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CURRENT PGA AND FAC PRACTICES: IMPLICATIONS FOR RATEMAKING IN COMPETITIVE MARKETS

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EXECUTIVE SUMMARY

This report addresses two concerns. The first concern was sparked by inquiries received by The National Regulatory Research Institute and the Washington Offices of the NARUC about current state electric fuel adjustment clauses and purchase gas adjustment clauses. Part of this report summarizes and discusses the current fuel adjustment clause and purchase gas clause practices of the fifty state commissions and the Federal Energy Regulatory Commission. The second concern was that state commissions might find it appropriate either to defend or improve their current practices in light of evolving, more competitive electric and gas markets. Knowledge gained about current state commission practices forms the foundation for research as to how and whether current state commission practices might be improved given more competitive markets.

Traditionally, automatic adjustment clauses have been generally accepted as a part of a utilities' tariffs for three major reasons. First, the item, whether it be gas, coal, labor cost, interest, or some other cost, constituted a significant or large component of the utility's total operating cost. Second, the cost changes with respect to that item were volatile and unpredictable. Third, the purchased items (commonly fuel or purchased power) were entirely outside of the utility's control. In recent years, the issue has been raised as to whether these conditions still hold. Clearly, fuel and purchased gas costs, while down from peak levels, still constitute a significant portion of a utility's operating costs. It is a good deal less clear that fuel costs are currently volatile and unpredictable. For some time now, fuel prices have not been as volatile and uncertain as in the past. But, can we expect the relative calm of recent years to continue? Probably not.

Instead, increased volatility and unpredictability in gas and coal prices can be expected in large part because of the requirements of the Clean Air Act Amendments of 1990. The United States Energy Information Administration predicts that electric utilities will place heavy reliance on gas, nonutility generation (usually gas-fired) as well as low-sulfur coal for future generation. Increased utility gas consumption could have a profound effect on fuel adjustment and purchased gas adjustment clauses.

Unless a utility is vertically integrated so that it owns its own fuel or purchased power supply sources, it exerts little control over the cost of fuel or purchased power. However, this does not mean it exerts no control whatsoever, or is excused from hard-nosed, tough bargaining. Indeed, at the margin a prudent utility would incur costs in searching for less expensive fuel supplies equal to its expected benefits, which are defined as the expected cost savings.

For fuel and purchased gas adjustment clauses, the three grounds for having an automatic adjustment clause still hold, except when a utility owns an affiliated fuel or power source. But, the current trend is toward more open markets, evidenced in the electric sector by more bulk power purchases (including those from QFs and IPPs), and evidenced in the gas sector by more direct gas purchases and the greater use of transportation services. The more competitive environment allows the utility to change its mix of resources in response to price changes. This creates a need to revisit automatic adjustment clauses to determine what incentive they create and what their ratemaking implications are in a more competitive environment.

The traditional three criteria for the continued use of automatic adjustment clauses for fuel and power purchases, while still necessary, are no longer sufficient in a more open market environment. An additional criterion requires that any automatic adjustment clause should provide incentive compatibility in a more open market environment. In other words, automatic adjustment clauses in the new environment ought to be designed so that firms will act in their own best interest, maximizing profits by minimizing costs, while passing through some of the benefit of decreased fuel costs to customers. Said another way, clauses should be designed to promote efficient behavior on the part of the utilities, while quickly and accurately passing through fuel price changes to customers so they can make rational choices about supply, consumption level, or purchase of substitute goods.

There is a need to redesign state FACs and PGAs to meet this final criterion. Indeed, most state commissions have not altered their PGAs and FACs in any significant manner to accommodate today's competitive environment. A "fixed-weight method" of designing PGAs and FACs is described that meets the criterion of incentive compatibility. It would have the advantage of providing appropriate incentives for utilities to engage in least-cost procurement in competitive markets while mitigating distorted price signals to the consumers.

The "fixed-weight method" could provide state commissions with an appropriate conceptual model on which appropriately redesigned FACs and PGAs could be based. The "fixed-weight method" is introduced in this report as a framework for the recovery of costs that currently pass through state PGAs and FACs. Special attention is given to the features of the method that can potentially foster long-standing regulatory objectives in an environment where competition has become more prevalent. The reader should be cautious not to view the "fixed-weight method," in its present form, as fully developed for immediate adoption. The authors understand the many questions that regulators must address, which were either ignored or touched on cursorily in this report, before resorting to a different ratemaking mechanism.

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FOREWORD

With the advent of more competitive electric and gas markets our Board of Directors felt it would be useful to revisit fuel adjustment clauses to see how they fit in that environment and how they might be improved. The three traditional criteria for introduction of automatic adjustment clauses in the first place are reviewed for their current applicability. An additional test is suggested, i.e., compatibility with promoting efficient behavior by utilities in their purchases. It was thought to be time for an update on the practices and operations of adjustment clauses around the country. Attention is given to both the design and monitorship of these devices.

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CHAPTER 1

THE OCCASION

Fuel adjustment mechanisms were first used in the United States during World War I when coal prices escalated. After a return to normalcy following the War, their use fell off. However, World War II and the immediate post-War period with its associated inflation resulted in renewed use of fuel adjustment clauses in rate cases. After a relatively quiet period during the 1960s, they became commonplace, particularly after the 1973 oil price shock.[1]

The history of purchased gas adjustment clauses, while not as long, is similar. Purchased gas adjustment clauses became widespread after the 1973 oil price shock, as local distribution companies needed to adjust quickly the price of gas purchased from the pipeline.

Automatic adjustment clauses have been generally accepted as a part of a utility's tariff for three major reasons. The first is that the item, whether it be gas, coal, labor cost, interest, or whatever, constituted a significant or large component of the utility's total operating cost. The second is that the cost changes with respect to that item were volatile and unpredictable. The third is that the purchased items (most commonly, fuels) were entirely outside the control of the buying utility.[2] Many contend that for automatic adjustment clauses to be justified all three conditions must hold. Thus, if one of the conditions did not hold, such as volatile and unpredictable cost changes, that was grounds for reexamining whether an automatic adjustment clause was still needed. Others argue that the lack of one of the three conditions is not sufficient by itself to lead to its reconsideration and/or repeal. One authority suggests that we take advantage of the current regulatory window of relative calm--a

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[1] Kevin Kelly, Timothy Pryor, Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, OH: The National Regulatory Research Institute, 1979), 1-4; R. S. Trigg, "Escalator Clauses in Public Utility Rate Schedules," *University of Pennsylvania Law Review* 106 (1958): 964-97.

[2] See Kelly et al., *Electric Fuel Adjustment Clause Design*, 8.

relative calm at least in terms of the number, size, and frequency of general rate cases--and revisit whether automatic adjustment clauses are still justified.[3]

Since shortly after the implementation of the Public Utility Regulatory Policies Act of 1978, there has been no thorough and complete study of the current FAC and PGA practices of the state commissions. The first part of this report, Chapters 2 and 3, contains such a study.

In the second part of the report, Chapters 4, 5, and 6, we examine the use of fuel adjustment clauses, purchased gas adjustments, and other automatic adjustment clauses to determine whether they are still appropriate in a more open market environment. This question differs from the question of whether they are still appropriate according to the original three grounds. We provide a brief examination of those questions here.

Do fuel and purchased gas costs still constitute a significant component of a utility's total operating costs? While fuel and purchased gas costs are generally down from their peak levels,[4] they still constitute a significant proportion of a utility's operating costs.[5] Most other variable costs do not represent a significant proportion of a utility's operating costs, and hence, are not candidates for an automatic adjustment clause. Still, some contend that in the extreme case, where the cost item is almost impossible to predict and is entirely beyond the control of utility management, an automatic adjustment clause is justified.

Where adjustment clauses are still in effect, they usually have some other purpose. For example, many of the "ERAM-style" (electric revenue adjustment mechanism) adjustment clauses, such as those found in California and New York, are meant to streamline the regulatory process and prevent the utility from coming in for frequent rate cases, as well as to promote demand-side management and conservation

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[3] See Douglas N. Jones, "Taking Advantage of a Regulatory Window," *Public Utilities Fortnightly* (July 20, 1989), 22-25.

[4] See Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (91-01) (1991), Table 9.11.

[5] *Edison Electric Institute Statistical Year Book of the Electric Utility Industry, 1990* (Washington, D.C.: Edison Electric Institute, 1991).

programs and eliminate financial volatility of earnings due to unanticipated sales gains or losses. While some benefits certainly are to be gained from such streamlining, they may impose costs that need to be considered.

Are the cost changes associated with fuel costs still volatile and unpredictable, dramatically changing up and down during short periods of time? While we have not formally studied the degree of volatility of fuel prices, informed observation would lead one to conclude that fuel prices are not as volatile as they were in the past. In particular, the fuel cost run-ups of the late 1970s and early 1980s have subsided and fuel costs have actually come down in some areas. Can this calm be expected to continue? Perhaps not.

In its 1988 report on international energy consumption, the United States Energy Information Administration (EIA) reported that gas will be the fastest growing fossil fuel in the world as the United States, Canada, and other countries increase their use to reduce both their dependence on oil and the environmental effects associated with other fossil fuels such as coal. Other factors influencing gas demand will include its price relative to other energy sources, the availability of capital to develop new sources and to construct required pipelines and new distribution systems, the development of more open markets, and overall economic growth. The EIA's projections so far seem to be on track. In its 1991 report on the Annual Outlook for United States Electric Power, the EIA projects that natural gas is expected to be the fuel of choice for many new capacity additions over the next decade. One-third of the 73 to 104 gigawatts of electricity capacity additions brought into service by 2000 could be fueled by natural gas. According to a Gas Research Institute report, gas will fuel 4.8 quads of electricity in 2010, up from 2.9 quads in 1990, and that United States' consumption will grow to 20.7 Tcf in 1995, up from 18 Tcf in 1988. Because of this increased demand for gas, it is expected that the price of gas will increase in the future. In the original EIA report, it was estimated that consumption in 2000 would hit 22.9 Tcf, decreasing slightly to 22.2 Tcf in 2010. The EIA also forecasts that average wellhead prices in 1989 dollars will be $1.79 per Mcf in 1990 (the actual 1990 price was $2.19), rising to $3.38 per Mcf in 1995, and $4.31 per Mcf in 2000 before falling back to $3.59 per Mcf in 2005. If these projections are even somewhat accurate, we might expect renewed volatility of gas prices as gas becomes the fuel of choice to meet more stringent environmental regulations.

We also might expect increased volatility in coal prices because of the Clean Air Act Amendments of 1990 (CAAA). While the price of low-sulfur coal has been relatively stable in recent years, the CAAA will have the effect of placing a premium on low-sulfur coal causing firms to discount the value of high-sulfur coal because of the costs associated with burning it and remaining in compliance with the CAAA. Thus, we might also expect increased volatility in coal markets in the future as utilities change their coal procurement practices to comply with the CAAA.

Recall that our third ground for automatic adjustment clauses is that the utility has little or no control over operating expense, in this case fuel. Unless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel.[6] This does not mean that it has no control whatsoever, or that it is excused from hard-nosed, tough bargaining. Indeed, state public utility commissions often hold utilities to a standard of care of a prudent business man in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause. In theory, at the margin a prudent utility would incur costs in searching for less expensive fuel supplies equal to its expected benefits, that is the expected cost savings. The conclusion seems clear that unless the utility owns an affiliated fuel source, it still has little or no control over the market price of fuel. However, it may have control of its total cost of fuel because it can change the mix of its fuel supplies.

Upon reexamining the three traditional bases for having automatic adjustment clauses, we have found that for fuel and purchase gas adjustment clauses the grounds still hold. In the old context there would seem to be little reason to revisit whether automatic adjustment clauses have outlived their usefulness.

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[6] Even if a utility is vertically integrated, owning its own fuel source, all intracorporate transfer costs may not be allowed by the PSC. This would be the case if the company's fuel costs were substantially greater than alternate sources of supply. See Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986).

The current trend is toward more open markets in gas and electricity. The gas industry has faced a more open market since FERC Order 436. Today, local gas distribution companies have the option of buying gas directly from producers, as well as from pipelines. Likewise, in most states, industrial and other end users are also permitted to buy gas directly from producers. In the electric sector a more open market is evidenced by more bulk power purchases from nonutility generating (NUGs) projects, both from qualifying facilities and independent power producers. In the United States, a regulatory environment favoring certain NUGs known as qualifying facilities was created by the Public Utility Regulatory Policies Act of 1978 (PURPA). Since then, many state public utility commissions have experimented with competitive bidding for new power sources, which has given rise to other NUGs known as independent power producers.

The current trend toward more open markets in gas and electricity creates a need to revisit automatic adjustment clauses to determine what incentives they create and their ratemaking implications in a more competitive environment.

The more open market environment raises several issues and questions. For purchased gas adjustments, the issues include whether take-or-pay liabilities should be passed through; whether gas transportation customers who only buy transportation service from the pipeline and buy gas from the producer should be subject to take-or-pay liability; how the various customer classes, particularly core residential and small commercial customers, are affected; whether the PGA policy encourages bypass of the local gas distribution system; whether affiliated gas suppliers are treated any differently; how PGAs affect the seasonality of gas cost, incentives for gas storage, transportation service rates, back-up services, and the availability of unbundled gas supplies for direct purchase by local distribution companies and end-users or both; and what gas price escalation provisions, if any, are appropriate for a distribution company that contracts directly with the gas producer. These issues are addressed in Chapter 4.

One difficult problem sometimes created by the operation of a fuel adjustment clause is that capital costs could be added together with fuel costs when power is purchased from nonutility generators.[7] Other issues include: given a more competitive environment, what criteria should be applied today to determine the appropriateness of fuel adjustment clauses and purchased gas adjustments?

Concerning FACs, what are the regulatory implications of various types of FACs for ratemaking in a more open electric market? In particular, what are the implications of passing through capacity costs as part of a fuel adjustment as more nonutility generators come on line? Does it skew a utility's evaluation of whether to buy from that source? If competitive bidding is used to select additional power sources, does it skew the bidding criteria and evaluation? Does the policy encourage uneconomic self-generation? What effect do the FACs have on customer class cost allocations? How are core classes (residential and small commercial customer) affected? If there are affiliated NUGs, how are they treated by the utility: preferentially or with a hard look? Finally, what kind of electric fuel cost adjustment clause, if any, is appropriate for power purchased from NUGs that win competitively bid power supply contracts? These issues are addressed in Chapter 5.

One state commission that implemented competitive bidding early on issued guidelines on the treatment of purchased power capacity charges. The Virginia State Corporation Commission has rejected including capacity charges incurred in the purchase of reliability, that is, firm, as opposed to economy (or availability) power. Their rejection is dictated by a desire to maintain appropriate regulatory oversight while creating proper incentives for efficiency in power purchases from NUGs. The Virginia Commission is opting for a rate-case scrutiny, with its potential for a comprehensive prudence review, to assure that the capacity costs or purchased power is appropriate.

In its first report on competitive bidding, the NRRI suggested that for long-term purchased power contracts, the energy costs are probably not predictable, and that NUGs have only limited control over price fluctuations. For energy costs, FACs,

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[7] An economy power purchase may include capital costs in addition to fuel costs up to the purchasing utility's incremental (avoided) costs. Increasingly, nonutility generators are seeking market-based rates that combine capital and fuel costs together. As shown in Chapter 3, in some states both are combined and flowed through a fuel adjustment clause.

perhaps with incentive provisions, still may be appropriate. For its own capacity and other nonenergy costs, the NUG has greater control. So, to avoid a "moral hazard" condition (where there is no penalty but only reward for taking risks because the penalty for loss is borne by others), a fixed-price approach to capacity payments is desirable. Similarly, North Carolina, Texas, and Hawaii exclude capacity charges for purchased power from FACs. On the other hand, New Jersey includes them.

As mentioned, the current trend is toward more open markets in electric and gas evidenced by more bulk power purchases, qualifying facility (QF) and independent power producer (IPP) production, competitive bidding, and pipeline and local distribution company (LDC) gas transportation service. Given this more competitive environment, one could argue that LDCs have considerably more control over their purchase gas costs than just a few years ago. Thus, assuming all other things are held constant, one might argue that PGAs are less supportable today than in the recent past. A reexamination of current FAC and PGAs is needed to determine what incentives they create and their ratemaking implications in this new more open market environment.

The more open market environment in both the electric and gas industries suggests that another criterion is necessary for the continued use of automatic adjustment clauses for fuel purchases. The additional criterion would address the problem of possible perverse incentives that an automatic adjustment clause would have on utility behavior in today's more competitive environment. What probably should be avoided is an automatic adjustment clause that gives the utility either an incentive to engage in anticompetitive activity or an insufficient incentive to engage in least-cost purchasing to develop an optimal portfolio of contracts. As an example, an incentive for a gas LDC to shift costs from noncore customers who are capable of switching to transportation service to core customers who are not may reflect anticompetitive behavior. A PGA that allows for shifting of costs from an elastic customer class to an inelastic one could be considered anticompetitive if it allows the LDC to charge core customers costs that are associated with the cost of serving noncore customers.[8] An example of an automatic adjustment clause that creates no incentive to engage in least-cost purchasing might be an FAC that allows a utility to pass through all purchased power costs that result from competitive bidding. With such a clause in place a utility might tend to favor external construction over its own, even if it were the low-cost builder; it also might create a bias in selecting projects, possibly tending to favor fuel-intensive projects over capacity-intensive ones because fuel costs would be passed through automatically while it may be more difficult to recover capital costs.

As shown in Table 1-1, there should be an additional criterion for the continued use of fuel and purchased gas adjustment clauses, namely, the operation of any automatic adjustment clause for fuel purchases should provide incentive compatibility in a more open market environment. In other words, an automatic adjustment clause ought to be designed so that the firm will act in its best interest--maximizing its profits by minimizing its fuel costs--while passing through some of the benefit of decreased fuel costs to the customers. Fuel price changes to customers should be passed through quickly and accurately so that customers can make rational choices as to their choice of supply, consumption level, or purchase of substitute goods.

An automatic adjustment clause should be designed to promote, or at least not discourage, efficient behavior by the utility. The clause should be designed so that the utility will engage in cost minimizing behavior. (Retail prices to customers could then be set at a competitive level, because they would reflect the utility's cost minimizing behavior.) Efficient utility behavior would result in a utility constantly readjusting a diversified portfolio of inputs to minimize costs.

If a fuel or purchased gas adjustment clause results in anticompetitive utility behavior or in a utility not procuring best-cost fuel in the more open competitive markets, then there is reason at least to question the continued use of the automatic adjustment clause. Perhaps, the automatic adjustment clause can be redesigned to be

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[8] See J. Stephen Henderson and Robert E. Burns, *An Economic and Legal Analysis of Undue Price Discrimination* (Columbus, OH: The National Regulatory Research Institute, 1989), Chapter 3.

TABLE 1-1

THREE CLASSIC REASONS FOR
AUTOMATIC ADJUSTMENT CLAUSES WITH A
NEW CONSIDERATION FOR MORE OPEN, COMPETITIVE MARKETS

THREE CLASSIC REASONS

1. The item constituted a significant or large component of the utility's total operating cost.

2. The cost changes with respect to that item were volatile and unpredictable.

3. The purchased item (most commonly fuels) were entirely outside the control of the buying utility.

THE NEW CONSIDERATION

4. The operation of any automatic adjustment clause for fuel purchases should provide incentive compatibility in a more open market environment.

Source: Authors and Kelly et al., *Electric Fuel Adjustment Clause Design*.

incentive compatible in a more competitive environment. If not, discontinuing the automatic adjustment clause should be considered. Chapters 4 and 5 also address how to design incentive compatible fuel adjustment and purchased gas adjustment clauses in a more competitive environment.

Before turning to the current status (state and federal) of FAC/PGAs it is well to recall some of the downsides of these mechanisms: the main advantage--rapid cost recovery--is easy to see. This is important because adjustment clauses for fuel inputs are not in fact time-honored cornerstones of regulation, but rather improvisations made by public utility commissions under stress. Many practitioners viewed them as transitory, to be removed from tariffs when price level changes quieted down. Also, there is big money involved in their operation. Billions of dollars are gathered through electric and gas adjustment clauses; often three to four times as much as results form general rate increases annually. Finally, this kind of "formula regulation" is particularly subject to interpretive and accounting abuse. Carefully designed clauses and vigilant monitorship are the main defenses available to regulators for these problems.

One problem with adjustment clauses is that distortions can occur in power production when utility managements make decisions influenced by the relative ease with which cost recovery can be realized. Expenses that flow through an FAC or PGA may be favored, as may be investments associated with them, because they are quickly recovered and do not have to stand the degree of scrutiny that a general rate case allows. Economists see this as hurting allocative efficiency in power and purchased gas supply.

A second problem is that focusing on a single cost of doing business and allowing full pass-through to customers can lead to revenue requirements for utilities that are unduly high. Not all costs move in the same direction all of the time, so that even if fuel costs have risen there may be actual declines in other cost factors arising from, say, tax decreases or productivity improvements. The setting of a general rate case facilitates this offsetting of increased costs with decreased ones, but the operation of adjustment clauses often does not.

Then there is the problem of misinterpretation and misapplication of adjustment clauses by utilities, either by inadvertence or design. What exactly is covered; by the clause and how it is reported can be arguable and open to mischief and misunderstanding.

Anther concern is that the longer fuel adjustment clauses exist, the greater the pressure for elaborating the mechanism into other areas. Automatic adjustment clauses have been proposed to cover changes in labor, interest, and tax charges, and a "comprehensive clause" was proposed in at least one jurisdiction. Water utilities have proposed similar clauses to cover the energy and the chemical components of water purification and supply.

Still another difficulty is making sure that FAC/PGAs operate in a truly symmetrical way, that is, that they are as quickly responsive in reflecting fuel price decreases as they were in price run-ups. If commissions are not assiduous in their attention to this, substantial overcollections by utilities can, of course, result.

A sixth problem in employing adjustment clauses is to provide an "end run" around the concept of full and fair evidentiary hearings that is a cornerstone of traditional public utility regulation. Even where the clause is not fully automatic and periodic reviews are provided for, this kind of post-hoc check does not afford the comprehensive and balanced examination that a full-blown general rate case does. Eroding the process by formula arrangements has a notable cost.

Finally (though not all agree), there is the view that adjustment clauses may do away with one of the most powerful incentives regulators have for inducing utility efficiency--regulatory lag. The argument goes that utility management is encouraged to seek cost savings through efficiency gains if it knows that it must wait until the next rate case to otherwise keep itself whole.

For all of this, FAC/PGAs continue to be part of the regulatory landscape. As mentioned, a main purpose of this report is to help improve their functioning in the current context.

CHAPTER 2

CURRENT STATE AND FEDERAL PURCHASED GAS ADJUSTMENT PRACTICES

This chapter describes state and federal utility commissions' purchased gas adjustment clause practices. The NRRI surveyed these agencies during 1990 to gather information on their current policies and procedures. Survey forms were sent to the public utility commissions in forty-eight states and the District of Columbia.[1] The authors also contacted the Federal Energy Regulatory Commission (FERC). Responses were received from all of these commissions. This chapter includes a summary of the survey results. Interested readers are also directed to Appendix A of this report for the survey instrument.[2]

The discussion in this chapter takes the following form. The next section covers the extent to which commissions are using purchased gas adjustment clauses. The following section covers commission procedures on local distribution company (LDC) filings. Subsequent sections cover costs allowed in the PGA and treatment of cost increases or decreases, required accounting practices, true-up and refund procedures, treatment of spot gas and direct gas purchases in the PGA, incentive mechanisms, and other PGA-related issues including LDC bypass, customer class allocations, transportation and back-up service rates, and affiliated gas suppliers. The final section contains a summary of the major findings of the survey.

