in Robert E. Burns, et al., op. cit., p. 20.

efficient outcome, such as excess capacity. Caution, care, and good judgment usually accompany, but do not assure, efficiency.

Customers base their consumption decisions on the end-result of management--the quality and price of utility service--and are generally indifferent to the degree of prudence with which the end-result was achieved. Likewise, where prudence is the regulatory test for recovery of costs, utility managements' incentives will not be precisely focused on the end-result that customers require--efficient service--but on the manner in which management conducts its decision making process.

An additional problem with a prudence standard is that it encourages management decision-making procedures that tend to be distorted by the evidentiary requirements of the utility ratemaking process. For purposes of documenting prudence in future rate proceedings, written studies produced from files may, for example, be perceived by utilities as having more evidentiary credibility than utility executives' recollections of thought processes or oral discussions that occurred years in the past. The result may be to encourage a resource planning process that relies excessively on the mechanical application of quantitative models that can be reduced to paper and produced in rate proceedings to document prudence, and a corresponding excessive reluctance on the part of utility management to override quantitative studies in favor of non-quantifiable judgmental factors.

The effects of this bifurcation between the objectives of management and the requirements of customers will always be potentially undesirable, but may be especially adverse in circumstances where utilities face significant competition. Customers with the capability to do so will avoid paying for excessive utility costs that were prudently incurred by taking service from more efficient competitors that have avoided such costs. As a result, the remaining captive customers will be unfairly saddled with an even heavier burden of excessive costs. Moreover, if competitive conditions are sufficiently intense, the attempt to recover such costs through higher rates may cause a "death-spiral" of contracting demand and rising unit costs that effectively prohibits full cost recovery. Several interstate gas pipelines have alleged that such competitive conditions actually prevail on their systems.

Thus, whether or not prudence as the sole standard for cost recovery was ever economically well-conceived, it is unsuited to many situations in the present day utility industry. For these reasons, judging the "prudence" of utility management decisions should be a relevant basis of management evaluation insofar as a prudence test is the best available means of assessing management compliance with the more fundamental regulatory objective of economically efficient performance. Results-oriented standards for cost recovery, such as the used-and-useful standard, will more rationally focus regulatory incentives on the desired utility behavior (i.e, economic efficiency), and will more nearly simulate the economic efficiency incentives that characterize competitive markets.

### B. Sunk Cost Disallowances and the Cost of Capital

A policy of denying full recovery of sunk costs obviously implies a greater risk of financial loss for utilities than would exist if sunk cost recovery were assured. Investors are well aware that such a policy increases financial risk, and, accordingly, they establish a rate of return requirement reflecting that risk. The regulatory use of market-based measures of the cost of capital, such as the discounted cash flow method, incorporate this capital cost in utility rates.

Therefore, a significant policy trade-off in dealing with sunk costs is the effect of disallowing such costs on the cost and availability of capital. In fact, assuming investors are risk-averse--i.e., would prefer a certain outcome to an uncertain one even when the expected returns in both cases are the same--the increase in the cost of capital caused by disallowing excess plant costs may theoretically exceed the expected losses to investors from disallowance. Stated somewhat differently, it is theoretically possible that the increased cost of capital to consumers, as a result of policies disallowing excess sunk cost recovery, could exceed the expected direct savings to consumers from disallowing these costs.

However, these observations do not imply that correct regulatory policy should assure recovery of excess sunk costs where a policy of disallowing them would cause the cost of capital for utilities to rise. If minimizing the cost of capital were the overriding goal of regulation, the goal could most effectively be achieved by adopting policies designed to effectively guarantee that the achieved rate of return for utilities would always equal the authorized rate of return based on the market cost of capital. In that event, utility capital costs would tend to decline to a level approaching that associated with a risk-free security. But such a policy would entail foregoing the traditional regulatory prerogative of disallowing unreasonable costs, and would therefore virtually eliminate the incentives of utility stockholders and managers to avoid such unreasonable costs. Regulators have traditionally concluded that this would be a poor trade-off.