Commission Use of Purchased Gas Adjustment Clauses

The survey began with several questions on the extent to which the commissions use purchased gas adjustment clauses and the manner in which PGAs are

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[1] Hawaii and Nebraska were excluded from the survey. The Nebraska Commission does not regulate natural gas local distribution companies. The Hawaii Commission had previously informed the NRRI that there was no natural gas in use in that state.

[2] Detailed survey responses are available in a separate volume on request to the NRRI Publications Office.

employed. The first question asked whether a commission has purchased gas adjustment clauses. Staff members at commissions where PGA clauses are used then were asked whether the PGA consisted of generic rules, orders, decisions, or cases providing for uniform treatment for all of the LDCs in a state or whether the commissions treat PGA on an ad hoc basis with each PGA varying from utility to utility. Responses to these questions are reported in Tables 2-1 and 2-2.

Table 2-1 shows that the vast majority of commissions do have purchased gas adjustment clauses. Only two state commissions, Michigan and Vermont, responded that they do not have PGA clauses.

In California, LDC purchases of gas for all customer classes were covered by the PGA beginning around 1974. LDC purchases for noncore customers were removed from the PGA and the distributor placed at risk as of May 1, 1988. Noncore customers, however, could choose an elected-core procurement option or sign a long-term contract with the distributor; these latter purchases then would be covered by the purchased gas adjustment.

In Utah, the two LDCs track their gas costs and make any adjustments through a pass-through procedure. A hearing is held every six to twelve months and any over or undercollection in "Account 191" is amortized over a twelve-month period.

Table 2-2 shows that while most commissions with PGA clauses have a generic rule, order, decision, or case that provides for a uniform procedure for all of the LDCs in the state, a significant number of commissions also treat PGA on an ad hoc basis. Twenty-seven commissions responded that they have a generic rule, order, and so on, while twenty said that they treat PGA ad hoc.[3]

Two commissions, Indiana and Mississippi, responded that they have a generic order, rule, and so on and that they also treat PGA on an ad hoc basis. The

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[3] Forty-eight commissions are listed in Table 2-1 as responding that they have PGA clauses. Forty-five commissions are listed Table 2-2 as using either a generic or ad hoc approach. (Indiana and Mississippi are listed in both columns and thus the column frequencies sum to forty-seven.) The three commissions listed in Table 2-1 but not in Table 2-2 are Colorado, Missouri, and North Carolina. These three responded that they use neither the generic nor the ad hoc approaches.

TABLE 2-1

COMMISSIONS THAT HAVE PURCHASED GAS ADJUSTMENT CLAUSES

Alabama	Missouri
Alaska	Montana
Arizona	Nevada
Arkansas	New Hampshire
California	New Jersey
Colorado	New Mexico
Connecticut	New York
Delaware	North Carolina
District of Columbia	North Dakota
FERC	Ohio
Florida	Oklahoma
Georgia	Oregon
Idaho	Pennsylvania
Illinois	Rhode Island
Indiana	South Carolina
Iowa	South Dakota
Kansas	Tennessee
Kentucky	Texas
Louisiana	Utah
Maine	Virginia
Maryland	Washington
Massachusetts	West Virginia
Minnesota	Wisconsin
Mississippi	Wyoming

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

TABLE 2-2

TYPES OF COMMISSION TREATMENT OF PGA

Commissions That Have a Generic Rule, Order, Decision, or Case Providing a Uniform PGA	Commissions That Treat PGA on an Ad Hoc Basis
California	Alabama
Connecticut	Alaska
District of Columbia	Arizona
FERC	Arkansas
Florida	Delaware
Illinois	Georgia
Indiana*	Idaho
Iowa	Indiana*
Kansas	Kentucky
Maine	Louisiana
Maryland	Mississippi*
Massachusetts	Montana
Minnesota	Nevada
Mississippi*	New Jersey
New Hampshire	North Dakota
New Mexico	Rhode Island
New York	South Carolina
Ohio	South Dakota
Oklahoma	Texas
Oregon	Utah
Pennsylvania	
Tennessee	
Virginia	
Washington	
West Virginia	
Wisconsin	
Wyoming	
(N=27)	(N=20)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

*Commissions responding that they have a generic rule, order, etc. providing a uniform PGA and that they also treat PGA on an ad hoc basis.

Mississippi Commission's rule[4] provides for automatic approval of some costs including adjustments for gross receipts and other taxes and for any increase or decrease in the cost of gas per unit sold over or under the cost of gas recovered under the current rate schedule. Additional costs can be recovered only with specific Commission approval.

The Wyoming Commission has a uniform PGA treatment for all jurisdictional LDCs although certain conditions may vary from utility to utility. (Amortization period is one such condition.) The Rhode Island Commission treats PGA on an ad hoc basis although all of the purchased gas adjustments are similar. In Pennsylvania, the PGA procedure varies with the class of utility. Group One utilities, those with intrastate revenues in excess of $40 million, are required to make annual PGA filings. Filings may be made voluntarily and must be submitted to the Commission six months in advance of the date when the tariff sheets are to take effect. Hearings are required for these Group One utility filings. This class of utility accounts for most of the gas sold in Pennsylvania.

Pennsylvania LDCs with annual intrastate revenues of less than $40 million may establish a sliding scale of rates for the automatic adjustment of the PGA. A tariff reflecting these rates must be filed with the Commission. No hearings are required for these filings. The Commission may on its own initiative hold a hearing and then establish a mandatory system for automatic adjustment. Each LDC subject to the order would then have to file a tariff reflecting the rate established by the Commission's order.

The NRRI then asked about the establishment and abolition of PGAs at the commissions. Staff members at commissions with purchased gas adjustment clauses were asked when the PGA was established. Was the PGA recently established (within the last five years) or was it long-standing (five or more years old)? As Table 2-3 shows, most PGAs are long-standing. In at least two instances (New York and the District of Columbia) the purchased gas adjustments date back to the 1950s. The Indiana Commission's original order for its Gas Cost Adjustment procedure was issued

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[4] Rule 48C of the Rules Governing Public Utility Service.

TABLE 2-3

COMMISSIONS WITH LONG-STANDING PGAs
(Over Five Years)

Alabama	Montana
Alaska	Nevada
Arizona	New Hampshire
Arkansas	New Jersey
California	New Mexico
Colorado	New York
Connecticut	North Carolina
Delaware	North Dakota
District of Columbia	Ohio
FERC	Oklahoma
Florida	Oregon
Georgia	Pennsylvania
Illinois	Rhode Island
Indiana	South Carolina
Iowa	South Dakota
Kansas	Tennessee
Kentucky	Texas
Louisiana	Utah
Maine	Virginia
Maryland	Washington
Massachusetts	West Virginia
Minnesota	Wisconsin
Mississippi	Wyoming
Missouri	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

in August 1983 with a final order issued in May 1986. The Oregon Commission used to have uncodified PGAs dating from the mid-1970s. With the rise of open access transportation, tariffed PGAs with a 20 percent incentive factor were implemented.

Tennessee had a purchased gas adjustment rule that went into effect in 1974. The Commission has enacted a new rule to replace the previous regulation.

In Idaho, PGAs were recently approved for the two jurisdictional LDCs but the Commission has allowed the utilities to track any increases or decreases in purchased gas costs since the mid-1970s. Those increases or decreases were due principally to changes in pipeline charges until recently. When the local distributors began to purchase gas from a variety of sources instead of just pipeline supply, PGAs became necessary.

The authors asked staff members of those commissions with no PGAs whether the commissions had such clauses at any time and when and why the PGA was abolished. Table 2-4 shows the three commissions that responded that PGAs had been abolished. The Vermont Board abolished its PGA in 1985. In Michigan, the PGA was abolished in 1982 by two referenda approved by voters and by legislation enacted by the state legislature. Discontent with rising gas costs and the existing procedure led to its abolition.

The California Commission abolished the PGA only for noncore customers. The distributor recovers the weighted average cost of the core portfolio gas from the core and the core-elect customers through annual true-ups and prudence reviews. As of May 1, 1988, the LDC recovers the cost of the gas sold to noncore customers at the weighted average cost of that gas through true-ups twice a month. The distributor, however, is at risk for these noncore purchases as there is no prudence review to cover them. The Commission made this change because it felt that the noncore customers were escaping high gas costs through fuel switching and that the costs of the distributors' commitments to purchase gas for all customers were falling increasingly on the core customers.

TABLE 2-4

COMMISSIONS WHERE PGAs HAVE BEEN ABOLISHED

California*
Michigan
Vermont

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

*Only for the noncore market.

Commission Treatment of LDC Filings

The NRRI asked a series of questions about commission procedures with respect to local distribution company PGA filings. The staff members were asked whether their commissions require LDCs to make periodic PGA filings, how frequently the LDCs must file, and what types of data the LDCs must submit to the commissions. Other questions dealt with commission hearing procedures. Staff members were asked whether their commissions hold hearings on the LDC purchased gas adjustment filings, whether hearings are held on every filing or only on certain filings, whether the commissions are required to hold hearings at any set frequency, and whether those hearings are public or closed. The authors also asked if the purchased gas contracts considered during the PGA hearings are kept confidential. The responses to these questions are discussed in two subsections below with commission filing and data requirements considered first.

Commission Requirements on Filing and Data Submission

Table 2-5 shows the commission responses to the questions on requirements to file, required frequency of filing, and types of data to include. These questions should give some indication of how active the commissions are in requiring the LDCs to report changes in gas costs and to provide the necessary data to support their positions, and thus provide some insight into how actively the commissions oversee the LDCs. Forty-seven commissions are listed in the table including six that do not require the LDC to file on any set schedule but still require the LDC to furnish data on gas purchases. For example, the Pennsylvania Commission does not require periodic filings but does require the LDC to file whenever its purchased gas costs change by 1 percent or more. Other commissions that do not require periodic filings include North Dakota, South Dakota, Washington, and Wisconsin. The Wisconsin Commission requires the LDC to file each PGA period (usually twelve months). The sixth commission not requiring regular filings is the Georgia Commission, which requires the LDC to file whenever there is a change in the purchased gas adjustment.

As can be seen from Table 2-5, the frequency with which LDCs are required to make PGA filings varies somewhat by commission. Commissions require distributors to file annually, semiannually, quarterly, and/or monthly. Some commissions (as illustrated by Georgia, Pennsylvania, and Wisconsin) require LDCs to file on the basis of other criteria rather than a set time period.

Annual filings are the most common type, required by seventeen commissions. Those commissions are Alabama, California, Colorado, Delaware, FERC, Idaho, Illinois, Kansas, Montana, Nevada, New Jersey, Oregon, Rhode Island, Utah, West Virginia, Wisconsin, and Wyoming. Monthly filings are the next most common type with thirteen commissions having this requirement. Those commissions are Arizona, Arkansas, Connecticut, the District of Columbia, Illinois, Kansas, Louisiana, Maryland, New Mexico, New York, Oklahoma, South Carolina, and Texas. Eleven commissions require semiannual filings: Delaware, Florida, Indiana, Kentucky, Maine, Massachusetts, Montana, New Hampshire, North Carolina, South Carolina, and Utah.

TABLE 2-5

FREQUENCY OF AND DATA REQUIRED FOR
LDC PURCHASED GAS ADJUSTMENT FILINGS

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
Alabama	Annually or more often if required	Demand charge, commodity cost, competitive fuel clause charges, tax factor, actual and budgeted purchase volumes, status of over/underrecovery account.
Alaska	Quarterly	Reconciliation of balancing account, monthly data on nominations of gas from each source.
Arizona	Monthly	Total gas costs for the month, sales, bank balance and forecasted gas costs for six to twelve months.
Arkansas	Monthly	Source of gas and related volumes and price.
California	Annually	Demand forecast by customer class for twelve-month period; forecasted volumes, unit prices, and costs by source; forecasted pipeline demand charges and restructuring transition costs; balancing and tracking account amortization data; revenue requirements for procurement and for transmission; allocation factors; rates and revenues by schedule.
Colorado	Annually	Commodity costs, demand costs.
Connecticut	Monthly	Official filing has summary information and PGA factor for ensuing month; staff receives details including supplier invoices, stored inventory levels, deferred balances, supplier tariffs, etc.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
Delaware	Semiannually for one LDC and annually for another LDC	Projections for the upcoming determination period for projected sales in Mcf; projected gas costs, calculation of the revised PGA rate, and status of the over/underrecovery for the prior determination period.
District of Columbia	Monthly	Commodity costs, demand-related costs, pipeline transportation charges, take-or-pay liabilities, deficiency-based and market-based pipeline gas inventory charges, storage costs, carrying charges on prepaid gas inventory balances.
FERC	Quarterly and annually	Estimated quantities of gas to be purchased, supplier rates, estimated quantity and cost adjustments for storage injections and withdrawals, estimated sales volumes; quarterly filings require limited projected cost support; annual requires extensive detail on actual costs incurred over the prior year including statements on the purchasing policies leading to annual and quarterly projections and a statement about the underlying basis for the annual purchases in the annual filing.
Florida	Semiannually	Therms purchased (firm, interruptible, other), cost of purchased gas (firm, interruptible, other), therms sold (firm, interruptible), revenue (firm, interruptible), unaccounted-for gas, revenue differential (cost of gas minus revenues, calculated for firm and interruptible), unaccounted-for gas as percentage of therms purchased (firm, interruptible), percent revenue

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
		differential (therms of unaccounted-for gas multiplied by the cost of gas adjustment cents per therm and this product divided by gas revenue; calculated for firm and interruptible), and the true-up amount.
Georgia	Any change in the PGA; periodic filings not required	Cost and quantity of gas by supplier tariff; sales in therms by customer class; franchise tax recovery factor; pipeline refunds.
Idaho	At least once per year	Documentation of customer usage (gas sales); company purchases (volumes purchased and costs incurred).
Illinois	Monthly and annually	Monthly: gas cost components, dollars and therms, gas charge, refund adjustments, purchased gas units, rates and amounts. Annually: recoverable gas costs and PGA revenue.
Indiana	Quarterly or semiannually	Pipeline and spot market supplier invoices, actual purchase and sales data, estimated purchase and sales data, most recent interstate pipeline tariff sheets on file with the FERC.
Iowa	Change in gas costs	Support for all changes in the cost of gas.
Kansas	Annually (in addition, monthly if necessary)	Cost of gas, line loss, sales.
Kentucky	Quarterly or semiannually	Nonperiodic filings: tariff sheets or correspondence showing new rate, Mcf purchases for latest available twelve month period, Mcf retail sales.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
		Periodic filings: expected gas cost based on most current supplier cost and twelve months of Mcf purchases, under or overrecovery of past gas cost with supporting documentation, amount of refund received if any.
Louisiana	Monthly	Projected purchases (for coming month) in Mcf and dollars, actual purchases from prior month (dollars), net over or underrecovery, current year annualized projected demand cost, prior year reconciliation, net annualized cost to be recovered, prior month projected and actual sales, cost of gas from each supplier, projected sales for next twelve months, prior month purchases (Mcf and dollars) by supplier.
Maine	Semiannually	Estimated total cost of gas for each month of the period during which cost of gas adjustment is proposed to be in effect; cost of gas includes total charges paid by the LDC for gas received into system supply for customer sales less cash or other discounts or supplier refunds; cost also includes associated costs such as labor and cost of handling gas prior to delivery to LDC; cost of gas also includes back-out charges, pay-out charges, take-or-pay penalties or similar charges to the extent prudently incurred; other data include any projected over- or undercollection of costs and associated interest expenses.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
Maryland	Monthly	Twelve months of billing determinants by source and applicable cost of gas by source, data on any refunds of purchased gas costs from suppliers, data relating to the current cost of acquiring gas such as commodity, demand, take-or-pay.
Massachusetts	Semiannually	Projected gas costs separated into twelve-month base and six-month supplemental projected sales volumes, base commodity costs (twelve-month base sendout volumes at the annual weighted average commodity cost of base supply), base demand charges (twelve-month demand charges associated with base sendout volumes), supplemental gas costs (total cost of the supplemental sendout), inventory finance charges (an accumulation of the projected charges calculated using the monthly average of financed inventory at the existing financing rate through a trust or other financing method), base and supplemental reconciliation adjustments, nonfirm revenue margins, supplier refunds, embedded gas costs, forecasted peak season and annual firm sales volumes.
Minnesota	Quarterly (at least)	Base gas cost (including commodity and demand costs), commodity adjustment (difference between the delivered gas cost and the base cost), demand adjustment (difference between the demand-delivered gas cost and the demand-base cost), peak shaving and manufactured gas adjustment (difference between the cost of

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
		propane or fuel consumed in the manufacture of gas during the heating season and the peak shaving or manufactured gas base cost), true-up amounts, refunds from suppliers; Monthly reports: summary of adjustments, explanation of changes between base cost and current cost, estimated previous month's and year-to-date commodity delivered gas cost by supplier, estimated volumes purchased from suppliers not regulated by the FERC, estimated costs of gas purchased from suppliers not regulated by the FERC expressed as a percentage of all commodity-delivered and demand-delivered gas costs; Annual reports: Commission-approved base cost of gas, billing adjustments, billing adjustment amounts by gas supplier that were used to bill the utility during the reporting period, total cost of fuel or gas delivered to customers including supply-related services, revenues collected from customers, supplier refunds received, refunds credited to customers.
Missouri	When a trigger figure is reached	Routine PGA changes: FERC tariffs, LDC computations, LDC tariffs; Annual reconciliation filing: all gas supply contracts, demand studies, bid sheets for gas, worksheets showing participation in the spot market, rationale for allocation factors, documentation of reliability of supply, affiliated gas sales description, imbalance calculations, gas invoices, transportation invoices, storage data, billing data, etc.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
Montana	Biannually and annually	Current gas costs, unreflected gas costs.
Nevada	Annually	Gas cost adjustment: annualized cost of gas purchased, volumes sold, volumes purchased from each pipeline and nonpipeline supplier; Gas cost balancing account adjustment: actual purchased gas cost for the month, therms billed by the utility, refunds received from gas suppliers, carrying charge.
New Hampshire	Biannually	Cost and volumes related to LDC six month purchase forecast.
New Jersey	Annually	True-up of prior annual PGA, projected twelve-month cost of gas by supplier, estimated refunds, estimated twelve months therm sales, margin sharing credits, take-or-pay liabilities.
New Mexico	Monthly	Average cost of gas, base cost of gas, difference between the average and base costs, purchase/sales ratio, amount of the gas cost factor caused by surcharge or refund, reconciliation factor, associated fees and taxes, affiliate transaction report.
New York	Monthly	Latest twelve months of purchases and storage withdrawals, purchases (less storage injections) listed by supplier and repriced at the most current rate, storage withdrawals priced at average inventory cost, transportation fees to the city gate, acquisition costs such as broker fees, purchase or sales volumes depending on use of purchase or sale method.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
North Carolina	Semiannually	Gas commodity costs, demand-related costs, pipeline transportation charges, take-or-pay liabilities, storage costs, market-based pipeline gas inventory charges.
North Dakota	Not required to file	Work papers and FERC approved tariff sheets.
Ohio	Quarterly	Historic twelve-month volumes by supplier, anticipated cost of gas, including demand costs and take-or-pay allocated to sales customers.
Oklahoma	Monthly	Information needed to verify PGA calculation.
Oregon	Annually	Actual gas costs for preceding year, known and measurable changes in costs for the upcoming year.
Pennsylvania	When LDC purchased gas costs change by 1 percent or more; not required to make periodic filings	Gas supply sources used in the last twelve months, quantity and price of gas delivered, details of take-or-pay and minimum bill provisions, details of rate designs of the purchases--including demand and commodity, quantity price, and source of gas expected to be used during each of the next twenty months--expiration date of each contract, date when each contract was most recently negotiated, details of the negotiations, and whether proceedings are pending before the FERC to modify the purchase, list of sources of gas supply considered by or offered to the LDC during the previous twelve months, but not selected by the LDC and reasons why, listing of sources and projected

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
		costs offered but not taken by the LDC for supply for the upcoming twenty months and reasons why not selected, list of FERC or other proceedings taken to relieve the LDC of contract terms adverse to ratepayers' interests, list and update of any projections of gas supply and demand previously provided to the PUC, statement of current fuel procurement practices and a plan for their improvement, a list of off-system sales by the LDC including quantities and prices involved, list of agreements to transport gas by the LDC for other utilities, pipelines, jurisdictional customers including quantities and prices involved.
Rhode Island	Annually	Projected annual firm sales, projected annual firm gas cost, projected unit (by contract) gas costs, projected gas purchase by type and quantity, projected nonfirm margins, true-up information from prior year.
South Carolina	Monthly for one LDC and semiannually for three other LDCs	Supplier invoices, calculations of gas costs.
South Dakota	Not required to make periodic filings	Computation of the PGA.
Tennessee	When rates change	Sales, purchases, current rates.
Texas	Monthly	Method and numbers used to calculate the PGA.

TABLE 2-5--Continued

Commission	Frequency of LDC Filings	Types of Data Required To Be Filed
Utah	Semiannually for one LDC; annually for another LDC	Justification for projected gas costs.
Virginia	Quarterly	Gas commodity costs, demand-related costs, pipeline transportation charges, take-or-pay liabilities, deficiency-based and market-based pipeline gas inventory charges, gas storage costs, administrative costs associated with fuel procurement, lists of commodity suppliers and firm suppliers with applicable billing determinants.
Washington	Not required to make periodic filings	Function of the magnitude of change in gas cost.
West Virginia	Annually	Projected gas costs by source of supply, listing of all supply sources under contract, listing of all supply sources investigated.
Wisconsin	Each PGA period (usually twelve months), not required to make periodic filings	D1, D2, commodity and transportation costs, the WACOG and volumes nominated, transported and sold by customer class and revenue impacts of current PGA.
Wyoming	Quarterly to annually	Projected gas costs, actual gas costs, actual recovery of gas cost in rates, over or underrecovery of gas costs.

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

Quarterly filings are required by eight commissions: Alaska, FERC, Indiana, Kentucky, Minnesota, Ohio, Virginia, and Wyoming.

Some commissions are listed in more than one of the above filing requirement categories for a variety of reasons. For example, commissions may have different filing requirements for different distributors. The Delaware and Utah commissions, which require one distributor in their states to file semiannually and another distributor to file annually, are two commissions with such a policy. The South Carolina Commission requires one distributor to file monthly and three others to file semiannually. Other commissions, such as Kansas, may have a minimal filing requirement with additional filings mandated if they are thought to be necessary. The Kansas Commission requires annual filings at least with additional monthly filings if necessary. The Minnesota Commission requires distributors to file at least quarterly. In Idaho, LDCs must file at least once a year. Some commissions may require the LDC to submit multiple types of filings during the course of the year. For example, the Montana Commission requires biannual and annual filings. In Illinois, LDCs must file monthly and annually. The FERC requires pipelines to file quarterly and provide an annual report.

As noted above, some commissions require filings on a nonperiodic basis using criteria other than a set time period. The Pennsylvania and Georgia commissions, mentioned earlier, require LDCs to file when gas costs change. Three other commissions, Iowa, Missouri, and Tennessee, also base filing frequencies on changes in gas costs. In Iowa and Tennessee, distributors must file when there is a change in their gas costs. In Missouri, a "trigger" figure is established and the LDC must file when that figure is reached.

In Kentucky, LDCs can choose to file either periodic or nonperiodic PGAs. Those choosing the periodic option file on the basis of a schedule specified in the cost of gas adjustment provisions. As shown in Table 2-5, filings would be either quarterly or semiannually. In the past, the major LDCs were more likely to file periodic PGAs. Distributors choosing the nonperiodic option would file when their supplier rate changes.

Table 2-5 also shows the types of data that distributors must submit to commissions in their PGA filings. The basic data required include commodity costs (purchased gas costs), demand costs, projected costs and purchases for the upcoming PGA period, actual costs for the past PGA period, revenues received from each customer class, and quantities of gas purchased and sold. The actual calculations and supporting documentation might also be submitted. Other types of data also required include pipeline transportation charges, take-or-pay liabilities, gas inventory charges, reconciliation of balancing account (over and underrecovery of costs), refunds received from pipelines, gas supplier invoices (pipeline and spot market purchases), storage costs, and gas supply contracts.

Different commissions require different combinations of the above types of data and may also vary their requirements by LDC (as does the Arkansas Commission). Requirements may also vary by the occasion or frequency of the filing with certain data necessary in the initial filing and different data in a subsequent filing. For example, the Illinois Commission requires distributors to submit data monthly and annually. In the monthly filing, the distributor must document gas cost components, dollars and therms, gas charges, refund adjustments, and purchased gas units, rates and volumes. In the annual filing, the distributor must document recoverable gas costs and PGA revenue. The FERC requires quarterly and annual filings. In the quarterly filings, the pipeline must submit projected cost data while extensive data on actual costs incurred must be included in the annual filing.

The commissions also vary in the amount of data they require the LDC to submit in their PGA filings. Some commissions, such as Idaho, require the basic data of gas sales, volumes purchased, and costs incurred; other commissions require more data. In Pennsylvania, distributors must submit information such as descriptions of supply sources, quantities and prices of gas delivered to the distributors, take-or-pay and minimum bill provisions, sources to be used in the next twenty months, expiration date of each contract, the date when each contract was most recently negotiated and the details of the negotiations, whether proceedings are pending before the FERC to modify purchases, a list of sources of supply considered by or offered to the LDC during the previous twelve months but not selected and the reasons why, a list of sources and projected costs offered but not taken by the distributor for supply for the upcoming twenty months and the reasons why not selected, a list of proceedings before the FERC or other agencies undertaken by the distributor to relieve the LDC of contract terms adverse to the ratepayers, and a list of off-system sales by the LDC.

Commission Hearing Procedures

The absence of hearings does not necessarily mean that a commission is not performing effective oversight of LDC gas purchasing. Hearings, however, can provide an important opportunity for the commission to review what the distributor is doing and can force the utility to defend its actions. Some commissions instead may perform oversight in rate case hearings (as the Arizona Commission responded) or audits (as the District of Columbia Commission responded). The first question that the authors asked was whether the commission holds hearings on an LDC's PGA filing and whether hearings are held on every filing or only on certain filings. Table 2-6 shows the commissions that hold hearings on every PGA filing and those that hold hearings only on certain filings.

As the table shows, most commissions do hold hearings on distributors' PGA filings. Thirteen commissions hold hearings on every filing while seventeen take such action only on certain filings. There is no overlap between these two categories so that thirty, or almost two-thirds, of the forty-eight commissions with purchased gas adjustment clauses hold some hearings on the associated filings. Some comments on specific commissions follow.

A few of the commissions that hold hearings on every filing provided some additional explanation and these are considered first. At the Nevada Commission, hearings are requested by the staff. Recently all purchased gas adjustments have been settled by stipulation. In Ohio, every filing is audited. The review is after the fact and costs can be challenged in the PGA hearings. In Oklahoma, all filings are verified in a general fuel audit with any problems resolved in a general fuel hearing.

Commissions holding hearings only on certain filings generally take such action to consider disputed, unusual or new items in the PGA. Examples of such disputed

TABLE 2-6

FREQUENCY OF COMMISSION HEARINGS
ON LDC PGA FILINGS

Commission Holds Hearings On Every PGA Filing	Commission Holds Hearings Only On Certain PGA Filings
California	Alaska
Colorado	Connecticut
Delaware	FERC
Florida	Idaho
Indiana	Illinois
Maryland	Iowa
Nevada	Kentucky
New Hampshire	Maine
New Jersey	Missouri
Ohio	Montana
Oklahoma	New Mexico
Rhode Island	North Carolina
Utah	Oregon
	Pennsylvania
	South Carolina
	West Virginia
	Wyoming
(N=13)	(N=17)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

or new items, as given by respondents, include major price increases, new gas purchases, or take-or-pay charges. Hearings may also be held on the filings of the state's larger distributors. Comments on specific commissions follow.

In Alaska, nonroutine filings, which might include items such as new gas contracts or legal settlements, would be subject to a hearing. The Kentucky Commission uses hearings to consider special issues or extraordinary circumstances. At the FERC, hearings are held usually to consider purchasing practices or prudence issues. In Idaho, the Commission would hold a hearing if a dispute arose over a filing. There, a hearing is thought to be the best way to take evidence from the parties. The Iowa Board and the Missouri and Wyoming Commissions also hold hearings on contested filings.

In Maine, hearings are used to consider the winter PGA filing or controversial and unusual topics such as take-or-pay charges. The Illinois Commission holds hearings on annual reconciliation filings. The Montana Commission holds hearings when cost increases are involved or when a party makes a request for a hearing. In North Carolina, hearings could be used to work out differences between the public staff and the distributor that cannot be otherwise resolved. The Oregon Commission may hold hearings on general rate case gas costs. The West Virginia Commission holds hearings on the PGA filings of its largest distributors.

The New Mexico Commission usually will not hold hearings on a distributor's PGA filing prior to its effective date. The Commission may, however, suspend a filing and hold a hearing under the terms of Commission Rule 640.[5] The Commission may take such action on its own initiative or after receiving a consumer complaint. Issues that might be considered during a hearing include any unusual substantial increase (15 percent) in the rates charged by any of the LDC's major gas suppliers (affiliated or nonaffiliated), major new contractual arrangements for purchases of gas that differ by 10 percent or more from existing arrangements with the same producer, disputes over the interpretation of contracts or laws affecting the pricing of at least 3 percent of the distributor's gas supply, new or amended

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[5] NMPSC Rule 640: Purchased Gas Adjustment Clauses for Gas Utilities; 640.7: Purchased Gas Adjustment Clause Hearings (1988).

contractual arrangements for services related to the supply of gas (processing, gathering, or transportation), and/or any other matter the Commission decides should be considered. In addition, the Commission is required to hold a hearing on any filing in which the distributor requests a 10 percent increase in the cost of gas over the existing PGA.

The Pennsylvania Commission holds hearings on the PGA filings of larger Group One utilities (those with in-state revenues greater than $40 million). The LDC must file with the Commission when there is a change of 1 percent or more in its purchased gas costs. After the filing is made, the Pennsylvania Commission may then begin a formal investigation into the appropriate rate level.

Table 2-7 lists the fourteen commissions that responded they are required to hold PGA hearings at a set frequency. Annual and semiannual hearings are the most common with seven and six commissions, respectively, (including Delaware which responded affirmatively to both) noting these frequencies. Other, less common, frequencies listed in the table include monthly, quarterly, biennially, and when filings are made.

In California, annual hearings are required. Six-month filings are permitted if core revenues would change by more than 4 percent in the middle of the year. The Connecticut DPUC holds administrative proceedings monthly and then quarterly hearings. The Indiana Commission holds a summary hearing on every cost of gas adjustment filing. The Pennsylvania Commission holds annual hearings to consider the reconciliation of past costs and cost recovery. In Ohio, the Commission is not required to hold hearings with any set frequency. Commission regulations specify periodic hearings, which is interpreted to mean annual for the large LDCs and biennially for the small LDCs. The South Carolina Commission also is not required to hold hearings with any set frequency, however there are such proceedings annually for three distributors and semiannually for one.

As Table 2-8 shows, most commissions that conduct PGA hearings open them to the public. The table lists the thirty-five commissions responding that their PGA hearings are public. None responded that their PGA hearings are closed. This list contains five more commissions than Table 2-6 which listed those commissions holding

TABLE 2-7

COMMISSIONS REQUIRED TO HOLD PGA HEARINGS
AT A SET FREQUENCY

Commission	Frequency With Which Hearings Must Be Held
California	Annually (if necessary semiannually)
Colorado	Annually
Connecticut	Monthly and quarterly
Delaware	Annually and semiannually
Florida	Semiannually
Illinois	Annually
Indiana	When filings made
Maryland	Semiannually
New Hampshire	Semiannually
New Jersey	Annually
New Mexico	Every two years
Oklahoma	Semiannually
Pennsylvania	Annually
Rhode Island	Annually

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

TABLE 2-8

COMMISSIONS WITH PUBLIC PGA HEARINGS

Alaska	Montana
Arizona	Nevada
California	New Hampshire
Colorado	New Jersey
Connecticut	New Mexico
Delaware	North Carolina
FERC	North Dakota
Florida	Ohio
Idaho	Oklahoma
Illinois	Oregon
Indiana	Pennsylvania
Iowa	Rhode Island
Kansas	South Carolina
Kentucky	Utah
Maine	Washington
Maryland	West Virginia
Minnesota	Wyoming
Missouri	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

hearings on all or on certain filings. Staff members from five commissions (Arizona, Kansas, Minnesota, North Dakota, and Washington) that had responded negatively to the first question of whether their commissions hold PGA hearings also answered that hearings concerning PGA at those commissions are public.

Much of the apparent discrepancy between the lists in the two tables can be explained, however. The Arizona Commission does not hold separate PGA hearings. Purchased gas adjustments are considered during rate case proceedings, which are public. The Minnesota Commission does not hold PGA hearings except on contested filings. Typically, hearings are not held in those instances either, but they would be public if held. The North Dakota Commission's procedure is similar to Minnesota's.

Hearings are not held routinely, but if a matter of contention arose, it could lead to a hearing which would be a public proceeding. The Washington Commission procedure is similar. The PGA is generally not contested and hearings are not held when the LDC files. If Commission staff felt that something was not appropriate about the filing, the Commission could suspend it and hold hearings. The Kansas Commission also does not hold hearings specifically for purchased gas adjustments. PGA matters may arise in rate case or other proceedings. In addition, if there was a dispute over a purchased gas adjustment a hearing could be held. All hearings at the Commission are open to the public.

At the FERC, hearings are public as shown in Table 2-8. However public participation could be limited in cases involving discussion of confidential material. This comment leads into the next issue to be considered: the confidentiality of purchased gas contracts considered during hearings. As Table 2-9 shows, a significant number of commissions--twenty-three--are willing to close off portions of their proceedings to the public (that is, certain documents). This number is somewhat smaller, however, than the thirty-five commissions listed in Table 2-8 as having public proceedings. At eight of the twenty-three commissions in Table 2-9, confidentiality is not automatic but is granted only upon request of a party to the proceeding. All of the commissions in Table 2-9 except the District of Columbia are also in Table 2-8. This indicates that the commissions are trying to strike some balance between the ratepaying public's interest in information and access to the regulatory process and the utility's interest in protecting proprietary information (particularly where confidentiality is necessary for the efficient operation of the utility).

Comments on specific commissions are provided here. At the District of Columbia Commission, gas contracts are given confidential treatment when used in any formal proceeding. At the FERC, contracts are usually kept confidential. At the Wyoming Commission, parts of the gas contracts such as the price and supplier may be given protection. Under state law, the Washington Commission provides confidential protection for gas contracts, however, if a party seeks access to those agreements, the Commission will honor that request. The LDC must then seek a court ruling ordering the Commission not to make the contracts public. In Illinois,

TABLE 2-9

COMMISSIONS THAT GIVE CONFIDENTIAL TREATMENT TO PURCHASED GAS CONTRACTS

California	Minnesota
Colorado	Missouri
Connecticut	Nevada
Delaware	New Jersey
District of Columbia	New Mexico
FERC	Ohio
Illinois	Oklahoma
Iowa	Oregon
Kansas	Pennsylvania
Kentucky	South Carolina
Maryland	Washington
	Wyoming

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

Iowa, Kentucky, Minnesota, Missouri, Nevada, Ohio, and Pennsylvania, confidentiality is provided if requested by the distributor or any other interested party. The Ohio Commission must issue a protective order to insure confidentiality. At the Pennsylvania Commission, the request for confidential treatment may be submitted along with the data. An administrative law judge rules upon the request within fifteen days after being assigned to the case. Until that ruling is issued, the information is not required to be shared with other parties. The Kentucky Commission may give confidential protection to purchased gas contracts if a request is made which the Commission approves.

Other commissions are considering the question of confidentiality or have not yet had to address it. Still other commissions do not grant confidentiality. The

Arizona Commission has not resolved the issue one way or the other, although the matter has been raised in discussions of the PGA. The issue has not arisen at all in Idaho. The Alaska, Indiana, Maine, Montana, New Hampshire, Rhode Island, Utah, and West Virginia Commissions give no confidential protection to purchased gas contracts.

PGA Treatment of Costs

The authors included questions in the survey dealing with the costs allowed in the purchased gas adjustment, and PGA treatment of cost increases and decreases. The questions of what costs are recovered and how increases and decreases in costs are treated are at the core of the interest and debate over the role and function of purchased gas adjustment and electric fuel adjustment clauses. Whether certain costs are legitimate and whether ratepayers benefit or are harmed by operation of these mechanisms are two of the major regulatory issues. In asking what types of costs are allowed, the NRRI listed several categories on the questionnaire, including gas commodity costs, demand-related costs, pipeline transportation charges, gas take-or-pay liabilities, deficiency-based pipeline gas inventory charges, market-based pipeline gas inventory charges, gas storage costs, administrative costs associated with fuel procurement, and other costs. The staff member responses with respect to the major types of costs (excluding other costs) are shown in Table 2-10.

As might be expected, the basic types of gas costs, including commodity costs, demand costs, and pipeline transportation charges, are allowed into the PGA by practically all commissions. These costs (except perhaps for pipeline transportation) are almost universal for LDC gas purchasing and constitute a minimum that a PGA could include. Take-or-pay liabilities and storage costs are allowed by fewer commissions, albeit still a majority. The smaller number of commissions allowing storage costs might be due to jurisdictional LDCs in some states having no storage gas or facilities. For take or pay, some LDCs might have no liabilities or limited liabilities to pass on. Some state commissions have also been resisting the pass-through of these costs, particularly from the pipeline supplier. However, the large

TABLE 2-10

COMMISSIONS ALLOWING VARIOUS MAJOR TYPES OF COSTS INTO PGA CLAUSES

Type of Cost	Commissions Allowing This Cost in the PGA
Gas Commodity Costs	Alabama, Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Virginia, Washington, West Virginia, Wisconsin, Wyoming (N=47)
Demand-Related Costs	Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Virginia, Washington, West Virginia, Wisconsin, Wyoming (N=45)

TABLE 2-10--Continued

Type of Cost	Commissions Allowing This Cost in the PGA
Pipeline Transportation Charges	Alabama, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Virginia, Washington, West Virginia, Wisconsin, Wyoming (N=44)
Gas Take-or-Pay Liabilities	Alabama, Arizona, California, Delaware, District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Montana, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Virginia, Washington, West Virginia, Wisconsin, Wyoming (N=36)
Deficiency-Based Pipeline Gas Inventory Charges	Alabama, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Maryland, Massachusetts, Mississippi, Missouri, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Virginia, Washington, Wisconsin, Wyoming (N=27)

TABLE 2-10--Continued

Type of Cost	Commissions Allowing This Cost in the PGA
Market-Based Pipeline Gas Inventory Charges	Alabama, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Maryland, Massachusetts, Mississippi, Missouri, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Virginia, Wyoming (N=27)
Gas Storage Costs	Alabama, California, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Montana, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Virginia, Washington, Wisconsin, Wyoming (N=35)
Administrative Costs Associated with Fuel Procurement	Arizona, California, Florida, Georgia, South Dakota, Virginia, Wyoming (N=7)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

number of commissions shown in the table indicates that for the most part these costs are being passed on.

Gas inventory charges (GIC) are permitted by slightly more than half the commissions. This might be due in part to the fact that the survey was conducted when the policy regarding such charges still was being developed. As these charges become more accepted, more commissions undoubtedly will allow GICs into the PGA. Few commissions allow administrative costs associated with fuel procurement into the PGA. The rejection of these costs as legitimately recovered through the PGA is widespread among the commissions. As distributors engage in more direct and spot purchasing to find the least-, best-cost gas supply mix, more commissions may allow the administrative expenses into the PGA. In addition, regulators may be allowing these costs to be recovered through rate cases.

Some commissions provided additional comments on these major costs. The Arizona Commission includes some but not all take-or-pay liabilities in the PGA. Recovery of administrative costs related to fuel procurement is also not automatic. The California Commission excludes only general rate case base costs from the PGA. The FERC allows demand-related costs on an as-billed basis from pipeline suppliers and pipeline transportation charges only by specific waiver or if such charges are part of the gas purchase cost. The FERC allows gas inventory charges if the pipeline does not have its own GIC, and with respect to storage allows only the cost of the gas itself (with some exceptions).

In New Hampshire, gas commodity costs include pipeline charges plus liquid natural gas and propane. Storage costs include commodity costs and demand costs. The Ohio Commission allocates take-or-pay liabilities between sales and transportation customers. At the Washington Commission, the inclusion of deficiency-based GICs was still being decided at the time of the survey. The Delaware Commission was considering the inclusion of take-or-pay costs. In Indiana, only one LDC had filed to pass-through gas inventory charges and no party had opposed recovery of that cost. At the Wyoming Commission any of the costs listed on the questionnaire could be included in the PGA if they were included in FERC-regulated pipeline rates.

The fourteen commissions allowing other types of costs into the PGA are listed in Table 2-11. As can be seen, an interesting variety of costs is passed through including royalty payments; fees paid to counsel; supplemental gas; taxes; storage costs; LDC gas production costs; inventory financing costs; propane and liquid natural gas; manufactured gas; gathering; Btu adjustments; pipeline surcharges; and interest on the deferred balance.

As shown in Tables 2-10 and 2-11, storage costs are a prominent component of the costs in the PGA. Most commissions allow storage-related (typically withdrawn gas) costs to be recovered through purchased gas adjustment procedures. While many of the regulatory issues relating to the uses of gas storage have been dealt with at length in another NRRI study,[6] the authors felt that some additional information on LDC storage arrangements would be useful for understanding an important cost. Thus, the NRRI asked staff members whether LDCs in their states own or lease (or neither own nor lease) storage. The responses are summarized in Table 2-12.[7]

The table shows the widespread use of storage by local distribution companies and helps explain why a large number of commissions allow these costs into the PGA. Twenty-nine commissions (twenty-seven states, the District of Columbia, and the FERC) are listed in the LDC-ownership-of-storage column (although the FERC answer applies to interstate pipelines). Twenty-five commissions are listed in the LDC-leasing-of-storage column. Nine commissions, Delaware, Iowa, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island, South Carolina, and Virginia, listed in the leasing column are not listed in the ownership column. Thus, thirty-eight commissions oversee local distributors that either own or lease gas storage. However, recalling the list in Table 2-10 of thirty-five commissions (thirty-three states, the District of Columbia, and the FERC) that allowed recovery of storage costs in the

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[6] Daniel J. Duann et al., *Gas Storage: Strategy, Regulation, and Some Competitive Implications* (Columbus, OH: The National Regulatory Research Institute, 1990).

[7] Respondents also provided a large amount of data and interested readers are referred to question 3 in Appendix A of the separate volume report, which is available upon request from the NRRI Publications Office.

TABLE 2-11

COMMISSIONS ALLOWING OTHER TYPES OF
COSTS INTO PGA CLAUSES

Commission	Other Costs Allowed Into the PGA
Alabama	Carrying charges for prepayment of gas purchased; competitive fuel clause adjustments
Alaska	Recovery of retroactive excess royalty payments
Connecticut	Refunds/surcharges; interest on deferred balance
District of Columbia	Carrying charges on prepaid gas inventory balances
Georgia	Legal fees paid to Washington, DC law firm to handle FERC business
Illinois	Manufactured gas, supplemental gas, storage gas: withdrawals net of injections
Maine	Supplemental gas costs, LNG truck transportation costs, pipeline surcharges (FERC approved), interest-financing fuel, under/overrecovery of costs
Massachusetts	Storage service charges, inventory trust charges, interest on deferred balances, company-use gas, purchased gas, cash working-capital
Mississippi	Btu adjustments, municipal franchise tax, tax adjustments resulting from any increase or decrease in LDC cost of gas
New Hampshire	Inventory financing charges, interruptible gas sales profits (negative cost), prior period over/undercollection and interest, refunds, FERC surcharges

TABLE 2-11--Continued

Commission	Other Costs Allowed Into the PGA
Ohio	Utility-owned production costs, propane used for peak-shaving or base load subject to the cost of replacement of the propane versus the alternative gas price
Oklahoma	Gas acquisition costs including refunds and corrections
Oregon	Revenue-sensitive franchise fees, interest on gas cost changes
Utah	Gathering

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

TABLE 2-12

COMMISSION RESPONSES ON LDC OWNERSHIP OR LEASING OF STORAGE*

LDC Owns Gas Storage Capacity	LDC Leases Gas Storage Capacity	LDC Neither Owns Nor Leases Gas Storage
Arkansas	Connecticut	Alabama
California*	Delaware	Alaska
Colorado	District of Columbia	Arizona
Connecticut	Idaho	California*
District of Columbia	Illinois	Florida
FERC**	Indiana	Indiana
Georgia	Iowa	Louisiana
Idaho	Kansas	Minnesota
Illinois	Maine	Missouri
Indiana	Massachusetts	Montana
Kansas	Minnesota	Nevada
Kentucky	Mississippi	New Mexico
Maryland	Missouri	New York
Michigan	New Hampshire	North Dakota
Minnesota	New Jersey	Ohio
Mississippi	New York	South Dakota
Missouri	North Carolina	Utah
New Mexico	Ohio	Vermont
New York	Oregon	Virginia
North Carolina	Pennsylvania	West Virginia
Ohio	Rhode Island	Wyoming
Oklahoma	South Carolina	
Oregon	Tennessee	
Pennsylvania	Virginia	
Tennessee	Washington	
Texas		
Vermont		
Washington		
Wyoming		
(N=29)	(N=25)	(N=21)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

* Some commissions may be listed in more than one column because LDCs under their jurisdiction may own and/or lease storage and/or neither own nor lease storage.
**Answer applies to interstate pipelines.

PGA, one can conclude that recouping storage expenses through the purchased gas adjustment may be common but not always automatic.

Having considered the types of costs allowed in the PGA, the authors also inquired about changes in those costs; that is increases and decreases. The NRRI asked a two-part question: first, does the commission's PGA procedure treat cost decreases differently than cost increases, and second, are purchased gas cost decreases passed through to customers as quickly as cost increases? Staff members were asked to explain any differences in their commissions' treatment of cost increases and decreases, especially noting any differences among customer classes.

The responding commissions were nearly unanimous in saying, first, that cost decreases are not treated any differently than cost increases, and, second, that cost decreases are passed through to customers as quickly as cost increases. Only three commissions answered differently: Kentucky, New Hampshire, and North Carolina. Other staff respondents provided some additional explanations for their commissions' positions. All of these comments are considered below, beginning with the above three.

The Kentucky Commission responded affirmatively to both questions: cost decreases are treated differently and cost decreases are passed through as quickly. The explanation lies in the system of periodic and nonperiodic filings, described above. With respect to the current question, the effective date of cost decreases in nonperiodic PGA filings is dependent on the effective date of the change in the supplier rate. Cost increases require a minimum of twenty days' notice before taking effect.