Moreover, even assuming that increased capital costs would exceed disallowances of excess sunk costs because of the risk-aversion of stockholders, it still does not necessarily follow that disallowance is, on balance, adverse to ratepayers' welfare. It must be considered that ratepayers may also be risk-averse. Only in the unlikely event that ratepayers are more risk-tolerant than the common equity shareholders of utilities will ratepayers prefer to assume the burden of excess sunk costs rather than paying the increase in the cost of capital required to compensate investors for assuming the risk.

Stated another way, the benefits to ratepayers of requiring investors to assume the risk of sunk costs may be analogous to the benefits derived from an insurance policy. Most homeowners insure their homes against fire damage. Yet the aggregate value of premiums received by insurance companies (including interest on undistributed funds) must exceed their expected payout for fire damage, or no insurance company would perceive fire insurance to be a profitable enterprise. Still, the homeowner judges the insurance to be in his interest, because he is risk-averse and wishes to exclude even the small probability of major financial loss resulting from uninsured fire damage.

The argument that disallowing the recovery of prudently incurred excess sunk costs will deny utilities reasonable access to capital markets appears to be mistaken. Most electric utilities, including those with massive construction programs, maintained adequate access to financial markets throughout the recent construction cycle, despite the turbulence that existed in the bond and stock markets during much of that period. During that period, even utilities that absorbed, or were anticipated to absorb, large sunk cost write-offs were able to raise new capital for new investments that were expected to be needed. This is not surprising in that investors are forward looking and current capital cost and availability are more directly dependent on expectations than on past events. Indeed, some utility companies found that their financial posture improved and capital costs actually declined after they wrote off excess sunk costs and put those concerns behind them.[69]

Even assuming that investor willingness to finance more large utility construction projects has become less assured in recent years, this does not mean that inefficiently but

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69 See, for example, Pacific Power & Light Company, 1983 Annual Report to Stockholders, at page 22.

prudently incurred costs should be guaranteed recovery. Investor reluctance to finance a project is a marketplace verdict on the economic viability of the project. There is no reason to believe that investors are incapable of sorting out which projects are good investments for a utility company and which are not. A construction project will be a good investment for a utility if it develops the project on a timely basis (i.e., corresponding to market demand) at a cost that regulators and customers perceive to be reasonable. If investors, who have every incentive to objectively assess the cost-effectiveness of a construction projects, refuse to advance the funds needed to finance the project, that is a significant indication that the project itself is economically dubious.

Stated somewhat differently, the economic wisdom of a particular construction project is not affected by who bears the risk that the project will fail. If a plant is a poor investment for stockholders, it is not likely to be a good investment for customers. The counterpoint to this argument is that unreasonable sunk cost disallowances policies may make prospectively beneficial investments "bad" for investors because of the risk of disallowances based on hindsight. That is true, but the key is "unreasonable". As discussed above, especially since unregulated competitive markets do not permit the recovery of excess sunk costs, disallowing these costs in regulated markets seems reasonable and not inconsistent with the risks to which investors are accustomed.

To override the verdict of capital markets, and force-feed capital into projects by assuring that excess costs, if "prudently" incurred, will be recovered, would tend to invite white-elephant projects that investors would be unwilling to support if their money were really at stake. The experience of a number of well-publicized utility construction fiascos in recent years illustrates that this is more than a mere theoretical risk. If regulatory and financial incentives had more quickly shut off the funds to dubious nuclear and gas supply expansion projects in recent years, our economy would have avoided many billions of wasted dollars. By shielding utilities from the disallowance of excess sunk costs, regulators would greatly increase the risk that such experiences will be repeated.

Thus, although allowing utility shareholders a reasonable opportunity to recover costs is appropriate for both equitable reasons and to assure utilities' continued reasonable access to capital markets, a singular focus on the shareholders' entitlement to a fair return would be unreasonable. Both the customers' interest in regulatory protection against excessive charges and the goal of stimulating shareholder incentives to discipline inefficient management are also important regulatory objectives.