In New Hampshire, cost decreases are not treated any differently though they may not be passed through as quickly as cost increases. The difference lies in the possible existence of a trigger mechanism. If the actual costs exceed the forecasted costs by the specified percentage of the trigger, the LDC can file for a midterm correction. If the actual costs fall short of the forecasted costs by the specified percentage, the Commission staff could file for the correction. In North Carolina, while cost decreases are treated no differently than cost increases, the decreases are placed in a deferred account with interest added. This amount is then included as a decrease in the next PGA filing.

Other commissions commenting on their procedures included the FERC. The FERC treats all customer classes similarly. Decreases can be passed through more quickly than initial rate increases because the pipeline can file for the decreases with a twenty-four-hour notice. An increase retroactive to the initial pre-decrease level can also take effect after a twenty-four-hour notice. In Idaho, cost decreases are sometimes passed through more quickly than the thirty days required for cost increases. The Montana Commission varies its procedure somewhat for cost decreases, issuing a Notice of Opportunity for Public Hearing instead of requiring an actual hearing.

In Nevada, customers using more than 50 Mcf per day are billed immediately for cost changes. Other customers pay an Account 191 surcharge. In New Jersey, there is a true-up at the end of the PGA period. Decreases and increases are taken into account in the next filing and interest is accrued on any overrecovery. In Virginia, there is no difference between the treatment of cost increases and cost decreases in the PGA although supplier refunds may be handled differently for different customer classes. Large industrial customers receive a refund check. For other customers, the refund is reflected in the PGA rate charged.

Accounting Procedures, True-Up, and Treatment of Overcharges

The above discussion deals with how costs and changes in costs are treated in the PGA process. In the survey, the NRRI also included questions about accounting and true-up procedures and the treatment of overcharges in the PGA. While costs are at the heart of the PGA process, the authors also felt it was important to learn about some of the factors leading up to the PGA filings, including the question about storage discussed above and the question about accounting discussed in this section. It is also important to know about other aspects of the process, particularly how overcharges, which might have a potentially major impact on ratepayers, are handled. True-up, monitoring, refund, and offset procedures thus are considered.

Required Accounting Practices

Table 2-13 shows thirty-two commissions that require distributors to use particular accounting practices. As might be expected, many of the commissions listed require the use of either the FERC Uniform System of Accounts or the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts.

Respondents mentioning the FERC Uniform System of Accounts include California, Delaware, the District of Columbia, the FERC, Indiana, Missouri, Ohio, and South Dakota. Respondents mentioning the NARUC Uniform System of Accounts include Alabama, Georgia, Indiana, Maine, Montana, New Mexico, and Texas. Respondents from the Florida, New York, South Carolina, Wisconsin, and Wyoming Commissions mentioned the Uniform System of Accounts without specifying which system.

The California Commission uses the FERC system with modification, creating subaccounts for core and noncore customers as part of restructuring the state's gas industry. For example, the core purchased gas account is designed to balance the recorded cost of gas bought by the distributor for the core procurement market with the revenue received from the sale of that gas. This is a balancing account defined as an account in which expenses are compared with revenues from rates designed to recover those costs, or in which forecasted revenues are compared with recorded revenues. Any over or undercollection plus interest calculated in a prescribed manner is recorded on the distributor's financial statement as an asset or liability which is then paid back to or collected from the ratepayers. Balances in these accounts are amortized in rates.

The noncore purchased gas account is designed to track the recorded cost of gas purchased by the LDC for the noncore procurement market and revenue received from the sale of that gas. It is a memorandum account, specially created by the California Commission to record certain costs. The noncore account functions in a similar fashion to the balancing account although no interest is accumulated and the

TABLE 2-13

COMMISSIONS THAT REQUIRE THE LDC TO USE PARTICULAR ACCOUNTING PRACTICES

Alabama	Montana
Alaska	Nevada
California	New Hampshire
Connecticut	New Jersey
Delaware	New Mexico
District of Columbia	New York
FERC	Ohio
Florida	South Carolina
Georgia	South Dakota
Illinois	Texas
Indiana	Utah
Maine	Vermont
Massachusetts	Virginia
Minnesota	Washington
Mississippi	Wisconsin
Missouri	Wyoming

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

distributor's stockholders are at risk for any resulting over or undercollection. This account is not recorded on the LDC's financial statement.

Other accounts authorized by the California Commission in restructuring the gas industry include the core fixed cost account, a balancing account to reconcile the recorded pipeline demand charges, and transition costs and any forecasted margin costs allocated to the core market with all nongas revenue received from that market. The noncore fixed cost account is a memorandum account to track recorded pipeline demand charges and forecasted margin costs that have been allocated to the noncore market and nongas revenues received from the noncore market. The noncore transition cost account is a balancing account intended to reconcile certain costs related to the market restructuring and allocated to the noncore market with transition-related revenue received from noncore customers.

The Maine Commission's regulations specify that the LDC is to follow the NARUC Uniform System.[8] The distributor may also utilize subsidiary or other records or accounts so long as they do not interfere with the required NARUC accounting procedures. The distributor's accounts are to be audited and the report filed with the Commission. The Minnesota Commission requires LDCs to follow the Minnesota uniform system of accounts. This system incorporates many of the federal regulations.

The Mississippi Commission's regulations[9] require every utility to establish a system of accounts in accord with Commission orders. Utilities regulated by a federal agency that prescribes its own accounting system may instead follow the federally mandated system. The Commission, however, reserves the right to prescribe additional forms, books, records, or accounts as long as they do not conflict with those required by the federal agency.

The Massachusetts Department separates costs on the basis of seasonality. The base Gas Adjustment Factor (GAF) is applied during the off-peak summer season and the base and supplemental factors are applied during the peak winter season. Distributors are required to separate their costs and accounts on this seasonal base and supplemental basis. The Illinois Commission specifies any of three methods of accounting for gas costs and revenues: as billed, deferred cost, and unbilled revenue. Besides using the FERC system, the District of Columbia Commission also prescribes the Actual Cost Adjustment (ACA) system. The Utah Commission specifies Account 191.

Various commissions require the LDCs to establish balancing accounts to record over and undercollections, including California (mentioned above). In Alaska,

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[8] See 65-407 Code of Maine Regulations, Chapter 410 (1988).

[9] Rule 3: Accounts, Records, and Reports.

the LDC estimates its gas costs on January 1 each year and maintains the balancing account. The Connecticut Department tracks over and undercollections through deferred accounting. The New Jersey Board and the Virginia Commission also use deferred accounting. The Washington Commission uses deferred accounting but also employs the previous rate case rate base determination for the distributor's gas inventory.

The Nevada Commission requires its LDCs to establish a balancing account. Each month the utility must enter a debit or credit equal to the difference between (a) the purchased gas cost for the month and (b) the product obtained by multiplying the current tariff rate by the therms billed under the applicable rate schedule. The utility must also enter a debit or credit obtained by multiplying the therms billed during the month under the applicable tariff rates by the gas cost balancing account adjustment contained in the rates charged during the month. The adjustment per unit of gas sold is found by dividing the balance in the account at the end of the month three months prior to the revision date of the tariff by the number of therms sold under the applicable rate schedules of the tariff for the twelve months ending three months prior to the revision date. Any refunds received by the distributor from its gas suppliers that may apply to sales made under the rate schedules of the tariff are to be credited to the gas cost balancing account.

The New Hampshire Commission, like other commissions already mentioned, requires distributors to track a variety of costs including prior PGA-period over and undercollections, refunds from gas suppliers, interest, interruptible sales margin, total anticipated cost for the upcoming PGA period, projected sales, and unit cost of gas sold. These data are the figures used in the actual calculations of the cost of gas adjustment.

In addition to the commissions that require distributors to use particular accounting practices, two of the commissions (Arizona and Pennsylvania) that do not have such a requirement offered comments. The Arizona Commission requires certain accounting procedures only when necessary to deal with special issues that have arisen during rate proceedings. The Pennsylvania Code of Statutes provides the framework for voluntary filings for rate increases by utilities, listing a variety of accounts by specific number and name. Utilities are required to provide the type of information that the Code specifies and thus maintain their accounts within the Code's framework. However, the Commission requires no formal accounting procedures within the PGA.

True-Up Procedures

It is also worthwhile to know whether the commissions' PGA procedures include a true-up procedure. The true-up is an important part of the PGA process because at this stage any over and/or underrecoveries of costs that the LDC has made must be reconciled. Balancing accounts, discussed above, are important in the true-up as they provide the information (over and underrecovery of costs) on which the actual reconciliation of expenses with revenues is based. Table 2-14 shows the commissions that have a true-up procedure.

As can be seen from Table 2-14, the true-up is frequently included by commissions in the PGA: forty-six are listed. The basic procedure consists of tracking costs and revenues for the current PGA period. At the end of the period, the reconciliation or true-up is done and the over or underrecovery is factored into the next period's PGA. For example, in one Florida case the LDC calculated an underrecovery of purchased gas costs (the true-up amount) totalling $576,703 including interest from April 1 through September 30, 1989.[10] The distributor estimated that its sales for April 1 through September 30, 1990 would be 224.3 million therms and it wanted to apply a true-up factor of $0.00257 to each therm sold during that period to recover the costs from the previous year.

Interesting variations on the basic pattern of true-up procedures occur in Oregon and Wyoming. Both constitute attempts by the commissions to provide incentives to the LDC. The Oregon Commission allows only 80 percent of costs and

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[10] In re: Purchased Gas Adjustment (PGA) True-up; Petition of Peoples Gas System, Inc., for Approval of PGA True-Up Factor for Application to Bills Rendered During the Period April 1 through September 30, 1990, Docket No. 900003-GU, Submitted for filing January 5, 1990.

TABLE 2-14

COMMISSIONS WITH
A TRUE-UP PROCEDURE
IN THE PGA

Alabama	Missouri
Alaska	Montana
Arkansas	New Hampshire
California	New Jersey
Colorado	New Mexico
Connecticut	New York
Delaware	North Carolina
District of Columbia	North Dakota
FERC	Ohio
Florida	Oklahoma
Georgia	Oregon
Idaho	Pennsylvania
Illinois	Rhode Island
Indiana	South Carolina
Iowa	South Dakota
Kansas	Tennessee
Kentucky	Texas
Louisiana	Utah
Maine	Virginia
Maryland	Washington
Massachusetts	West Virginia
Minnesota	Wisconsin
Mississippi	Wyoming

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

revenues to be placed into the balancing account with stockholders responsible for the other 20 percent, which is theirs either to lose or gain. The Wyoming Commission requires the LDC to pay interest to ratepayers if it overcollects its costs. Comments on the policies and procedures of individual commissions follow.

In Alabama, the LDC files a new tariff to balance over and underrecoveries. The LDC adjusts the PGA during the year to reflect changes in the cost of gas and to keep adjustments at the end of the year to a minimum. The Alaska Commission true-up is self-correcting. In Arkansas, over and undercollections from one period are reflected in the PGA in the next. At the California Commission, most PGA accounts are balancing accounts but there are also a few of the memorandum accounts that were mentioned previously in the discussion of core and noncore accounting procedures. The memorandum accounts, however, are not used in the true-up as balances are not carried over from one PGA period to the next and the LDC may earn a profit or suffer losses. These accounts are part of the monitoring mechanism and are intended to prevent subsidization of noncore customers by core customers.

The Connecticut Department uses a deferred factor for a twelve-month period with a reconciliation done in August. This true-up covers the next twelve months. In Delaware, PGA rates cover one year. The under or overrecovery is then calculated and factored into the next period's PGA. The District of Columbia Commission performs the true-up in August covering the previous twelve months. The under or overrecovery is then passed on to ratepayers in an actual cost adjustment for twelve months. At the FERC, actual incurred gas costs are compared to projected costs that were included in rates. The differences are covered in deferred accounting and the balance is either surcharged or returned at the end of the year. In Idaho, the LDC maintains records of the exact amounts passed through to ratepayers. Over or undercharges are balanced in the next period.

The true-up calculation in Florida for each month of the PGA period begins by summing total gas revenues for the month with the collection of the prior period true-up to produce the total gas revenue applicable to the current period. From this amount the total gas costs for the month, interest, and the negative of the prior period true-up are subtracted. The true-up amount with interest at the beginning of the month is added. The result of this calculation is the total net true-up. In Illinois, the annual gas cost is reconciled with revenue. Any over or underrecovery is refunded to or collected from ratepayers as a PGA adjustment for twelve months beginning in April of the following year. The Kansas Commission procedure also spreads any under or overrecoveries over the following year. In Massachusetts, the annual reconciliation begins in November while in Iowa it begins on September 1.

In Indiana, distributors filing quarterly gas cost adjustments calculate a three-month reconciliation of actual and estimated gas costs resulting in a gas cost variance. The variance is allocated to the current and three following quarters on the basis of estimated sales volumes. The variance in the current gas cost adjustment is thus a composite of variances from the three previous adjustments and the current adjustment. This variance is factored in with the estimated gas costs along with any applicable refunds. For distributors filing gas cost adjustments semiannually any variance from the reconciliation months is placed into the current adjustment. In Kentucky, there are two tracking or true-up mechanisms for distributors making periodic PGA filings. One of the true-up procedures reconciles the expected with the actual gas costs from previous periods. The other procedure is a "catch-all" to handle any remaining over or underrecoveries.

In Maine a reconciliation is conducted for each gas adjustment period (winter and summer). Winter over- or underrecoveries are balanced out in the following winter period while summer over or underrecoveries are reconciled in the next summer adjustment period. The New Hampshire Commission uses the same winter-to-winter and summer-to-summer procedure. The Maryland Commission procedure specifies the annual calculation of an actual cost adjustment balancing costs and recoveries. In Mississippi, the true-up mechanism varies from distributor to distributor and it is specified in the individual gas adjustments approved by the Commission. In Missouri, a reconciliation audit of the LDC's deferred accounts is performed annually to verify the accuracy of payments and collections and the prudence of purchases. The Montana Commission policy allows account balances to be included in gas cost adjustment calculations. In New Jersey, LDCs file PGAs for the upcoming twelve months, including actual compared with estimated data for the previous period.

Minnesota Commission regulations specify a true-up procedure.[11] The true-up amount is to be the difference between the gas revenues (commodity and demand) collected by the LDC by customer class and the actual gas costs (commodity and demand) by customer class incurred by the LDC during the year. The reconciliation adjustment is to be calculated annually for each customer class by dividing the true-up amount by the forecasted sales volumes. This adjustment is to be included in customer bills for twelve months beginning September 1.

The New Mexico Commission regulations require each LDC with a purchased gas adjustment clause to conduct annually a reconciliation audit as soon as possible after the end of the accounting month of August.[12] The audit is intended to determine any under or overrecoveries of costs and includes the following costs and revenues. The distributor determines the total amount that it paid for gas, including substitute gas, to serve its customers. The LDC calculates the amount of gas costs recovered through its basic rates and the revenues received from the PGA clause. The distributor also calculates the customer share of any revenues that it received from processing of utility owned gas (either by the utility itself or by another party contracting with the distributor). Refunds made to customers during the latest PGA period and other revenues or credits that the LDC may have obtained from gas purchases or the PGA are determined. The reconciliation factor used to balance any under or overrecoveries is calculated by dividing the amount of under or overrecovery with interest by the number of units of gas sold during the latest PGA period. This true-up factor is then used in determining the PGA gas cost factor by the following January and is used until a new factor is calculated or the under or overrecovery balances out.

In New York, an annual reconciliation is performed for the twelve months ending in August. Refunds or surcharges are used to balance the over or underrecoveries for twelve months beginning in December. The North Carolina

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[11] Part 7825.2700: Purchase Gas Charges, Automatic Adjustment, Subpart 7: True-up Amount, Revision effective October 16, 1989.

[12] NMPSC Rule 640: Purchased Gas Adjustment Clauses for Gas Utilities; 640.27: Reconciliation Factor (1988).

Commission policy is to true-up the commodity portion of gas costs by comparing the billed with the filed costs. The demand portion of the costs is over or underrecovered depending on the amount of sales volumes. In North Dakota, South Carolina, South Dakota, and Tennessee, annual true-ups are conducted. The North Dakota Commission reviews and the South Carolina Commission audits reconciliation calculations. The Ohio Commission's gas cost recovery mechanism includes an adjustment to track monthly under or overrecoveries that result from the application of the expected gas cost (historic purchase volumes multiplied by expected rates). This adjustment, labeled the Actual Adjustment, is then audited to insure that proper costs are passed through.

In Oklahoma, deferred accounting is allowed by the Commission but not required. When deferred accounting is used by the LDC, true-up is performed. Deferred accounting is used in Washington. In Oregon, true-up is done with a balancing account that is amortized in rates over the following year. Stockholders have a risk/reward incentive of 20 percent as only 80 percent of the LDC's costs, revenues, and so on are placed into the account for the eventual calculation of the true-up. The remaining 20 percent provides the shareholders with a profit or loss, risk/reward incentive. In Rhode Island, the distributor files an annual PGA with changes allowed during the course of the year if the under or overrecovery is estimated to be greater than 1 percent of the previous year's gas revenues. The annual filing includes a true-up of the previous PGA recovery. In Texas, a surcharge or credit is used to balance out any under or overcollections.

The Pennsylvania Commission regulations require the LDC to submit certain information either when it makes a tariff filing or annually if it does not file for a change in rates.[13] This information includes total revenues received, total purchased gas expenses incurred, difference between these revenues and expenses, an explanation of how the incurred costs differ from the costs allowed by the Pennsylvania Code, and an explanation of how the incurred costs are consistent with the least-cost procurement policy required by Pennsylvania Code.

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[13] 52 Pennsylvania Code, Section 53.64, paragraph (i)(1)(i)-(i)(1)(v) (1985).

In Utah, the LDCs track their gas costs and make any adjustments through a pass-through procedure. Over and undercollections are recorded in Account 191. Hearings are held every six or twelve months as part of the pass-through and any imbalance in collections is balanced out over a twelve-month period. For one Utah LDC, the balance in the account is amortized on or about March 1 of each year. The year-end balance in the account is divided by the annual sales volumes to Utah customers incorporated in current rates to obtain a surcharge to be included in the rates for gas service. If the quotient obtained from this calculation is positive, it is added to the rates for each class of service. If the quotient is negative, it is then subtracted from the rates. In each succeeding month, the actual sales volume to Utah customers is multiplied by the surcharge rate (the quotient) to obtain the amount of revenue to amortize the balance in the account.

At the Virginia Commission, the actual cost adjustment (ACA) portion of the PGA is revised annually and used in the true-up. The over or underrecovery of costs for the previous twelve months is determined first by checking the actual costs and revenues for those months. This over/undercollection is added to any balances remaining from previous ACA factors and any over or underrefund amounts are transferred to the ACA. The sum (over/undercollection from last twelve months plus balances from previous ACA factors) is divided by the sales for the last twelve months to determine the new ACA factor. Gross receipts taxes are included in this new factor which is then applied to the next twelve-month period.

In West Virginia, the LDC files a monthly actual cost report with the Commission. At each PGA proceeding, there is a twelve-month true-up of actual to estimated costs. The Wisconsin Commission also uses a true-up procedure. The LDC places any over or undercollections in a refund account. At the end of the PGA year, the distributor must true-up any balance left in the account. The true-ups are audited by the Commission. In Wyoming, over and undercollections are amortized over the next PGA period. The LDC must pay interest to its customers at the rate of its last authorized rate of return if it has overrecovered its costs. If it has underrecovered, however, it cannot charge ratepayers any interest.

Treatment of Overcharges

The NRRI included several questions on the treatment of overcharges in the survey. Overcharges are an important topic when discussing the functioning of automatic adjustment clauses because they represent a problem if they are recurring. The above description of true-up procedures involves a process designed to balance out any overrecoveries or underrecoveries by LDCs of their costs. The discussion in this section follows that previous one by describing other types of commission policies and procedures intended to deal mainly with overcharges, but, as with the next question, with undercharges as well.

The authors asked the staff members to describe any monitoring procedures that their commissions used to assure that customers are not over or undercharged for purchased gas in the PGA. The responses, separated by the authors into four categories, are shown in Table 2-15. A couple of cautionary points about these four classifications should be mentioned. First, the distinctions are, in some sense, artificial. For example, LDC reports and filings are usually the basis for commission auditing and accounting of the distributor. Any type of commission oversight of the LDC depends on the utility providing the necessary information to be truly effective. Second, the fact that a commission is not listed in a category does not necessarily mean that it is not using that procedure at all. It does mean that the staff did not mention the commission in response to the question. LDC reporting/filing is again a good example. Distributors undoubtedly report or file data at all commissions but not all of the commissions mentioned LDC reporting/filing as a monitoring procedure.

As seen in the table, the commissions rely on audits more than any other procedure as a monitoring procedure to assure that customers are not over or undercharged. Twenty-five commissions use audits to monitor the PGA while nineteen use LDC reporting/filing and eight use accounting as their main monitoring devices. There is some variety in the manner with which the commissions use audits as a monitoring device. Some commissions perform audits in the field in addition to or in place of desk audits at the commission offices. Some commissions may perform audits on a regular basis, such as annually or semiannually. Other commissions may

TABLE 2-15

PGA MONITORING PROCEDURES USED BY COMMISSIONS*

Audits	Accounting	LDC Reporting/Filing	Other
Alabama	Alaska	Delaware	Arizona
Arkansas	Connecticut	District of Columbia	Kentucky
California	Florida	FERC	South Dakota
Colorado	Maryland	Illinois	
Delaware	Utah	Iowa	
FERC	Virginia	Louisiana	
Georgia	Wisconsin	Maine	
Idaho	Wyoming	Massachusetts	
Indiana		Minnesota	
Kansas		Nevada	
Mississippi		New Jersey	
Missouri		New Mexico	
Montana		New York	
Nevada		Oklahoma	
New Hampshire		Pennsylvania	
North Dakota		Rhode Island	
Ohio		Tennessee	
Oklahoma		Texas	
Oregon		West Virginia	
South Carolina			
Tennessee			
Texas			
Utah			
Washington			
Wisconsin			
(N=25)	(N=8)	(N=19)	(N=3)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

*Some commissions are listed in more than one column because they responded that they use more than one of these procedures.

conduct audits periodically or randomly, when the PGA is filed, or when they are thought to be necessary. Audits are frequently incorporated into the true-up reconciliation process as the commissions try to insure that the LDCs pass on only the appropriate costs. Comments on the auditing policies and procedures of specific commissions follow.

In Alabama, a monthly desk audit is performed of the PGA accounts including invoices and adjustments. The Arkansas Commission is required by state law to audit all utility automatic adjustment clauses at least once every eighteen months. The California Commission audits LDC prior-year expenses and revenues during the utility's annual cost allocation proceeding (ACAP). The result of the ACAP is an allocation of the LDC revenue requirement and any balances from the balancing account among the customer classes. The purpose of the audit performed during the proceeding is to verify the cost of purchased gas and to compare that cost to the prices paid by core customers. In Colorado, there is an annual hearing and audit of the PGA filings. The Delaware Commission conducts field audits of its jurisdictional distributors to review financial records. At the FERC, audits to review PGA-related data and records are done periodically by staff from the Office of Pipeline and Producer Regulation and the Office of the Chief Accountant. The Georgia Commission staff conducts desk and field audits. The Kansas, Mississippi, and South Carolina commissions conduct periodic audits.