### C. Customer-Stockholder Allocations of Sunk Costs

Regulators who contemplate assigning sunk costs to ratepayers (rather than stockholders) should consider the impact of the resulting rate increase on the quantity of service demanded by remaining customers--especially where the excess capacity resulted from uncompetitive rates in the first place. In the electric and gas industries, competition generally focuses on attracting new loads, retaining industrial customers who have alternate supply capabilities, or expanding the existing loads of industrial firms that are in competition with rivals in other utility service territories. While the ability of individual residential and small commercial customers to choose among competing electricity suppliers is generally limited to the collective franchise choices of their local governments, many large industrial power consumers consider competitive electric rates in making plant location and expansion (and, recently, closing) decisions.

In all three major regulated utility industries, it is clear that attempts to increase rates to recover the sunk costs of capacity rendered excess by already uncompetitive rates may fail to generate the desired revenues unless the rate increases are focused on "captive" customers that have relatively low price elasticities of demand. The potential inequities and economic distortions of this expedient are manifest. First, "captive" customers (generally the small commercial and residential classes) are the most vulnerable to the monopoly power of utility companies, and thus presumably the most in need of regulatory protection. Second, captive customers are not the "cause" of the excess capacity problem (since they, by definition, have not and cannot depart the system), and thus arguably should not be burdened with excess capacity costs on equitable grounds and on the basis of "cost-causation" principles.

Attempts to overcome this dilemma generally take two forms. One obvious solution is to simply deny recovery altogether--but this understandably meets with vehement utility opposition, and may be unacceptable for legal or policy reasons, as discussed above.

Another frequently proposed means of sparing remaining customers the cost of excess capacity resulting from sales losses is to devise a "purchase deficiency" charge for customers who have reduced their purchase quantities or "exit fees" for customers who are departing the system entirely.

A number of FERC-regulated pipeline companies have been the most visible proponents of this approach as a means of disposing of massive "take-or-pay" buyout and contract restructuring costs while avoiding either a "death spiral" of contracting demand, or bankruptcy, or both. The equity rationale for this approach centers on the contention that the costs in question were incurred by the utility for the benefit of the departing customers, who therefore should pay for them. Additional support for such purchase-deficiency based charges derives from the theory that, by departing the system, or reducing consumption, customers "cause" excess capacity costs, and should therefore be assessed such costs on the basic "cost-causation" principle of cost allocation.

Deficiency-based charges, however, are highly problematical in a number of respects. Because they assign costs based on past purchase levels, they can be attacked as a form of retroactive ratemaking. In addition, utility companies generally incur costs to serve an ever-changing aggregate of customers, not a set of specific customers with specific requirements. Absent some rational basis for determining the "correct" consumption level for a given customer, it is possible to argue from pure economic theory that customers who reduce purchases are no more responsible for excess costs than other customers who "failed" to increase purchases, or who elected not to receive service at all.

Regulators most commonly resolve the competing policy concerns involved in disposing of sunk costs by compromise--i.e., some formula for sharing sunk costs between stockholders and ratepayers. The FERC's policies of disallowing 50 percent of take-or-pay buyout costs for interstate pipeline companies that wish to employ direct billing for cost recovery, and disallowing 50 percent of abandoned electric production plant costs, typify this approach. The usual rationale for such policies is that allowing partial cost recovery moderates the adverse impact on consumers or utility financial stability that would occur under policies of full recovery or disallowance, yet maintains utility incentives for efficient operations by imposing a significant responsibility for the excess cost on utility shareholders.