In Indiana, the large gas distributors are audited quarterly by the consumer advocate, the Office of the Utility Consumer Counselor (OUCC), which audits other distributors annually. The Commission staff conducts an internal review and verifies the gas costs of the distributors audited annually by the OUCC. The Missouri Commission conducts an annual reconciliation audit of the distributor's deferred accounts to verify the accuracy of costs and revenues. The Montana Commission is developing its monitoring procedures although auditing is involved. The Nevada Commission staff performs an audit when the PGA is filed. The New Hampshire Commission's finance department performs gas cost audits. A reconciliation of costs and revenues is also done. The North Dakota Commission conducts annual audits. In Oregon, audits are done randomly. In Tennessee, the PGA is audited every two years. The Texas Railroad Commission performs biannual audits. The Washington Commission performs audits if necessary.

The Ohio Commission's gas cost recovery procedure includes an actual adjustment to track over and underrecoveries on a monthly basis. This adjustment is audited to insure that the appropriate costs are passed through. The Oklahoma Commission staff performs semiannual Fuel Audits, examining the documentation that the LDCs submit monthly in their PGA filings. In Utah, the LDC records all charges in Account 191 which is then audited. The Wisconsin Commission audits the true-ups that the LDCs must calculate at the end of the PGA year.

As shown in Table 2-15, reporting and filings by the LDC constitute the second most common type of PGA monitoring procedure used by commissions. In most instances the monitoring consists of examining the periodic PGA filings and/or LDC reports on gas costs, and the reconciliation filings. Descriptions of commission policies and procedures follow.

In Delaware, the LDCs submit monthly reports on the progress of cost recovery. Invoices listing gas and storage expenses are included. The Office of Accounting and Finance of the District of Columbia Commission reviews the monthly PGA filings to check the assignment of costs. Any appropriate adjustments are then made and a reconciliation is done annually. At the FERC, staff review in detail (by individuals and by computer program) the annual filings of actual cost data by the pipelines. The Illinois Commission staff reviews the monthly PGA filings for accuracy and reasonableness. The annual reconciliation filings are examined in the field, in the office, and in hearings. In Iowa, PGA filings are examined by Board staff. Annual reconciliations are also performed. The Louisiana Commission reviews PGA filings monthly. In Maine, LDCs file a cost of gas report each month. In Massachusetts balances in the deferred accounts are reported to the Department every month. Minnesota Commission regulations require LDCs to submit PGA reports monthly and annually.[14] Staff summarize the monthly reports every three months and submit the

[14] Part 7825.2910: Filing by Gas Utilities and Part 7825.2810: Annual Report; Automatic Adjustment Charges (1989 revision).

summary to the Commission. In annual reports, the distributors detail charges by customer class for the previous year beginning July 1 and ending June 30.

In Nevada, distributors file monthly reports on the status of any balances in Account 191. The New Jersey Board receives monthly reports on the PGA in which the LDC compares estimated with actual costs. The New Mexico Commission reviews monthly filings and annual reconciliations and reports. There is also a biannual continuation filing. The New York Commission also reviews gas cost filings monthly and reconciliations annually. The Oklahoma Commission staff verifies the monthly PGA calculations. The Rhode Island Commission reviews initial PGA filings and any revised filings that may be submitted during the year. Contracts also are examined. The Tennessee Commission and the Texas Railroad Commission review PGA filings when submitted. In West Virginia the LDC files actual cost reports with the Commission each month. Each PGA proceeding includes a twelve-month true-up. In Pennsylvania, larger Group One distributors are required to notify the Commission within thirty days of a change of 1 percent or more in total purchased gas costs. The Commission may then give notice and initiate an investigation into the proper rate levels.

Accounting procedures are the third type of monitoring device most often used by commissions to assure that customers are not undercharged or overcharged. Eight commissions are listed in Table 2-15 in this category. As shown below, "accounting procedures" almost always mean balancing or deferred accounting and usually also involve a true-up or some type of commission review of the accounts.

In Alaska, a balancing account is the monitoring procedure. Entries in the account are reviewed by the Commission quarterly. In Connecticut, deferred accounts are reviewed each August. The Florida Commission adopted a purchased gas adjustment clause procedure in Order No. 10237, issued August 26, 1981.[15] In that order, the Commission adopted a true-up procedure and also decided to incorporate deferred accounting into the PGA. The Maryland and Virginia Commissions both

[15] In re: Investigation of Purchased Gas Adjustment Clauses Utilized by Regulated Natural Gas Distributors, Docket Nos. 800645-GU, 800359-GU, 800380-GU, Order No. 10237, Issued August 26, 1981.

require the annual calculation of an actual cost adjustment (described above for Virginia) as part of their reconciliation processes balancing revenues with costs. This adjustment is intended to assure that customers are not over or undercharged. The Utah Commission, as mentioned above in the discussion of auditing, requires all LDC charges to be recorded in Account 191 which is audited. In Wisconsin, the LDC places all over or undercollections into a refund account. The utility is required to true-up any balance left in the account at the end of the PGA year. A balancing account procedure is used in Wyoming intended to correct any temporary over or underrecovery problems.

Three commissions, Arizona, Kentucky, and South Dakota, are listed in Table 2-15 as using other types of monitoring procedures. At the time of the survey, the Arizona Commission was studying staff proposals for improving monitoring and the Commission had hired outside consultants to conduct gas procurement reviews of the two largest distributors. The Kentucky Commission conducts annual PGA field reviews of the major LDCs, an informal process in which Commission staff members go to the LDCs to meet with company officials and examine information that supports distributors' PGA filings. The South Dakota Commission uses rate case review and tariff compliance checks as monitoring devices.

Having described the procedures that commissions are using to guard against the occurrence of overcharges (and undercharges), it is useful to know what the commissions do if overcharges happen. Are there explicit provisions in the PGA for making refunds to customers, are overcharges deducted from the next period's PGA charge instead, or is some other mechanism used? The responses are shown in Table 2-16.

Offsetting overcharges in the next period's PGA is clearly the preference of the commissions. Almost twice as many commissions use offsets as refunds (thirty-one versus seventeen). This perhaps is not too surprising a finding. The discussion of true-up procedures shows that in the course of reconciling revenues and costs many commissions factor any undercollections or overcollections into the next period's PGA in the form of a true-up adjustment. As almost all commissions have true-up

TABLE 2-16

PGA MECHANISMS USED BY COMMISSIONS TO RETURN OVERCHARGES TO CUSTOMERS*

Explicit Refund Provision in the PGA	Overcharges Offset in the Next Period's PGA	Other Mechanisms
Alabama	Alaska	Mississippi
FERC	Arizona	Wisconsin
Florida	Arkansas	
Illinois	California	
Indiana	Connecticut	
Iowa	Delaware	
Kentucky	District of Columbia	
Louisiana	FERC	
Maryland	Georgia	
Massachusetts	Idaho	
Minnesota	Kansas	
New Mexico	Louisiana	
New York	Maine	
Ohio	Missouri	
Rhode Island	Montana	
Tennessee	Nevada	
Virginia	New Hampshire	
	New Jersey	
	North Carolina	
	North Dakota	
	Oklahoma	
	Oregon	
	Pennsylvania	
	South Carolina	
	South Dakota	
	Texas	
	Utah	
	Washington	
	West Virginia	
	Wisconsin	
	Wyoming	
(N=17)	(N=31)	(N=2)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

*Some commissions are listed in more than one column because they responded that they used more than one mechanism.

procedures, many would thus be using that type of factoring adjustment to handle overcollections.

It is also noted in the true-up discussion that in some (if not most) cases the current PGA includes not only the amortization of the previous PGA period's under and overcollections, but also the remnants of other past PGA under and overcollections. Thus, there would be some institutional impetus (or inertia) to handle all overcharges in the established manner of including them in the next period's PGA. A related reason for commission use of offsets is that today's overcollection could be used to handle, in the course of the true-up reconciliation, yesterday's or tomorrow's undercollection. Comments on specific commissions follow, beginning with those offsetting overcharges in the next period's PGA. Many staff members offering additional explanation of their commissions' procedures referred, as might be expected, to true-up, deferred accounting, or amortization.

In Arizona, the PGA rate is based on any amortization needed to recover or refund the current balance plus projected gas costs. In Connecticut, overcharges are handled through deferred accounting. The Washington Commission also uses deferred accounting. The District of Columbia Commission's usual procedure involves a true-up performed each August with the difference between costs and recoveries passed on to the ratepayers in an actual cost adjustment. In a few cases, refunds have been given as a one-time credit. The New Jersey Board has a similar offset procedure, but the Board may require a one-time payment by the LDC of any refunds that the distributor had received and which the regulators felt could have a major impact on the PGA factor. Another option for the Board in such a case would be to refund part of that revenue and factor the rest into the PGA. In Nevada, supplier refunds to the LDC are placed in Account 191.

In Oklahoma, overcharges resulting from billing errors are corrected in a filing the month after their discovery. Producer and other refunds received by the distributor are amortized over a period of time. The Utah Commission policy allows LDCs to track costs and record under or overcollections in Account 191. These imbalances are then amortized over a twelve-month period. The Wisconsin Commission encourages LDCs to true-up frequently throughout the year so that any balances left in the refund account at the end of the period are small. True-up is required only at the end of the PGA year.

The District of Columbia Commission and the New Jersey Board are mentioned as two commissions that normally treat overcharges through offsets but may on rare occasions also order refunds. Other commissions answered that both options are routinely used. For example, FERC regulations allow both methods. Cash refunds are required, however, if the balance to be refunded equals or exceeds either $2 million or one cent per MMBtu (based on the most recent twelve months), whichever is less. The Louisiana Commission also provides for both methods. A combination of the two could be used depending on the type and size of the refund or adjustment to be made.

Commissions using refunds as their normal procedure for handling overcharges usually spread the payments over an extended period, generally twelve months. Refunds may be based on expected or past sales and may include interest in addition to the amount the LDC overcharged its customers. In Alabama, refunds are made if there are overcharges although the Commission may also order a flow through of the PGA if the LDC receives a refund from its supplier. In Indiana, refunds are allocated over one year based on expected sales. In Maryland, refunds are passed through directly to customers as soon as the LDC receives them from its suppliers. Refunds plus interest are paid to customers over twelve months. The amount paid in any one month is determined by the LDC's sales in that same month during the period toward which the refund applies.

New York Commission rules require a refund mechanism in each tariff. Supplier refunds are flowed through to customers with interest over twelve months. In Ohio, when the LDC receives a refund it is placed into a refund and reconciliation adjustment. If the overcharge is applied against the LDC's monthly bill, this amount is tracked through the actual adjustment as if it were part of the LDC's monthly cost of gas. In Tennessee, overcharges are refunded with interest in an annual filing. Virginia Commission policy requires the LDC when receiving a refund from its supplier to calculate a refund factor to be included in the PGA for the next twelve months. Large industrial customers may receive a refund check instead.

According to the New Mexico Commission's regulations, the LDC upon receiving a refund from its suppliers determines the period during which the gas cost factor used for billing its customers was higher than it would have been had the refunded amounts been included.[16] If the refund was received over a period longer than twelve months, the total amount is to be divided by the sales made during the PGA period to which the refund applies. If the refund was received over a period shorter than twelve months the utility may pay back its customers either over the months corresponding to the months in which the overcharge took place or over the same amount of gas sold during the time the overcharge occurred. The utility may also include the refund in the reconciliation factor.

Two commissions are listed in Table 2-16 as using other mechanisms to return overcharges to customers. Mississippi's procedures for returning overcharges are set out in the individual PGA tariffs as approved by the Commission. The Wisconsin Commission, in addition to the true-up procedure described above, provides for the payment to customers of any direct pipeline refunds under separate procedures and not through the PGA.

PGA Treatment of Direct Gas and Spot Gas Purchases

The increase in direct gas and spot gas purchasing by LDCs and other large customers has been one of the major developments as the gas market becomes increasingly competitive and open. These topics have been discussed in previous NRRI reports.[17] One of the reasons for conducting the current research was to examine how commissions were adapting their PGA procedures to the new more

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[16] NMPSC Rule 640: Purchased Gas Adjustment Clauses for Gas Utilities; 640.25: Surcharge or Refund Procedures (1988).

[17] See Daniel J. Duann, Robert E. Burns, and Peter A. Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, December 1989); see also Maria L. Mone, "The Natural Gas Industry: Are State Utility Commissions Protecting the Residential Consumer?" *NRRI Quarterly Bulletin* 11 (June 1990):161-175.

competitive environment. Thus, the authors included questions on PGA treatment of direct gas and spot gas purchases. In a 1989 survey, the NRRI found that direct gas purchase contracts frequently are reviewed in PGA proceedings. Staff members at thirty-three (of forty-nine surveyed) commissions told the NRRI then that their agencies review direct gas purchase contracts and twenty-three said they conduct the oversight during the PGA proceedings.[18] In short, the PGA procedure was an important means by which commissions are handling the new gas market.

To get some indication of the extent of LDC direct gas and spot gas purchasing, the NRRI in the later 1990 survey asked the staff members about the mix of gas supply sources for each LDC in their states. The respondents were asked what percentage of the distributors' purchased gas is from long-term pipeline sales gas, from long-term (more than one year) gas contracts with producers, from intermediate term (more than one month, less than one year) contracts with producers, and from the spot market (one month or less). Some examples of the LDC supply mixes provided by the respondents are given below.[19]

The data show that distributors indeed are taking advantage of the new market structures. Many LDCs are purchasing gas in the spot market and directly from producers. The data also help to point out the challenges that commissions face in this new environment. Different distributors within the same state are pursuing spot and direct gas at different levels. Michigan is a good example of a state in which a variety of LDC purchasing practices exist. Commissions thus need to maintain flexibility in their PGA policies and procedures to deal with this diversity of distributor purchasing practices while at the same time encouraging and possibly requiring the distributors to take advantage of the new opportunities to purchase lower cost (best cost) gas.

In Alabama, one LDC--Alagasco--has a supply mix of 41 percent long-term contracts with producers, 4 percent intermediate, and 55 percent spot. Another

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[18] Duann et al., *Direct Gas Purchases*, 68.

[19] As with the question on storage, discussed above, staff members provided a large amount of data. Interested readers are referred to question #2 in Appendix A of the separate volume available on request from the NRRI Publications Office.

distributor, MGSC, has a mix of 5 percent long-term and 95 percent spot. Arkansas LDCs have the following mixes: Arkansas Western Gas, 90 percent long-term from producers, 10 percent spot; Associated Natural Gas, 83 percent pipeline purchase, 17 percent spot; Arkansas Louisiana Gas, 4 percent pipeline purchase, 75 percent long-term from producers, and 21 percent spot; and Arkansas Oklahoma Gas, 90 percent long-term from producers, 10 percent spot. California distributors have the following mixes (classified by contract term): Pacific Gas & Electric, 35 percent long-term, 35 percent intermediate, and 30 percent spot; Southern California Gas, 64 percent long-term, 2 percent intermediate, 34 percent spot; San Diego Gas & Electric, 15 percent long-term, 5 percent intermediate, and 80 percent spot. In Connecticut, the distributors generally have a mix of about 30 to 35 percent spot with the remainder of the supply coming from long-term pipeline purchases. In Delaware, Chesapeake Utilities purchases all of its gas from its subsidiary, Eastern Shore Natural Gas. Delmarva Power & Light had the following mix in 1989: 29 percent long-term pipeline, 21 percent intermediate term sales, 50 percent spot.

In Idaho, one LDC has a mix of 75 percent long-term contract, 20 percent spot, and 5 percent other. The state's other distributor has a mix of 90 percent long-term contracts and 10 percent spot. Three large Illinois distributors had the following throughput amounts in 1988: NIGas-53.6 percent pipeline purchases, 21.2 percent direct purchases, 25.2 percent end-user transportation (49.5 percent of total throughput in the state in 1988); Peoples, 55.5 percent pipeline purchases, 20.5 percent direct purchases, 24.0 percent end-user transportation (25.7 percent of total throughput in 1988); Illinois Power, 37.6 percent pipeline purchases, 38.9 percent direct purchases, 23.6 percent end-user transportation (10 percent of total throughput in 1988). The supply mix for the entire state of Iowa is 63.2 percent from pipeline sources and 36.8 percent from other sources. Maine's one LDC purchases all of its gas from an affiliated pipeline which has a mix of 71 percent long-term and 29 percent spot. Three Maryland LDCs have the following mixes: Baltimore Gas & Electric, 53 percent pipeline, 30 percent short-term, 17 percent long-term; Washington Gas Light, 42 percent pipeline, 39 percent short-term, 19 percent long-term; Columbia of

Maryland, 56 percent pipeline, 23 percent short-term (producer), 21 percent long-term (producer).

In Michigan, five distributors (each with 10,000 customers or more) have the following mixes: Michigan Consolidated Gas Company, 37 percent pipeline, 43 percent producer, 20 percent spot; Consumers Power, 65 percent pipeline, 28 percent producer, 7 percent spot; Michigan Gas Utilities, 32 percent pipeline, 66 percent producer, 2 percent spot; Southeastern Michigan Gas Company, 22 percent pipeline, 59 percent producer, 19 percent spot; Michigan Gas Company, 31 percent pipeline, 41 percent producer, and 28 percent spot. In Mississippi, the largest distributor, Mississippi Valley Gas, has a mix of 39 percent long-term pipeline, 16 percent long-term producer, 24 percent intermediate producer, and 21 percent spot. Four New Jersey distributors had the following mixes in 1989: Elizabethtown Gas, 33.6 percent long-term pipeline, 24.8 percent long-term producer, 41.6 percent spot; New Jersey Natural Gas, 85 percent long-term pipeline, 15 percent spot; PSE&G, 31 percent long-term pipeline, 30 percent long-term producer, 39 percent spot; and South Jersey Gas, 31 percent long-term pipeline, 1 percent long-term producer, 68 percent spot. The overall mix for the state of North Carolina is 50 percent long-term and 50 percent spot.

In Pennsylvania, the eight largest (Group One) distributors had the following combined supply mix in the 1987 PGA year: 71 percent pipeline, 7 percent direct purchases from producers, 11 percent local purchases, 10 percent spot, and around 1 percent from other LDCs. Five distributors in South Carolina have the following mixes: United Cities, 10 percent long-term, 90 percent spot; Piedmont, 50 percent long-term, 50 percent spot; South Carolina Pipeline, 25 percent long-term, 5 percent intermediate, 70 percent spot; South Carolina Electric & Gas, 25 percent long-term, 5 percent intermediate, 70 percent spot; and Peoples, 25 percent long-term, 5 percent intermediate, 70 percent spot. The four largest distributors in West Virginia have the following mixes: Hope, 10 percent spot, 84 percent local producers, 6 percent pipeline; Mountaineer, 49 percent spot, 21 percent local producers, 30 percent pipeline; Cabot, 4 percent spot, 71 percent local producers, 25 percent pipeline; and Equitable, 13 percent spot, 3 percent local producers, 84 percent pipeline.

With respect to actual PGA treatment of direct and spot gas purchases, the NRRI first asked whether gas purchased directly from the producer by the LDC is treated differently in the PGA than gas purchased from other sources, such as the pipeline. This question perhaps would give some idea of how the new gas market conditions are affecting the commissions. If commissions are treating direct purchase gas differently, it might be an indication that they have had to change established procedures to respond to new developments. If the commissions are not treating direct purchase gas any differently, it may mean that the established procedures were sufficient and the commissions have not had to make major changes. The survey shows the latter possibility appears to be what is happening.

Two commissions, the FERC and Maryland, responded that their PGA treatment of direct purchase gas is different than the treatment of other gas. The FERC allows pipeline charges to be flowed through as billed while producer charges must be passed through in the commodity charge. The Maryland Commission requires the cost of direct purchase gas to be either the same or less than the cost of the displaced pipeline supply. The direct purchase obligation must not include minimum bills or take-or-pay costs.

In Pennsylvania, all sources of gas supply were included in calculating the average cost of gas for base rates when the PGA was initiated for larger Group One distributors. More recently, some LDCs are maintaining large industrial and commercial customers by serving them with cheaper direct or spot purchased gas while serving the core captive customers with the pipeline supply. The Commission has not formally approved this arrangement, however. The Commission has approved LDC allocations of pipeline demand costs away from the high load factor customers.

The NRRI then asked whether spot gas purchased by the LDC is treated differently in the PGA procedure than gas purchased from other sources. As with direct gas purchases, few commissions answered that there was a difference. Table 2-17 shows the three commissions that did.

In Georgia, spot gas is given priority over system supply for serving interruptible customers. The Maryland Commission, as with direct purchase gas, requires that the cost of spot gas should be either the same as or less than the

TABLE 2-17

COMMISSIONS WITH DIFFERENT PGA TREATMENT FOR SPOT GAS PURCHASED BY THE LDC

Georgia
Maryland
Oregon

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

pipeline supply gas that the LDC is replacing. The Oregon Commission uses historical spot gas prices without adjusting for known and measurable changes.

Commissions answering that there was no difference in treatment of spot gas include California. Spot gas may be included in the LDC's core portfolio, which generally consists of long-term gas supply. All core gas receives balancing account recovery and is subject to an annual prudence review. Only spot gas may be sold to noncore customers and the distributor is at risk for noncore sales. Maine's lone distributor buys all of its gas from an affiliated pipeline. The LDC does not buy spot gas, but its supplier does. The Commission tries to insure that the LDC is obtaining an optimal quantity of spot gas especially if that gas is cheaper than pipeline supply.

The authors asked the staff members whether their commissions have addressed the appropriateness of gas escalation provisions in LDC-producer direct gas purchase contracts. This question was intended to gauge the extent of commission consideration of another new gas cost related issue that could have significant impact on the PGA. As with the previous two questions, few commissions have addressed this issue. Table 2-18 lists the three commissions that have. The California

TABLE 2-18

COMMISSIONS THAT HAVE ADDRESSED APPROPRIATENESS OF GAS ESCALATION PROVISIONS IN LDC-PRODUCER GAS SUPPLY CONTRACTS

California
North Carolina
Oklahoma

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

Commission considers escalation provisions and all other terms of confidential supply contracts on a case-by-case basis. In North Carolina, all contracts for gas supply have escalation provisions. Thus far, however, the Commission has not addressed the reasonableness of these provisions. The Oklahoma Commission includes a prudence review in its semiannual gas cost reviews. The LDC's purchases must follow a Commission priority scheme emphasizing distressed wells, enhanced recovery, stripper wells, dual completions, and others.

The Ohio Commission has not addressed the issue of gas escalation provisions specifically but would probably allow increased costs if they were appropriate given market conditions, the analysis that the LDC performed before entering into the contract, and the need to take gas from the source. The New York Commission has accepted contracts for filing but has not approved or commented on them. The FERC does not consider the issue unless fraud and abuse standards are involved.

PGA Incentive Mechanisms

The next topic considered is PGA incentive mechanisms. Incentive regulation involves providing the utility with a reason to do something (in the case of the PGA to minimize gas costs) instead of simply ordering the utility to do it. The incentive either can be positive (for example, allowing a utility to keep a certain share of revenues resulting from savings in costs) or negative (such as requiring the utility to absorb any increase in costs thought to have been imprudently incurred). Incentive regulation can be an important tool for commissions to use and can have particular relevance to purchased gas adjustments. An example of an incentive mechanism already mentioned is the Oregon Commission's policy of placing 80 percent of costs into the deferred balancing account to be trued-up while holding stockholders at risk for the other 20 percent.

The NRRI asked the staff members whether their commissions' PGA procedures include any incentive mechanisms. Table 2-19 shows the thirteen commissions that have such mechanisms. This rather small number indicates that this is an idea that has not really caught on with respect to the PGA. The incentives described below are both positive and negative. In several instances of positive incentives, commissions allow LDCs to keep or pass on to stockholders revenues resulting from cost savings or interruptible sales. Examples of negative incentives include commissions requiring distributors to pay interest on cost overrecoveries. Some staff members also mentioned commission oversight procedures and the possibility of a commission rejecting a PGA filing. These certainly would be negative incentives, theoretically possessed by all commissions, although of a somewhat different nature than the term "incentive regulation" usually signifies. Comments on specific commissions follow.

In Alabama, the Commission approves LDC direct purchases with producers or spot purchases on the condition that the commodity cost of the gas be less than that of the major interstate pipeline suppliers (the intent being to minimize costs through the commodity charge). In Alaska, estimated gas costs are calculated and a new PGA rate is established every January 1. If there is an underrecovery of costs,

TABLE 2-19

COMMISSIONS WITH PGA INCENTIVES
INTENDED TO MINIMIZE PURCHASED GAS COSTS

Alabama	Montana
Alaska	Oregon
Arkansas	South Dakota
California	Virginia
Indiana	West Virginia
Kentucky	Wyoming
Maine	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

interest accrues at the current prime rate. If there is an overrecovery, the LDC must pay interest at the level of its last authorized return. The Arkansas Commission allows one distributor to retain 40 percent of the savings resulting from spot market purchases.[20] The LDC is required to have a weighted average cost of gas lower than a prespecified amount and/or to convert more than 15 percent of its contract demand with its pipeline supplier from firm sales to firm transportation. In converting its contract demand, the LDC must achieve a weighted average cost of gas lower than what the pipeline supply would have been. In addition to sharing in the savings, the LDC also receives the incentive that the cost savings would not be counted as a reduction in its revenue requirement in any future rate proceeding.

[20] In the Matter of the Application for a Rate Freeze and Related Rate Making Proposals of Arkansas Louisiana Gas Company, a Division of Arkla, Inc., Docket No. 85-043-U, Sections 2.2 and 2.3.

The California Commission incentive consists of the regular annual prudence review. The Commission has rejected a proposal to place the distributor at risk for a fixed percentage of its forecasted gas costs. Electric utilities in California, however, are at risk for 9 to 22 percent of their forecasted fuel costs. The Indiana Commission incentive is its power to approve or disapprove proposed LDC gas cost adjustments. According to the Indiana Code,[21] the Commission may approve the utility's filing after finding the LDC has made "every reasonable effort" to acquire gas and provide retail service at the lowest reasonable cost. The filing must not result in the LDC earning a return greater than its last approved rate of return. In addition, the utility's estimate of its future gas costs must be reasonable and take into account its actual costs during the latest gas cost adjustment period and the costs recovered by the adjustment during that period. The utility thus has an incentive to keep its costs low in order to obtain the Commission's approval for its filing. The West Virginia Commission incentive is similar. The West Virginia Code requires the Commission,[22] before granting any rate increase to the distributor, to determine that dependable cheaper supplies of gas are not available. The distributor has the burden of proving that cheaper gas is not available. If the LDC fails to make its case, the Commission is required to grant an increase no greater than what it determines to be the reasonable cost of readily available gas.

The Kentucky Commission has issued a policy statement urging LDCs to acquire the cheapest gas available consistent with reliability. The Commission oversees LDC purchasing in PGA proceedings and rate cases to insure compliance. In Maine, the LDC has an incentive to promote interruptible sales as 10 percent of the profits from such sales are paid to stockholders. Firm ratepayers receive the other 90 percent. The LDC also has the incentive to keep costs down because of competition from alternative fuels, such as oil and wood. In Montana, the incentive is that the unreflected account balance is not allowed to accrue interest. The Oregon Commission, as noted above, places stockholders at risk (or reward) for 20 percent of

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[21] See the Indiana Code at IC 8-1-2-42(g)(3)(A-D).

[22] West Virginia Code, Section 24-2-4c.

the distributor's deviations from projected gas costs. In South Dakota, one distributor is allowed to recover only 90 percent of any cost increase, but has to pass through only 90 percent of any decrease.

The Virginia Commission has a risk or margin sharing mechanism to share nongas revenue earned from LDC interruptible sales. A margin, equivalent to the interruptible nongas cost of service, is established and any revenue in excess of the target is divided between firm ratepayers and stockholders. The ratepayers receive 90 percent and the stockholders 10 percent. The nongas margin consists of the difference between the interruptible rate charged and the cost of the gas sold to the interruptible customers. To increase this margin, the distributor must keep its gas costs low because a ceiling on the interruptible rate and the use of alternate fuels by the interruptible customers foreclose other options to the utility. Commission staff have also concluded that factors such as stronger Commission oversight of LDC gas purchasing, gas audit, review processes, rate design, and competition should help ensure efficient gas purchasing by the LDCs. In Wyoming, state law provides an incentive mechanism.[23] If the LDC's cost of gas decreases, at least 90 percent of that decrease is to be passed on to consumers. The distributor may add to its rates up to 10 percent of the difference between the old cost of gas and the new cost.

Some commissions responding that there are no incentive mechanisms in their PGA procedures offered additional comments. At the FERC, intervenors frequently raise the topic of incentives during proceedings covering purchasing practices. The Commission considers the issue in hearings. In Ohio, audits covering the accounting in the gas cost recovery filings and LDC management performance are conducted. These management audits are performed biennially for the larger distributors that serve more than 5,000 customers. The audit is done by outside consultants that have been chosen by the Commission and covers such areas as purchasing strategies, use of transportation, contract renegotiation, peak-day requirements, LDC participation at the FERC, minimization of unaccounted-for gas, procurement management and any other areas related to the cost of gas. The Pennsylvania Commission requires, as part of

[23] Wyoming Statute 37-3-115: Rates: less expensive source of supply.

the annual reconciliation, that interest at the current home mortgage rate be paid by the LDC to ratepayers on any overcollections resulting from the PGA. The South Carolina Commission has annual hearings to review gas costs.

The NRRI asked the staff members whether the incentive mechanisms for minimizing purchased gas costs have been effective. Many of the staff feel that the incentives are working well although no scientific or quantitative studies of the effectiveness have been conducted. For example, the Arkansas staff feels that the Commission has provided the LDC with an incentive to purchase at the lowest cost by allowing it to keep 40 percent of the savings, but effectiveness of the incentive has not been evaluated. The California Commission, in the annual prudence reviews, has found distributors imprudent and disallowed recovery of costs. For example, in one case the Commission ordered a distributor to factor approximately $6 million in losses that it incurred on the resale of gas into the costs associated with fuel switchable customers. Thus, the LDC will be responsible for absorbing those costs to the extent that the market will not. The staff feels that this decision provides an incentive to distributors not to purchase gas and try to resell it for less than the cost.

The Maine Commission staff feels that the incentive of allowing a share of interruptible sales profits to be passed on to stockholders has been successful. The interruptible profit pass-through has been increasing, thus reducing the cost of gas adjustment. In West Virginia, utilities are using more locally produced and spot gas. Wyoming LDCs are taking advantage of open access transportation to shift to alternative supplies and the distributors are participating in cases at the FERC to secure lower gas costs from the pipelines. Staff at the Ohio Commission feel that the Commission's management audit program has been effective, although it lacks a PGA incentive mechanism for minimizing gas costs. One large LDC connected with three additional interstate pipeline suppliers and increased its use of locally produced and spot market gas after being audited.

Other PGA-Related Issues

The authors included several questions in the survey dealing with other issues or areas that the PGA might affect. The questions covered bypass, effects of the PGA on customer class allocations, treatment of affiliated gas suppliers, and the effects of the PGA on seasonality of gas costs, transportation service rates, back-up service rates, and the availability of unbundled gas supplies for direct purchases by end-users. These topics are discussed in four subsections below.

PGA and LDC Bypass

The NRRI asked staff members a three-part question dealing with the potential effects of the purchased gas adjustment on bypass of the local distributor and end-user conversion from sales to transportation service. These issues reflect important new market conditions facing LDCs and their regulators. The prospect of end-users, particularly large industrials that make significant contributions to LDC cost recovery, leaving the LDC system entirely or cutting back on service is of major concern to distributors and commissions. Thus, the authors felt it was necessary to ask whether commissions have considered these issues.

The authors asked the staff members first whether their commissions have addressed the possibility that their PGA policies encourage bypass. As Table 2-20 shows, only a few commissions have considered this question. Seven commissions are listed in the table.

In Arizona, bypass has been addressed for one LDC and is under consideration for the other major LDC. The issue has not been fully resolved, however. The Kentucky Commission considers bypass on a case-by-case basis as the question arises. The Minnesota Commission has considered bypass in rate cases. The Oklahoma Commission, in order to avert bypass, has authorized special gas sources that have no PGA adjustments from the base cost of gas. The Florida Commission approved a special arrangement for LDCs to use to retain interruptible customers with fuel

TABLE 2-20

COMMISSIONS THAT HAVE CONSIDERED WHETHER THE PGA ENCOURAGES BYPASS

Arizona	Kentucky
California	Minnesota
Florida	Oklahoma
Idaho	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

switching capability.[24] The Commission allowed LDCs to initiate contract-interruptible service. The distributor can offer the customer a contract rate as low as the cost of gas plus any customer charges to compete with alternative fuels.

The authors asked staff members whether their commissions have considered the possibility that their PGA policies have encouraged end-user conversion from sales to transportation service. As Table 2-21 shows, slightly more commissions have considered this question than the previous one about bypass. Eleven commissions are listed.

The Arizona Commission is considering this issue. In California, the industry's regulatory restructuring includes not only the core-noncore customer arrangement but also a modified fixed-variable rate structure intended to make distributors indifferent to customer choices of sales or transportation. Noncore customers may purchase gas from marketers, producers, or the LDC. If the customer purchases from the

[24] In re: Petition of Peoples Gas System, Inc. for Approval of Modifications to Its Rate Schedule IS, Docket No. 850203-GU, Order No. 15228, Issued October 9, 1985.

TABLE 2-21

COMMISSIONS ADDRESSING WHETHER THE PGA AFFECTS END-USER CONVERSION FROM SALES TO TRANSPORTATION SERVICE

Arizona	Minnesota
California	North Carolina
FERC	Ohio
Florida	Oklahoma
Idaho	Rhode Island
Kentucky	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

distributor, it may buy from a thirty-day spot portfolio or make a one-year commitment to purchase from the core portfolio. The Commission has forbidden customers from switching back and forth between portfolios to whichever one is currently cheaper. The FERC has been considering changes in the recovery of third-party transportation costs. Transportation of sales gas is bundled with the price of that gas in the PGA. For gas bought elsewhere and transported over other pipelines, the transportation costs currently are recovered only up to representative levels in rate cases. The FERC is considering allowing third-party transportation costs into the PGA because it is felt that the costs are not being recovered fully or quickly enough under the current method.

The Idaho Commission has encouraged LDC transportation of gas by setting rates for that service allowing distributors to cover their costs. This enables the large industrial customers to benefit from cheaper sources of supply. The Kentucky Commission considers this issue on a case-by-case basis as it arises. The Minnesota

Commission designs transportation tariffs with the intent that they be neutral with respect to encouraging customers to switch from sales service. In Ohio, conversion from sales to transportation has been examined in management audits. The Ohio Commission has promoted the use of transportation service, a policy that has resulted in a leveling off of bypass. The higher cost of pipeline supply has encouraged the large industrial and commercial customers to switch to transportation. The Oklahoma Commission has allowed conversion from sales to transportation.

The third part of the question asked by the NRRI was whether the commissions have examined the PGA pass-through of take-or-pay liabilities or gas inventory charges with respect to whether such policies encourage bypass or the increased use of transportation service. Table 2-22 shows the eleven commissions that have considered this question.

The California Commission authorized certain transportation customers to pay lower rates that covered the variable costs of service only. The Commission took this action because transition costs associated with the changing market structure, including take-or-pay, were being collected in the transportation rates and some customers were threatening to bypass the LDC. The Illinois Commission has considered the impact of take-or-pay on bypass and concluded that potential bypass customers under special contracts would not be assessed take-or-pay costs.[25] In Iowa, take-or-pay liability is collected on the basis of total throughput including transportation. The Kentucky Commission considers the issue on a case-by-case basis. The Minnesota Commission is addressing the take-or-pay issue in a generic docket. The Ohio Commission has tried to allocate take-or-pay costs to transportation customers. The staff feels that some of these customers may return to sales service because of their need for gas and inability to deal with service interruptions.

In its order the Virginia Commission authorized automatic PGA recovery of take-or-pay demand surcharges in the same way that contract demand charges are recovered.[26] The Commission decided not to allocate take-or-pay costs both to firm

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[25] Docket No. 88-0103.

[26] Case No. PUE880028.

TABLE 2-22

COMMISSIONS ADDRESSING
THE EFFECTS OF TAKE-OR-PAY AND
GAS INVENTORY CHARGES ON
BYPASS AND TRANSPORTATION

Arizona	Iowa
California	Kentucky
FERC	Minnesota
Florida	Ohio
Idaho	Virginia
Illinois	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

and interruptible commodity costs because it felt such a policy would impair the LDC's ability to retain interruptible customers. Recovering take-or-pay on the basis of estimated transportation volumes and commodity sales also was rejected because the Commission felt the alternative would harm the ability of the LDCs to compete with alternative fuels.

The small number of commissions listed in Tables 2-20, 2-21, and 2-22 indicates that many regulators have not addressed the issues of bypass or end-user conversion in the context of the PGA. In some states, such as Nevada, the issues may not have arisen. The commissions, however, may have taken other action with respect to those areas. Some commissions that answered negatively to the questions provided additional explanation. For example, the Pennsylvania Commission has considered bypass, transportation, and recovery of take-or-pay costs but not as they relate to the PGA. The Commission has issued a policy statement that take-or-pay costs are not gas costs and not recoverable through the PGA. In Mississippi, some distributors have created spot-market gas pools with Commission approval. These are separate from the PGA and are intended to avoid bypass.

The state of Indiana has enacted an antibypass statute defining any person, corporation, or other entity engaged in the transportation of gas as a public utility and requiring that party to obtain a certificate from the Indiana Commission before transporting.[27] Transportation would include transporting gas from outside Indiana for direct sale or delivery to any end users in the state, transportation solely within the state on behalf of any end user or transportation by an end user in Indiana of gas owned or acquired by that consumer for use in the state. The Commission must determine that the public convenience and necessity are served by the proposed transportation, taking into consideration the availability of service from any gas utility authorized to serve end users in the area covered by the application. The New York Commission has issued an order directing that take-or-pay charges be allocated to transportation services.[28]

PGA and Customer Class Allocations

The NRRI asked staff members whether their commissions have considered the effect that the PGA will have on customer class allocations. In light of the gas market restructuring that has been occurring and the division of customers into core and noncore, captive and noncaptive categories, the questions of how costs are allocated among these groups and the proper burden for each customer class to shoulder are timely and important. As Table 2-23 shows, a significant number (although still a minority) of commissions have considered customer class allocations. Seventeen commissions are listed. The comments, provided by staff and described below, cover such areas as allocation of certain costs to core customers. Demand and take-or-pay charges are examples. Allocation of certain supplies of gas to core

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[27] See the Indiana Code at IC 8-1-2-87.5.

[28] Opinion No. 89-41: Opinion and Order Determining Take-or-Pay Recovery Mechanisms and Cost Allocations, Issued December 11, 1989.

TABLE 2-23

COMMISSIONS THAT HAVE ADDRESSED THE EFFECT OF THE PGA ON CUSTOMER CLASS ALLOCATIONS

Arizona	North Carolina
California	Ohio
District of Columbia	Oregon
Indiana	Pennsylvania
Iowa	Utah
Kentucky	Virginia
Maryland	West Virginia
Minnesota	Wisconsin
New Hampshire	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

customers is also noted. Respondents mentioned various protective devices such as the California Commission prohibiting noncore customers from switching from one supply portfolio to another or the use in Iowa of separate PGA clauses for different customer classes.

In Arizona, one distributor has a two-tier arrangement with lower cost gas allocated to price-sensitive customers. The Commission is inquiring into the appropriateness of this arrangement. In California, PGA undercollections are included in the cost of gas of the core portfolio which core customers must pay. Noncore customers may buy from marketers, producers, or from the utility. If a noncore customer buys from the utility, it may purchase gas from the core portfolio (making a one-year commitment to do so) or from the thirty-day spot portfolio. In the spot portfolio, the customer and the utility are at risk for the supply and the price. The Commission has forbidden noncore customers from switching from one portfolio to another to get a lower price. The District of Columbia Commission requires interruptible and special contract customers to be charged rates based on alternate sources of energy. Firm ratepayers receive 90 percent of the margins from such sales and the PGA applies only to firm customers.

The Indiana Commission allocates all demand costs to customer classes on the basis of demand allocation factors from the distributor's most recent rate case. In Iowa, separate PGA clauses exist for different customer classes. The Kentucky Commission has approved the pass-through of take-or-pay liabilities to core customers. In Maryland, core customers are charged the cost of gas associated with peak-day demand. In Minnesota, gas costs are rolled together unless some are specifically allowed in a case-by-case approach. The New Hampshire Commission staff and the LDCs developed a marginal-cost methodology for the LDCs to use. In North Carolina, fixed costs are passed on to all customers. The Ohio Commission's transportation policy mandates that supplies covered by the PGA are to be reserved for the core customers and for any transportation customers who pay for stand-by service. Customers not purchasing LDC system supply or stand-by service thus are not entitled to system supply and may have to pay an incremental cost to receive sales service once again from the LDC.

In Oregon, a single weighted average gas cost is calculated for core customers in the PGA. Most noncore customers transport their own gas. In Utah, one LDC's demand charges are allocated among customer classes on the basis of the percentage change in demand. Commodity costs are assigned on a commodity basis. The West Virginia Commission requires allocating pipeline demand charges (D-1) to core customers. As noted in the discussion of spot and direct gas purchases, the Pennsylvania Commission has noticed that some distributors maintain large industrial and commercial customers on their systems by serving them with cheaper gas from direct or spot purchases while serving core customers with pipeline supply. The Commission has not formally approved these arrangements, however. Regulators have approved some allocations of pipeline demand costs away from high load factor customers.

The Wisconsin Commission has issued an order reaffirming the use of the PGA with a one-for-one collection of gas costs and with a true-up mechanism and a true-up of the true-up to account for over and undercollections.[29] The Virginia Commission procedure includes all interruptible sales and purchases in the PGA calculations. During a rate case, a base cost of gas is developed for each customer class and (on an aggregate basis) for firm and interruptible customers. A common adjustment factor is developed for firm and interruptible sales by projecting the quarterly firm and interruptible gas costs and then subtracting the respective aggregate base costs of gas. The base cost would be reestablished annually for each class at the time of the actual cost adjustment filing and would include the allocation factors set in each company's most recent rate case.

PGA and Affiliated Gas Suppliers

The NRRI asked staff members about the treatment of affiliated gas suppliers in the PGA process. Utility procurement of fuel from affiliated suppliers is a major concern for regulators not just in the gas area but also in electricity. Commissions want to insure that the utility is paying a fair market-level price for the fuel and not a price that is set higher than the market with the intent of having the utility and thus ratepayers subsidize the affiliate's operation.[30] The authors asked how affiliated gas suppliers are treated in the PGA. Twenty-seven commissions, listed in Table 2-24, have the same PGA treatment for affiliated suppliers as for nonaffiliated suppliers although in a few of these cases, such as California, New York, and Ohio, examination of the affiliated transactions is more stringent. Closer examination of affiliated transactions is not unique to those three commissions, however, as the following discussion shows.

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[29] Investigation on the Commission's *Motion into the Need for Planning Review, Changes in Rate Design, Changes in Purchased Gas Adjustment Clauses, Accounting Changes, and Related Matters for Natural Gas Distribution Utilities in Wisconsin*, Docket No. 05-GI-102, February 23, 1989.

[30] For a discussion of these issues mainly with respect to electric utilities, see Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986).

TABLE 2-24

COMMISSIONS WITH THE SAME PGA TREATMENT OF AFFILIATED AND NONAFFILIATED SUPPLIERS

Alabama	Montana
California	New Hampshire
Connecticut	New Mexico
Georgia	New York
Idaho	North Carolina
Illinois	North Dakota
Indiana	Ohio
Iowa	Oklahoma
Louisiana	South Dakota
Maine	Texas
Maryland	Utah
Massachusetts	West Virginia
Minnesota	Wyoming
Missouri	

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

Beginning with those commissions in Table 2-24 that offered additional comments on their policies and procedures, the California Commission subjects utility purchases from subsidiaries and purchases from other sources to the same arm's-length standards. As noted above, the affiliated transactions are more closely examined. In Missouri, the annual reconciliation audit examines all bids received by the LDC to determine if a fair price was received by the distributor. Affiliated transactions are treated routinely at the North Dakota Commission unless some reason for additional investigation arises. In Ohio, purchases from affiliated suppliers are examined to assure that the terms and conditions are the same as or no more favorable than those offered by the LDC to nonaffiliated suppliers. There is no other difference in the Ohio Commission's treatment, particularly with respect to how the purchases are passed through the PGA. The Texas Railroad Commission treats affiliated suppliers the same as nonaffiliated suppliers in rate proceedings. The Commission does not hold PGA proceedings. The West Virginia Code requires the LDC to prove that its contracts with all of its suppliers are negotiated at arm's length.[31] If a distributor purchases more than 50 percent of its system supply gas from an affiliate, any PGA increase would be based on actual costs and may be subject to general rate case requirements and review.

Other commissions offering additional comments include Arkansas. Affiliated gas purchases are reviewed in mandatory compliance audits. In the past, the Commission has set the price for company-owned production on the basis of a "fair field price" or the fair price of nonaffiliated production in the gas field. In Delaware, the distributor Chesapeake Utilities Corporation purchases gas from its subsidiary, Eastern Shore Natural Gas. Sales from Eastern Shore to Chesapeake are based on rates approved by the FERC and the costs are passed through Chesapeake's PGA. The District of Columbia Commission does not include affiliated gas suppliers in the PGA. The FERC closely monitors affiliated relationships and required suppliers to be separately identified. Similar to the "fair-field-price" practice used by the Arkansas Commission, the FERC may impose a cap on the prices paid to an affiliate basing this cap on the prices paid to nonaffiliates in the same area. The Kentucky Commission requires additional proof that the prices charged by the affiliate to the LDC are reasonable. Mississippi state law requires the disclosure of significant affiliated transactions.

In New Jersey, affiliated gas supplies are priced at rates reflecting the average cost of gas of the state's major suppliers. In Oregon, no major affiliated transaction involving sales of gas to LDCs have occurred. In one minor case, the transaction was priced at the distributor's weighted average cost of gas. The Washington Commission requires that affiliated transactions be approved through formal rate case proceedings

[31] West Virginia Code, Section 24-2-4c.

and affiliated interest orders. The Pennsylvania Commission requires any major Group One distributor buying gas from an affiliate to submit additional information proving that the transaction is part of a least-cost purchasing policy. According to the Pennsylvania Code, this additional information includes a comparison of the cost of the gas from the affiliated source with the average market price of gas from pipelines and other sources, estimates of the quantity of gas available to the LDC from all sources, the efforts made by the LDC to obtain gas from nonaffiliated sources, and the reasons why the LDC is purchasing from the affiliated source.[32] The South Carolina Commission allows two LDCs to recover the costs of affiliated gas purchases through the PGA.