The penetration of competitive forces into the utility sector requires reassessment of traditional cost recovery policies. Improved regulatory policies for dealing with sunk capacity costs must start from the recognition that a loss of business volumes to competitors can result from a number of underlying causes, each of which may call for a different regulatory response. The policy of equal stockholder-ratepayer sharing of excess cost responsibility attempts to be fair to both sides, and in fact achieves the appearance of judicious balance. However, less arbitrary methods of assigning sunk cost responsibility can be devised, and may be particularly appropriate when the utility faces significant competitive pressures. For such firms, an overly arbitrary policy, such as an equal stockholder-ratepayer sharing of excess capacity costs, may lead to uneconomic distortions of utility prices and even further sales erosion.

Assigning an increased share of excess sunk costs to stockholders would be especially desirable for utilities that have incurred such costs as the result of management error (even when "imprudence" was not a key factor). Excessive sunk costs are unfortunately a common source of competitive problems for utilities, particularly for electric utilities that have experienced construction fiascos and natural gas companies that are attempting to dispose of massive overcommitments to increased gas supply. Such utilities lose business for the simple reason that they have raised prices to an uncompetitive level in attempting to recover excessive costs. Where such circumstances prevail, an attempt to make utility stockholders whole by increasing prices further simply exacerbates the erosion of business, to the detriment of both the utility and remaining customers.

The appropriate regulatory response where erroneous management decisions were responsible for sales losses is a relatively large or even a full assignment of excess sunk costs to shareholders. For the reasons discussed in the foregoing analysis, such a policy is both justified and necessary in order to maximize incentives to bring costs into line with competitive market requirements.

Excess capacity can also be created by poorly structured prices for the utility's output, which can artificially depress and/or distort the sales volumes of even utilities with optimally efficient capital investments. Faulty rate designs that underprice certain services and overprice others, relative to their costs, are a frequent cause of uncompetitive prices and depressed sales of the overpriced services. This can result in an overall revenue deficiency for the utility, particularly where the price elasticity of demand for underpriced services is less than for the services that are overpriced. There are also problems even where overall revenue deficiencies are not an issue because overpricing in one market offsets underpricing in another. This is an especially important concern for utilities such as diversified telephone companies that operate in both competitive and monopolized markets. If, for example, such utilities have the flexibility to charge excessive system costs to captive basic exchange service customers to make up for the underpricing of competitive services such as Centrex, the end result will be to distort both markets and perpetuate wasteful investment practices.

The appropriate response to faulty rate design involves neither disallowances of costs nor an increase in the average unit rate, but a rate restructuring that will ultimately reduce the excessive costs of serving subsidized markets and expand sales volumes in markets that were previously overpriced.

A third potential source of unused utility capacity is the development by customers of the technological capability to provide traditional "utility" services in-house on a more economically efficient basis. Perhaps the most common current example of this is industrial firms that develop cogeneration utilizing waste energy from industrial processes. Another possible example is "economic bypass" in the telecommunications industry.

Where such sales losses are due to technological advantages or other externally imposed conditions that could not have been averted by even the most efficient utility management or the most accurately cost-based rate design, there is little that regulators can or should do to attempt to arrest sales erosion, assuming the utility is otherwise efficient and rate design is economically justified. Such "economic bypass" results in the socially most efficient allocation of resources, and any successful regulatory effort to thwart such bypass would only reduce overall economic welfare.

But, even when bypass is economic, the utility can experience an excess capacity cost, and regulators must confront the question of who absorbs it. In this instance, the equitable and economic case against full cost disallowance is far more persuasive than when management inefficiency is involved. There is obviously no economic incentive argument for full disallowance, since utility inefficiency is not the cause of the excess sunk cost.

A reasoned determination of how such excess capacity costs should be allocated between ratepayers and investors will likely involve a case-specific regulatory assessment of the competitive posture of the utility as well as equitable considerations. A reasonable presumption might be that those excess sunk costs imposed entirely by external forces and for which utility management bears no responsibility should be shared equally between ratepayers and stockholders on equity grounds. However, if the utility's remaining business is unusually price-elastic, that ratio might be tilted more heavily toward stockholders. Conversely, if the utility's market position will not be substantially harmed by charging excess innocently incurred sunk costs to remaining customers, that may warrant more than a fifty percent cost recovery.

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