The NRRI next asked if any minimum take provisions exist that affect PGA recoveries from affiliated suppliers. Such provisions appear to be rare or at least the commissions are not aware of any, as the responses in Table 2-25 indicate. Only three commissions, California, the FERC, and New York, said that there are minimum take provisions. The California Commission has noted the presence of minimum takes both in low-and high-cost gas contracts, but has not found these purchases to be imprudent. The FERC has no specific guidelines on this type of contract provision other than a general policy against them and its prohibition against giving more favorable treatment to affiliates over nonaffiliates. In New York, one or two utilities have minimum take provisions in affiliated supplier contracts. The New York Commission does not have any special PGA procedures or a different true-up to handle these provisions.

PGA and Other Costs and Rates

The NRRI included a multipart question covering a variety of rates and costs that might affect the competitiveness of gas service, asking staff members whether their commissions have considered how their PGAs affect seasonality of gas costs, transportation service rates, back-up service rates, and the availability of unbundled

[32] 52 Pennsylvania Code Section 53.65 (1985).

TABLE 2-25

COMMISSIONS REPORTING MINIMUM TAKE PROVISIONS THAT AFFECT PGA RECOVERIES FROM AFFILIATED SUPPLIERS

California
FERC
New York

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

gas supplies for direct purchase by end-users. As seen in Table 2-26, about one-quarter of the commissions have considered seasonality. Smaller numbers have addressed the other issues. Comments on specific commissions follow.

Twelve commissions are listed in Table 2-26 as having considered the effects of the PGA on seasonality of gas costs. In California, core residential rates are not seasonal because the one-year price stability of the PGA applies only to part of the supply. Prices for other parts of the gas supply change at least seasonally. The FERC has addressed seasonality through the use of quarterly PGAs. In Maine, separate winter and summer cost of gas adjustments are used. The Massachusetts Department's cost of gas adjustment also includes a seasonal cost component. The New Jersey Board is considering seasonality. The North Carolina Commission has addressed seasonality with respect to storage costs in rates. The Virginia Commission PGA provides for spreading demand costs over the whole year through a fixed rate per unit of firm gas consumption over all four quarters of the year. This treatment is intended to avoid a disproportionate amount of the demand costs being factored into the summer quarter and thus major price swings between winter and summer. The Wisconsin Commission has addressed seasonality and the other issues on a case-by-

TABLE 2-26

COMMISSIONS THAT HAVE ADDRESSED PGA EFFECTS ON CERTAIN SERVICE AND RATE AREAS

Seasonality of Gas Costs	Transportation Service Rates	Back-up Service Rates	Availability of Unbundled Gas for Direct Purchase
California	FERC	Arizona	California
FERC	Kentucky	California	FERC
Maine	Maryland	Maryland	Missouri
Massachusetts	Missouri	Missouri	New Jersey
Missouri	New Jersey	Ohio	Ohio
New Hampshire	North Carolina	West Virginia	Wisconsin
New Jersey	West Virginia	Wisconsin	
North Carolina	Wisconsin		
Ohio			
Oklahoma			
Virginia			
Wisconsin			
(N=12)	(N=8)	(N=7)	(N=6)

Source: NRRI survey on public utility commission purchased gas adjustment clause practices, 1990.

case basis. Demand or reservation charges are given annualized treatment while commodity charges are seasonal. Storage costs are factored into winter rates. The Missouri Commission addresses seasonality and all of the other issues listed above in rate cases. PGA clauses also include these items.

With respect to transportation service rates, eight commissions responded that they have addressed the PGA effects. The FERC has addressed this issue in its

Order 436/500 series. The Kentucky Commission addresses transportation issues in rate proceedings. In Maryland, transportation rates are designed to be equivalent to the retail sales rate of the pipeline less the commodity cost of the gas and any demand/reservation charges. The New Jersey Board currently is considering transportation rates. In North Carolina, transportation customers can switch to sales service in winter. The West Virginia Commission has approved an allocation of part of pipeline demand charges (D-2 charges) to transportation customers. In Wisconsin, transportation service rates include certain costs such as demand and reservation fees and are adjusted as costs change.

Seven commissions have addressed the effects of the PGA on back-up service rates. They include the Arizona Commission, which recently approved such rates for one LDC's interruptible transportation service. The rates are being implemented. Back-up service is being considered by the California Commission in a review of its market restructuring program. The Maryland Commission requires back-up rates to be compensatory, recovering the demand or reservation charges and other incremental costs of the standby service. In Ohio, back-up service rates are based on the demand costs but may also include gas inventory charges and take-or-pay charges. Pipeline demand charges are also included in back-up service rates in West Virginia. Reservation charges are annualized in Wisconsin.

The final issue is the availability of unbundled gas for direct purchase. Staff at six commissions said that their agencies have considered this issue. In California, unbundling sales from transportation was the Commission's treatment of this issue. The FERC has addressed this issue in Order 436/500. With respect to all of the topics asked about in this question, the Commission has been issuing statements and pursuing its policies in rate cases more so than in the PGA. The New Jersey Board is considering this issue. In Ohio, some distributors buy gas on behalf of certain end users. The Ohio Commission reviews these purchases in management audits, comparing the prices paid with the price paid for spot gas recovered through the PGA. In Wisconsin, some distributors share pools of spot gas in which the cost of the gas is set monthly depending on the delivered price. The Virginia Commission has not addressed this issue of unbundled gas for direct purchase but the staff feels that the Commission's Generic Transportation promotes the unbundling of rates because the industry is becoming more competitive.[33]

Summary

Responses were received from forty-eight state utility commissions, the District of Columbia Commission, and the Federal Energy Regulatory Commission. Almost all of these commissions (forty-eight) have purchased gas adjustment clauses. Only two state commissions, Michigan and Vermont, do not have PGA clauses. Most commissions, twenty-seven, have a generic rule or order providing a uniform procedure for all of the LDCs under their jurisdictions. Twenty commissions treat PGA on an ad hoc basis. Two commissions use both methods, generic treatment and ad hoc. The PGAs at forty-seven commissions are long-standing (five or more years old).

With respect to commission treatment of distributors' PGA filings, the NRRI found that most commissions require the LDC to file with a set frequency. Forty-one commissions have this requirement. Several others do not mandate filings on a set schedule but still require the LDC to furnish data at some time, such as when costs change by more than a prespecified percentage. The required frequencies of filing vary by commission. Annual filings are the most common type. In order of their use, monthly, semiannually, and quarterly are the next most common types. Basic data to be included in filings include commodity costs (purchased gas costs), demand costs, projected costs, and purchases for the upcoming PGA period; actual costs for the past PGA period; revenues received from each customer class; and quantities of gas purchased and sold. Commissions vary by type and amount of data to be filed.

Most (thirty) commissions hold hearings on the PGA filings. Thirteen commissions hold hearings on every filing while seventeen do so only on certain filings. Commissions holding hearings on certain filings generally take such action on

[33] Order Case No. PUE860024.

disputed or new or unusual items in the PGA. Filings of the larger distributors may also be the subject of hearings. Fourteen commissions are required to hold hearings at a set frequency. Annual and semiannual hearings are the most common. Most (thirty-five) commissions responded that their hearings are open to the public. None of the commissions responded that their hearings are closed. Twenty-three commissions give confidential protection to purchased gas contracts considered during the hearings. At eight of these twenty-three, however, confidentiality is granted only upon the request of the LDC or other interested party.

The commissions allow the basic types of costs to be recovered through the PGA. Practically all of the commissions include commodity costs, demand costs, and pipeline transportation charges. Take-or-pay and storage costs are allowed by fewer (but still a majority) of the commissions. Gas inventory charges are permitted by slightly more than half of the commissions. Few commissions permit administrative costs associated with fuel procurement to be recovered through the PGA. The responding commissions were nearly unanimous in saying that cost decreases are not treated any differently than cost increases and that cost decreases are passed through to customers as quickly as cost increases.

Thirty-two commissions require the LDCs to use particular accounting practices. Many require the use of either the FERC or NARUC Uniform System of Accounts. Forty-six commissions include a true-up procedure in their PGAs. Many commissions employ monitoring devices to prevent overcharges or undercharges of customers. Audits are the most commonly used technique with LDC reporting/filing and accounting also used. When overcharges occur, more commissions prefer to offset them in the next period's PGA instead of using a refund. Thirty-one employ offsets while seventeen use refunds.

The NRRI asked about the treatment of direct and spot gas in the PGA. Very few commissions (two in the case of direct purchase gas and three in the case of spot gas) said that such purchases merited different PGA treatment. Only three commissions have addressed the appropriateness of gas escalation provisions in LDC-producer direct gas purchase contracts.

Incentive mechanisms in the PGA are somewhat rare. Thirteen commissions said that they employ incentives, both positive and negative. Many of these commissions feel that their incentives are effective although no systematic study has been done.

Only a few (seven) commissions have addressed the possibility that their PGA policies encourage bypass. Slightly more commissions, eleven, have considered whether their PGA policies have encouraged end-user conversion from sales to transportation service and have examined the PGA pass-through of take-or-pay liabilities and gas inventory charges to determine if such pass-through encourages bypass or the increased use of transportation. In some instances, these issues have not arisen. The commissions may have also taken other action with respect to these areas instead of considering them in relation to the PGA.

Other findings can be briefly mentioned. Seventeen commissions have considered the effect that the PGA may have on customer class allocations. Twenty-seven commissions said in response to a question about PGA treatment of affiliated gas suppliers that they have the same treatment for affiliated as they do for nonaffiliated suppliers. Minimum take provisions that could affect PGA recoveries from affiliated suppliers appear to be rare. Only three commissions said that they had seen such provisions in affiliated supplier contracts.

In response to a question covering other types of rates and costs, twelve commissions have considered how their PGAs affect the seasonality of gas costs. Eight commissions have addressed the PGA effects on transportation service rates and seven have addressed the effects of the PGA on back-up service rates. Six commissions have considered PGA effects on the availability of unbundled gas for direct purchase.

Overall, the survey shows the commissions to be active in certain ways but less active or inactive in others. The commissions are quite active in fulfilling their traditional oversight function and trying to insure that the LDC recovers its prudently incurred costs. The commissions require the LDCs to file regularly and submit a fair amount of data on costs and revenues. Procedures are in place for tracking costs and for handling over and undercollections. The commissions are less active in the newer areas of bypass, direct and spot purchases, and incentive regulation, at least in terms of how these affect the PGA. For those who would like regulators to be more proactive and take the lead in responding to changing more competitive conditions, this latter conclusion might be troublesome. For those who want the commissions to safeguard the ratepayers and oversee the utilities, the results appear reassuring.

CHAPTER 3

CURRENT STATE AND FEDERAL FUEL ADJUSTMENT CLAUSE PRACTICES

This chapter describes state and federal utility commissions' electric fuel adjustment clause practices. The NRRI surveyed these agencies during 1990 to gather information on their current policies and procedures. Survey forms were sent to the public utility commissions in forty-nine states and the District of Columbia.[1] The authors also contacted the Federal Energy Regulatory Commission (FERC). Responses were received from all of these commissions. In this chapter, the authors discuss the results of the survey. Interested readers are also directed to Appendix B of this report for the survey instrument.[2]

The discussion takes the following form. The next section covers the extent to which commissions are using fuel adjustment clauses. The following section covers commission procedures on electric utility FAC filings. Subsequent sections cover costs allowed in the FAC and treatment of cost increases or decreases, required accounting practices, true-up and refund procedures, incentive mechanisms, and other FAC-related issues including ratemaking in a more competitive power market, FAC encouragement of self-generation, affiliated qualifying facilities (QFs) and independent power producers (IPPs), and QFs, IPPs and competitive bidding. The final section contains a summary of the major findings.

Commission Use of Fuel Adjustment Clauses

The authors began the survey with a series of questions on whether commissions use fuel adjustment clauses, and if so, how. The first question was whether their commissions have electric fuel adjustment clauses. As might be

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[1] The Nebraska Commission was excluded from the survey as it does not regulate electric utilities.

[2] Detailed survey responses are available in a separate volume on request to the NRRI Publications Office.

expected, the use of fuel adjustment clauses is fairly widespread. Table 3-1 shows the forty-two commissions that responded that they have FACs. Nine commissions responded that they do not have FACs. They are Idaho, Missouri, Montana, Oregon, Texas, Vermont, Virginia (which uses a projected fuel factor instead), Washington, and Wyoming. The Idaho Commission has never adopted such clauses because hydro power is a primary source of electricity and most power plants that burn coal are supplied by affiliated mines.

TABLE 3-1

COMMISSIONS WITH ELECTRIC FUEL ADJUSTMENT CLAUSES

Alabama	Massachusetts
Alaska	Michigan
Arizona	Minnesota
Arkansas	Mississippi
California	Nevada
Colorado	New Hampshire
Connecticut	New Jersey
Delaware	New Mexico
District of Columbia	New York
FERC	North Carolina
Florida	North Dakota
Georgia	Ohio
Hawaii	Oklahoma
Illinois	Pennsylvania
Indiana	Rhode Island
Iowa	South Carolina
Kansas	South Dakota
Kentucky	Tennessee
Louisiana	Utah
Maine	West Virginia
Maryland	Wisconsin

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

The NRRI then asked about the method of commission FAC treatment: whether a commission has a generic rule, order, decision, or case that provides for a uniform FAC for all of the state's electric utilities or whether the commission treats fuel adjustment clauses on an ad hoc basis with FACs varying from utility to utility. The commissions are almost evenly split between these two options. As shown in Table 3-2, twenty-three have a generic rule, order, decision, or case providing a uniform treatment while twenty treat FAC on an ad hoc basis. Some commissions (Florida, New Mexico, and Pennsylvania) use both methods and others (Michigan and South Carolina) use neither.[3]

Some commissions provided additional comments on their procedures. Maine and Minnesota commission staff members made similar observations. Both commissions have a rule providing the framework for the FAC but there may be adjustments or variations in specific instances. This is a widely shared view. The New Mexico Commission, for example, also has a rule providing a uniform treatment, and the regulation specifies that the Commission may make any modifications to the rule that it feels are needed.[4] The South Carolina Commission establishes FACs for each utility in separate orders, including identical FACs for different utilities.

The authors asked the staff members whether their commissions' FACs were recently established (within the last five years) or long-standing (five or more years old). As seen in Table 3-3, forty-one commissions have long-standing FACs. Only Arizona and Virginia (which uses a projected fuel factor) answered that they had recently established their adjustment mechanism.

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[3] Some clarification of the different numbers of commissions listed in Tables 3-1 and 3-2 is in order. As noted in the above discussion, forty-two commissions are listed in Table 3-1. Forty of these agencies are also found in Table 3-2. The exceptions are Michigan and South Carolina which responded that they use neither generic nor ad hoc approaches. Three commissions, Florida, New Mexico, and Pennsylvania, are listed twice because they use both approaches resulting in the three extra listings (43 listed, 40 different agencies) in that latter table.

[4] NMPSC Rule 550: Fuel and Purchased Power Cost Adjustment Clauses for Electric Utilities 550.4, Alteration, Amendment, or Modification (1988).

TABLE 3-2

TYPES OF COMMISSION TREATMENT OF FACs*

Commissions That Have a Generic Rule, Order, etc., Providing a Uniform FAC	Commissions That Treat FACs On An Ad Hoc Basis
Alabama	Alaska
District of Columbia	Arizona
FERC	Arkansas
Florida	California
Georgia	Colorado
Hawaii	Connecticut
Illinois	Delaware
Indiana	Florida
Iowa	Louisiana
Kansas	Maryland
Kentucky	Mississippi
Maine	New Hampshire
Massachusetts	New Jersey
Minnesota	New Mexico
Nevada	Pennsylvania
New Mexico	Rhode Island
New York	Tennessee
North Carolina	Utah
North Dakota	West Virginia
Ohio	Wisconsin
Oklahoma	
Pennsylvania	
South Dakota	
(N=23)	(N=20)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

*Some commissions are listed in both columns because they responded that they have a generic rule, order, decision, case, etc. providing for a uniform FAC and that they also treat fuel adjustment clauses on an ad hoc basis.

TABLE 3-3

COMMISSIONS WITH LONG-STANDING FACs

Alabama	Michigan
Alaska	Minnesota
Arkansas	Mississippi
California	Nevada
Colorado	New Hampshire
Connecticut	New Jersey
Delaware	New Mexico
District of Columbia	New York
FERC	North Carolina
Florida	North Dakota
Georgia	Ohio
Hawaii	Oklahoma
Illinois	Pennsylvania
Indiana	Rhode Island
Iowa	South Carolina
Kansas	South Dakota
Kentucky	Tennessee
Louisiana	Utah
Maine	West Virginia
Maryland	Wisconsin
Massachusetts	

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

The NRRI then asked staff members at commissions without FACs if their commissions had ever had the adjustment clause and if so, when and why it was abolished? Table 3-4 shows the four commissions that have abolished FACs. Action by the state courts or the state legislature has forced the commissions to abolish the fuel adjustment clause in most cases. The Missouri Commission FAC was abolished in 1979 after the state supreme court ruled that a rate could not be altered when only one component (fuel) changed. The court said that all parts of the rate would

TABLE 3-4

COMMISSIONS THAT HAVE ABOLISHED FACs

Missouri
Oregon
Texas
Vermont

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

have to be reviewed before the Commission could change rates. The Vermont Board's FAC was abolished in 1984, also by court order. The Oregon Commission decided in 1987 that its FAC was no longer needed because the utility did not face major fluctuations in its power costs after making changes in its resource base. The Texas Commission abolished the FAC in 1983 after the state legislature modified the Commission's enabling legislation banning automatic pass-through of changes in fuel or other costs. The Commission uses a fixed fuel factor set during a rate case or a fuel reconciliation proceeding. The utility collects a fixed amount per kilowatthour based on projected fuel and purchased power costs.

The Utah Commission has approved a recommendation to suspend the operation of Utah Power's energy balancing account (EBA) mechanism. In its December 1990 order, the Commission agreed with a proposal from the Utah Division of Public Utilities, Utah Power, and other interested parties. The argument for suspension had three main points: first, PacifiCorp Electric (which merged with Utah Power) has better forecasts than Utah Power, second, the EBA encouraged Utah Power to pass through more expenses than necessary to recover its costs more quickly, and third, the electric utility industry has changed since the EBA's adoption a decade earlier. The suspension began January 1, 1991 and will last at least through December 31, 1992. The EBA will not accrue balances during this time and will not be used to adjust rates. By December 31, 1992, Utah Power must file a plan for determining the costs of its power. If the utility recommends abolishing the EBA as part of that plan, it will have the burden of justifying that proposal to the Commission.[5]

Commission Treatment of FAC Filings

The NRRI asked about commission treatment of electric utility fuel adjustment clause filings. Staff members were asked whether their commissions require the utilities to make periodic filings, how frequently the utilities must file, and what types of data are to be submitted. Staff members were also questioned about their commissions' FAC hearings. The authors asked whether the commissions hold hearings on the FAC filings, whether the commissions must hold hearings at any set frequency, and whether the hearings are public or closed. These questions are discussed in two subsections below. The authors first consider commission requirements on filing and data to be submitted.

Commission Requirements on Filing and Data Submission

As mentioned above, the authors asked the staff members a three-part question on their commissions' FAC filing and data submission requirements. This question was intended to provide some insights into the extent of commission oversight of electric utilities in the FAC by showing how much data the commissions require and how often they want the utilities to furnish it. Table 3-5 shows the responses. Thirty-nine commissions are listed in the table including Georgia, Iowa, and Maryland that do not mandate filing but still require data to be submitted at certain times. In short, the vast majority of commissions require data to be submitted

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[5] In the Matter of the Investigation into the Reasonableness of Allocation and the Rates and Charges for Utah Power & Light Company, PacifiCorp Electric Operations: Phase I Rate Proceeding, Docket No. 90-035-06, Issued December 7, 1990.

TABLE 3-5

COMMISSIONS REQUIRING ELECTRIC UTILITIES
TO MAKE PERIODIC FAC FILINGS

Commission	Frequency of Filing	Data Required To Be Filed
Alaska	Quarterly for some, variable for others	Copies of fuel and purchased power invoices, schedules of kWh sales, balancing account activity summary, data projections for the next quarter, generation data.
Arizona	Monthly	Sales in kWh and dollars by customer class, numbers of customers, bank balance brought forward from previous month, cost of purchased or generated power, fuel adjustment per kWh and amount recovered by fuel adjustment.
Arkansas	Monthly	Source, related cost and amount of fuel, capacity factors, purchased power.
California	Annually	Forecast of energy requirement and revenue requirement associated with fuel and purchased power budget; production cost model that develops resource mix; Incremental Energy Rate based on qualifying facilities cogeneration in and out; reasonableness review of a post 12-month period.
Colorado	Monthly	Copies of detail ledger, transfer vouchers, invoices for power purchases, burn records on fossil units.
Connecticut	Monthly	Fuel costs, total customer monthly MWh use (retail sales by class--residential, commercial, etc.) short-term unit capacity transactions including purchases and sales, prior period adjustments, monthly forecasted sales, fossil fuel costs, monthly forecasted requirements, heat rate.

TABLE 3-5--Continued

Commission	Frequency of Filings	Data Required To Be Filed
Delaware	Annually	Supporting data for twelve months forecasted fuel costs, actual historical data for most recent twelve-month period.
District of Columbia	Monthly	Schedules of costs and sales supporting the FAC rates submitted for approval.
Florida	Monthly and Semiannually	Fuel costs, generation mix, unit capacity and dispatch, fuel burned by type and volume.
Georgia	Not required to file periodically	Forecast sales, unit fuel cost, generation mix, fuel sources.
Hawaii	Upon increase or decrease in cost of fuel	Base rate from last rate proceeding, previous fuel adjustment cost applied to all bills, present cost adjustment, changes in cost of fuel or purchased energy adjusted for changes in revenue taxes, differences between forecasted mix of fuel and purchased energy and the recorded mix.
Illinois	Monthly	Forecasted net allowable energy costs, Illinois allocation, costs included in base rates, generation costs broken down by fuel type (coal, nuclear, etc.) nonrecoverable costs (interchange), sales broken down by customer class.
Indiana	Quarterly	Actual and estimated cost of fuel for reconciliation months, estimated kWh sales and fuel costs for estimation months.
Iowa	Not required to file unless the utility changes the energy adjustment	Estimated expense for energy in month during which adjustment will be used, estimated energy expense for prior month, estimated energy to be

TABLE 3-5-Continued

Commission	Frequency of Filings	Data Required To Be Filed
		consumed under established rates in the month during which energy adjustment will be used, cost of fossil and nuclear fuel, steam and water for hydraulic generation.
Kansas	Monthly	Cost and amount of fuel and purchased power, net interchange, associated kWh, line loss, heat rate, fuel mix and percentage of spot fuel purchased.
Kentucky	Monthly	Fuel cost, transportation cost, inventory; coal deliveries, tons, vendor, specifications; power plant performance data, off-system power purchases and sales.
Louisiana	Monthly	Invoices, accounting ledgers.
Maine	Annual FAC filings plus monthly reports	Annual filings: projected fuel cost (fuel, purchased power, off-system sales), computation of reconciliation adjustment including carrying charges; Annual report: fuel procurement policies, planning, operation; Monthly reports: data needed to calculate and document fuel charges and costs.
Maryland	Not required to file unless fuel costs vary by plus or minus 5 percent	Generation, fuel mix, fuel costs, productive capacity, purchasing practices.
Massachusetts	Quarterly	Invoices for purchased power, reconciliation from previous quarter (over/undercollection), calculation of current fuel adjustment charge, calculation of small power producer rates, proof of least-cost fuel purchasing, cost of fuel, conservation and load management expenses (for

TABLE 3-5--Continued

Commission	Frequency of Filings	Data Required To Be Filed
		Boston Edison: documentation of Pilgrim Plant performance).
Michigan	Annually	Comprehensive description of sources of fuel and purchased power.
Minnesota	Monthly	Fuel cost, kWh sales, calculations.
Nevada	Annually	Summary of monthly activity in the account, detail of monthly energy cost by generating unit and type of fuel, monthly purchased power cost, projected fuel costs for the next twelve-month period.
New Hampshire	Monthly & Semiannually	Projected fuel costs, projected kWh sales; reconciliations of prior periods; projected plant dispatch, output, and costs; planned outages; plant performance data for incentives and penalties, explanations of unplanned outages.
New Jersey	Annually	Actual fuel costs for preceding period, fuel forecasts for upcoming period, plant running rates--actual and projected, previous period over/underrecovery balance with interest calculation.
New Mexico	Monthly	Fuel and purchased power costs, interchange and sales for resale fuel expense, balancing account, kWh sales.
New York	Monthly	Schedules and service classifications to which filing applies, base cost of fuel, present average cost of fuel to the utility, point of delivery, present average cost to the utility, date at which and period for which the average

TABLE 3-5--Continued

Commission	Frequency of Filings	Data Required To Be Filed
		was determined, amount per unit of consumption affected, date when the increase or decrease in rates becomes effective and the period it will be in effect.
North Carolina	Annually	Actual test period kWh sales, fuel related revenues, fuel related expenses for utility's total system and for its North Carolina retail operations, test period kWh sales normalized for weather, customer growth, and usage, adjusted test period kWh generation corresponding to normalized test period kWh usage, cost of fuel corresponding to the adjusted test period kWh generation including detailed explanation of how the cost was derived, monthly fuel report and monthly base load power plant performance report for last month in the test period, work papers supporting calculations, nuclear capacity ratings from the last case.
North Dakota	Monthly	Work papers.
Ohio	Monthly, Semiannually, and Annually	Monthly: summaries of all fuel and power transactions and generation/ sales, etc.; Semiannually: special summary subset of above filings plus information to show fuel costs to be fair, just, reasonable, testimony; Annually: annual summary of the monthly filings plus responses to additional questions.
Oklahoma	Monthly	Information needed to verify the calculation.

TABLE 3-5--Continued

Commission	Frequency of Filings	Data Required To Be Filed
Pennsylvania	Quarterly & Annually	Projected (annual filing) and actual (quarterly filing) monthly data on cost by fuel type (data by station or unit for nuclear), megawatt purchases and sales of bulk power including purchases from any nonutility generator with 10 MW or larger capacity; demand and energy component breakdown of power sales and purchases sometimes provided.
Rhode Island	Every 3 or 4 months, depending on utility involved	Actual fuel cost data for previous FAC period, sources of generation, type of fuel, comparative data with other utilities, projected generation mix, prices projected for oil, coal, gas, actual/projected purchases and bulk sales.
South Carolina	Semiannually	Fuel stock report (description, beginning inventory, receipts, issues, ending inventory, etc.), received coal-cost/ton by plant, total receipts, quality (Btu, SO_2, ash), burned cost, total cost of fuel (fossil, nuclear, purchased power, interchange power, fuel cost recovered through intersystem sales), power plant performance data, outage reports, generation mix statistics (generation by plant, kWh per month), MWh sales, fuel cost, Licensee Event Reports (for utilities with nuclear plants).
Tennessee	Monthly	Cost of power of the supplier.
Utah	Monthly	Fuel cost, purchased power costs (offset by surplus sales revenues and interruptible revenues), kWh sales, QF energy.

TABLE 3-5--Continued

Commission	Frequency of Filings	Data Required To Be Filed
Virginia	When utility wants to change the fuel factor	Load curves, unit availability and heat rates, purchased power projections and cost, heat contents of fuels, dispatch lambda.
West Virginia	Annually	Actual historic numbers for the period under review, projections for the upcoming hearings.
Wisconsin	Annually	Utility's economic dispatch, amount of fuel used, fuel inventory, estimated cost of fuel per plant, coal contracts.

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

on a regular basis. This would appear to be an important finding indicating that the commissions are trying to oversee the utilities through the fuel adjustment clause.

Regarding the frequency of FAC filings, commissions require the electric utilities to make filings annually, semiannually, quarterly, or monthly. Several commissions use other criteria instead of a set time schedule. Monthly filings are the most common with twenty commissions having this requirement. Those commissions are Arizona, Arkansas, Colorado, Connecticut, the District of Columbia, Florida, Illinois, Kansas, Kentucky, Louisiana, Maine, Minnesota, New Hampshire, New Mexico, New York, North Dakota, Ohio, Oklahoma, Tennessee, and Utah. Eleven commissions have an annual filing requirement. Those commissions are California, Delaware, Maine, Michigan, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, West Virginia, and Wisconsin. Five commissions, Alaska, Indiana, Massachusetts, Pennsylvania, and Rhode Island, have a quarterly filing requirement. Four commissions, Florida, New Hampshire, Ohio, and South Carolina, have a semiannual filing requirement.

Five commissions, Alaska, Hawaii, Iowa, Maryland, and Virginia, require the utility to file on some basis other than a regular fixed schedule. Usually the utility must file when the cost of its fuel changes. In Alaska, smaller utilities without balancing accounts file whenever their fuel cost changes. These utilities use only one type of fuel, diesel, and the cost may change as frequently as once a month or as seldom as less than once a year. The Hawaii Commission requires filings whenever the cost of fuel increases or decreases. Iowa utilities must file when they change the energy adjustment while the Maryland utility must file when its fuel costs increase or decrease by 5 percent. Virginia electric utilities must file when they want to change the fuel factor used in the fuel adjustment. At the end of the year, each utility projects its costs for the upcoming year. However, the utility does not submit a formal FAC filing to the Virginia Commission unless it wants to change the fuel factor used in the adjustment. If the factor is working well enough to recover its costs, the utility may not file for two or three years.

Some commissions fall into more than one of the above categories because they may have different filing requirements for different electric utilities, or they may have multiple filing requirements for the same utility during the course of the year. An example of the former is the Alaska Commission, which requires the larger utilities (those with balancing accounts) to file quarterly while requiring smaller utilities to file when their fuel costs change. Another example is the Rhode Island Commission which, as shown above, mandates quarterly filings and also requires filings every four months, depending on the utility. Examples of commissions with multiple filing requirements during the course of a year are Florida with monthly and semiannual filings, Maine with monthly and annual filings, and Ohio with monthly, semiannual, and annual filings.

Table 3-5 also lists the types of data that the utilities are to submit in their FAC filings. The basic types of data that are required by many of the commissions include sales in kilowatthours, fuel and purchased power invoices, the actual cost of fuel for the previous adjustment period, the estimated cost of fuel for the next adjustment period, the amount of purchased power, generation costs and mix, the reconciliation (over- or underrecovery of costs) from the previous period, power plant performance data, and data on outages. Commissions also might want utilities to submit data on fuel heat rates, fuel inventories, coal contracts, nuclear power plants, and purchases from qualifying facilities and nonutility generators.

The commissions vary by the amount of and the types of data they want utilities to submit in their FAC filings. Some require some minimal basic amount while others require additional information. An example of the former is the Arkansas Commission, which wants its jurisdictional utilities to submit data on the source, cost, and amount of fuel plus capacity factors and purchased power. Likewise, the District of Columbia Commission requires the schedules of costs and sales that form the basis of the submitted FAC rates. An example of a commission that wants more information is the South Carolina Commission whose data requirements include fuel stock reports (beginning inventory, receipts, issues, ending inventory), cost per ton of coal received by the utility, total receipts of coal, quality of coal (Btu content, SO_2 content, ash), total cost of fuel (fossil, nuclear, purchased power, interchange power, fuel cost recovered through intersystem sales), power plant performance data, outage reports, generation mix statistics (generation by plant, kilowatthours per month), and sales in megawatt-hours.

The commissions may also require different types of data to be submitted in different filings. In Maine, the utilities submit annual filings plus monthly reports. In the annual filings, the data include the projected fuel cost (fuel, purchased power, off-system sales), and the computation of the reconciliation adjustment including carrying charges. In the monthly reports, the utility must submit data needed to calculate and document the fuel charges and costs. The utility must also submit an annual report setting out its fuel procurement policies, planning, and operations. The Ohio Commission requires monthly, semiannual, and annual filings. In the monthly filings, the utility submits summaries of all fuel and power transactions and generations, sales and so on. In the semiannual filings, the utility includes summaries of the monthly filings plus any information needed to prove that its fuel costs are just and reasonable. In the annual filing, the utility includes a summary of the monthly filings plus responses to any additional questions that the Commission might have asked.

Commission Hearing Procedures

As mentioned above, the NRRI asked the staff members several questions about their commissions' FAC hearing procedures. As with the just-discussed topics of frequencies of data filings and amount of required data, the questions on hearing procedures are intended to provide some indication of how actively the commissions are overseeing the utilities in the FAC process. Of course, the fact that a commission is holding hearings does not necessarily mean that active, meaningful oversight is occurring. And the fact that a commission is not holding hearings does not necessarily mean that oversight is not being conducted. Hearings, however, should provide some gauge as to what the commissions are doing and how actively they are doing it.

The authors asked the staff members whether their commissions hold hearings on the utilities' FAC filings and whether hearings are held on every or only on certain filings. Table 3-6 shows the twenty-nine commissions that hold hearings on utility FAC filings. Seventeen have hearings on every filing and twelve conduct such proceedings only on certain filings. Two-thirds of the forty-two commissions that have fuel adjustment clauses (as listed in Table 3-1) hold hearings on the filings.[6] Thus, hearings are a fairly common part of the FAC procedure although not universal. Comments on specific commissions follow.

The commissions that hold hearings on every FAC filing are discussed first. A few of them provided additional explanation. The Georgia Commission generally holds hearings. In some instances, stipulation agreements have been reached among the involved parties. The New Hampshire Commission conducts hearings on every

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[6] The Virginia Commission is listed in Table 3-6 as having hearings on every FAC filing, but is not listed as having FACs in Table 3-1. The Commission responded that Virginia has a projected fuel factor rather than a fuel adjustment clause and that hearings are held on every filing. Thus, twenty-eight of the forty-two commissions listed in Table 3-1--or two-thirds--are also listed in Table 3-6.

TABLE 3-6

COMMISSIONS THAT HOLD HEARINGS ON FAC FILINGS

Hearings Held On Every Filing	Hearings Held Only On Certain Filings
California	Colorado
Connecticut	Illinois
Delaware	Indiana
Florida	Kentucky
Georgia	Maine
Louisiana	New Jersey
Maryland	New York
Massachusetts	Ohio
Michigan	Oklahoma
Mississippi	Pennsylvania
Nevada	Utah
New Hampshire	Wisconsin
North Carolina	
Rhode Island	
South Carolina	
Virginia	
West Virginia	
(N=17)	(N=12)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

filing of jurisdictional utilities except those of municipal utilities. The municipal utilities file monthly while other utilities file semiannually. In Mississippi, the utilities do not change their fuel adjustments often but the Commission will hold a hearing when a utility files for a change. Many issues are resolved in prehearing conferences although hearings may be needed to settle any remaining disputes. The Virginia

Commission tries to provide opportunities for interested parties to express their views on any proposed changes in the fuel factor.

Commissions holding hearings on certain filings may conduct proceedings if a dispute arises between involved parties and it cannot be resolved or if a new or unusual circumstance needs to be considered. The Utah and Pennsylvania Commissions are examples of regulatory bodies holding hearings for these reasons. Hearings may also be held on a set schedule, such as annually, that differs from the utilities' filing schedule. The Colorado and Illinois Commissions, which conduct annual review hearings, are examples; the Ohio Commission, which conducts hearings every six months to consider filings and any additional information, is another. Other commissions use different criteria than those already mentioned in deciding whether or not to have hearings on FAC filings. For example, in Indiana the distinction between generating and nongenerating electric utilities is important in determining whether or not to hold hearings. The Commission holds hearings on the FACs of utilities that generate their own power. Nongenerating utilities file monthly or quarterly. Those filings are shorter than the generating utilities' and contain the fuel cost factor of the utility or utilities from which the power was purchased, the base cost of fuel, and any line loss. The amount of any increase in FAC rates is important in determining whether to conduct hearings at the Wisconsin Commission. Hearings are held annually at the Commission and there are also shorter proceedings to consider increases in FAC costs of more than 3 percent. There are no hearings for decreases in costs if a stipulation is reached.

The Kentucky Commission's regulations specify hearings every six months to consider past fuel adjustments. In addition, the Commission reviews each FAC's operation in a hearing two years after the effective date of the clause.[7] In Maine, hearings on the utility's annual adjustment may be required. Often, a stipulation agreement is reached by the parties involved. The New Jersey Board schedules hearings for every FAC filing. If there are no disputed issues, however, the matter may be settled before the hearings are held and a stipulation signed. The Oklahoma

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[7] 807 KAR 5:056 Fuel adjustment clause, Section 1, paragraphs 11 and 12 (1982).

Commission verifies filings in a general fuel audit. Problems are resolved during the general fuel hearing.

New York regulations require an electric utility that wants to begin or continue to use a fuel adjustment clause to prove that its fuel costs vary to such an extent that they cannot be reasonably estimated in rate proceedings. The utility also must prove that these costs make up a large portion of its cost of service. (Note that these are two of the three traditional tests.) The Commission must hold hearings to oversee utility compliance with the FAC regulations at least once every four years. Consideration of FAC compliance in a rate case proceeding would satisfy this hearing requirement.[8]

Some of the commissions (Arizona, Minnesota, and North Dakota) responding that they did not hold hearings on FAC filings said that hearings were held in rate case proceedings instead. The Kansas Commission does not hold FAC hearings unless problems arise with a particular filing. At the FERC, periodic FAC filings are not required. Fuel costs may be considered in rate cases or in complaint proceedings. The Commission would hold the latter type of hearing if a wholesale customer disputed an expense that had been passed through the FAC or if findings from an audit or an investigation needed to be considered.

The NRRI asked the staff members whether their commissions are required to hold FAC hearings at any set frequency. Table 3-7 shows the twenty-three commissions that responded that they are. Annual and semiannual hearings are the most frequently required types. Nine commissions are required to hold hearings annually and eight must hold semiannual hearings. The commissions holding annual hearings are California, Colorado, Illinois, Maine, Michigan, Nevada, North Carolina, West Virginia, and Wisconsin. The commissions holding semiannual hearings are Florida, Kentucky, Maryland, New Hampshire, Ohio, Oklahoma, South Carolina, and Utah. Three commissions, Connecticut, Louisiana, and New Hampshire, hold monthly hearings. Two commissions, Indiana and Massachusetts, hold hearings quarterly. The New York and North Dakota Commissions must hold hearings at least once every

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[8] Title 16 NYCRR, Paragraph 136.57 (1985).

TABLE 3-7

COMMISSIONS REQUIRED TO HOLD FAC HEARINGS AT A SET FREQUENCY

Commission	Frequency With Which Hearings Must Be Held
California	Annually
Colorado	Annually
Connecticut	Monthly
Florida	Semiannually (each February and August)
Illinois	Annually
Indiana	Quarterly
Kentucky	Semiannually and every two years
Louisiana	Monthly
Maine	Annually
Maryland	Semiannually
Massachusetts	Quarterly
Michigan	Annually
Nevada	Annually
New Hampshire	Monthly and semiannually
New York	At least every four years
North Carolina	Annually
North Dakota	Every four years
Ohio	Semiannually
Oklahoma	Semiannually
South Carolina	Semiannually
Utah	Semiannually
West Virginia	Annually
Wisconsin	Annually

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

four years. The Kentucky Commission, in addition to the semiannual hearings mentioned above, also holds hearings every two years.

A few commissions offered additional explanation of their practices. The Maryland Commission is required to hold FAC hearings every six months for small utilities only. Regularly scheduled hearings are not required for large utilities. As shown in Table 3-5 above, a large utility must file when its fuel costs increase or decrease by 5 percent. The Commission then conducts a hearing. The New York Commission must hold an FAC hearing every four years, but consideration of the fuel adjustment during a rate case would also fulfill this requirement. The Wisconsin Commission's annual FAC hearings are usually conducted along with rate case proceedings.

The NRRI asked staff members whether their commissions' FAC hearings are public or closed. Table 3-8 shows the thirty-seven commissions responding that their hearings are public. None said their hearings are closed. Table 3-8 contains several more commissions than Table 3-6 which listed commissions holding hearings on every or certain FAC filings. Eight commissions, Alabama, Arizona, the FERC, Hawaii, Kansas, Minnesota, New Mexico, and North Dakota, responded that they did not hold FAC hearings and that their FAC hearings are public. Much of this apparent inconsistency can be explained. In many instances, as shown below, the commission considers FAC issues in rate proceedings. In other instances, such as Alabama, Kansas, and New Mexico, hearings are not generally held but the commission may conduct such proceedings if problems arose or modifications to the adjustment were necessary. In short, these commissions do not hold FAC hearings as a general rule but will, if needed, consider FAC matters in proceedings that happen to be public.

The Alabama Commission does not generally hold hearings on FAC filings. A public hearing was held in 1981 when the Energy Cost Recovery Rate (ECR) was adopted. The ECR is modified if the Commission or Alabama Power or both feel that such action is necessary based on the over- or underrecoveries under the current rate. If any hearings were necessary, they would be public. The Arizona Commission holds hearings for rate cases and not usually for fuel adjustment filings. These hearings are open to the public. The Commission also holds regular public meetings

TABLE 3-8

COMMISSIONS WITH PUBLIC FAC HEARINGS

Alabama	Minnesota
Arizona	Mississippi
California	Nevada
Colorado	New Hampshire
Connecticut	New Jersey
Delaware	New Mexico
FERC	New York
Florida	North Carolina
Georgia	North Dakota
Hawaii	Ohio
Illinois	Oklahoma
Indiana	Pennsylvania
Kansas	Rhode Island
Kentucky	South Carolina
Louisiana	Utah
Maine	Virginia
Maryland	West Virginia
Massachusetts	Wisconsin
Michigan	

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

to act on proposed orders. The FERC does not require electric utilities to file periodic fuel adjustments. Fuel costs may be considered in a rate case or in a complaint proceeding. In the latter proceeding, the Commission would schedule a hearing if a customer of the utility disputed an expense passed through the FAC or if an audit or investigation of the utility resulted in a discovery that needed to be considered. In Hawaii, the fuel adjustment rate formula is established in a rate case. Any subsequent modifications would also be made in the course of rate case proceedings, which are public. The Kansas Commission holds FAC hearings only when problems arise with particular filings. The Minnesota Commission has the authority to hold FAC hearings but has not needed to conduct such proceedings. Fuel adjustments are sometimes considered in rate cases. The New Mexico Commission does not hold FAC hearings unless a party challenges a filing. In such an instance, the case would be docketed and a public proceeding undertaken. The North Dakota Commission's rules specify that a hearing must be held every four years to evaluate utility operations and purchases. This hearing is usually part of a rate proceeding.

The authors asked the staff members whether purchased power contracts that may be considered during the FAC hearings were given confidential protection by their commissions. This question was intended to determine the extent to which commissions might be facing and responding to some important conflicting pressures. On the one hand, the ratepaying public would want commission meetings to be open so that their access to the commission would not be impaired. On the other hand, the utility would want certain information to be considered proprietary and thus limit public access by giving confidential protection to such information. In some instances, information may need to be kept confidential so that the utility can operate more efficiently. Table 3-9 shows the ten commissions that give confidential protection to the purchased power contracts. At three of the ten commissions, Ohio, West Virginia, and Wisconsin, confidentiality is provided only if requested by the utility. The low number of regulators granting confidentiality would indicate either that the commissions are not facing the conflicting viewpoints described above (possibly because the issue has not arisen) or that they have decided to take the ratepayers' side and provide open access to the regulatory process. Comments on specific commissions follow.

The California Commission usually gives such protection to the terms and prices of the purchased power contracts. In Maine, some pricing terms may be protected. In Nevada, confidentiality may or may not be granted. Any part of the hearing that is recorded would be public. In Ohio, confidentiality would be given if the utility made a request for such protection. The Commission generally grants such requests for contracts. The West Virginia Commission does not give confidential protection to the contracts unless the utility requests it. The Commission must then

TABLE 3-9

COMMISSIONS THAT GIVE CONFIDENTIAL TREATMENT TO PURCHASED POWER CONTRACTS CONSIDERED DURING FAC HEARINGS

California	Nevada
Colorado	North Carolina
Delaware	Ohio
Kansas	West Virginia
Maine	Wisconsin

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

issue a protective order. The Wisconsin Commission also gives confidential protection if the utility makes the request and qualifies under Commission rules. Other parties can challenge the request, however. Occasionally, contracts are reviewed at the utility's offices. In addition to these commissions that do or may grant confidentiality, the Oklahoma Commission gives confidential protection to generation fuel documents. Purchased power contracts are not considered proprietary, however, and thus not confidential.

FAC Treatment of Costs

The authors asked about the costs allowed in the fuel adjustment clause, the pass-through of demand and energy components, and the treatment of cost increases and decreases. The inclusion and pass-through of various costs in the FAC and the treatment of cost increases and decreases are important issues in the consideration of automatic adjustment clauses in general and the FAC in particular because they probe the scope of the FAC cost recovery and what is done when the costs fluctuate. In asking about the costs allowed in the FAC, the authors listed three major types: fossil fuel costs, nuclear fuel costs, and administrative costs associated with fuel procurement. Respondents could also list other costs allowed into the adjustment.

Table 3-10 shows the commissions allowing into the FAC these types of costs. As seen in the table, the pass-through of fossil fuel expenses is widespread with forty-one commissions allowing these costs in the FAC. Nuclear fuel cost recovery is not quite as common although a majority of the commissions--thirty-three--also allow this type of expense to be passed on. This difference may be due to the fact that not all electric utilities own or operate nuclear power plants or depend on such plants for their power. The pass-through of administrative costs associated with fuel procurement is allowed by only eight commissions. This cost is presumably recovered in rate cases instead.

Table 3-11 shows the thirty-three commissions allowing other types of costs into the FAC. A variety of costs are allowed, including fuel transportation, interest expense, wheeling expense, fuel oil carrying cost, labor costs, the cost of operating an oil pipeline, the cost of operating a train for carrying coal, and steam and hydro generation. The cost listed most frequently is purchased power. With respect to that particular expense, some commissions allow only the energy portion to be passed through the FAC. Some respondents also said that purchased power was allowed only if bought on an economic dispatch basis.

The authors asked the staff members whether their commissions allow the energy and the demand components of purchased power to be passed through in the FAC. Table 3-12 shows the commissions allowing these components. Energy is considered by the commissions to be the more justified expense in terms of FAC recovery as forty-one commissions allow the energy portion while twenty-three allow the demand. With respect to the energy component, some commissions, such as North Carolina, allow only the fuel cost portion to be recovered through the FAC. Ten of the twenty-three commissions allowing recovery of the demand component attach special conditions or criteria that have to be met before those costs can be passed on. For example, the transaction must have been an economy purchase, a purchase from a qualifying facility or other alternative power producer, or the utility seeking to recover the cost in the FAC must be a cooperative or a small utility.

TABLE 3-10

COMMISSIONS ALLOWING VARIOUS TYPES OF MAJOR COSTS IN THE FAC

Cost	Commissions Allowing Cost in the FAC
Fossil Fuel Costs	Alabama, Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, FERC, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Nevada, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, South Dakota, Tennessee, Utah, Virginia, West Virginia, Wisconsin (N=41)
Nuclear Fuel Costs	Alabama, Arizona, Arkansas, California, Connecticut, Delaware, FERC, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, South Dakota, Virginia, Wisconsin (N=33)
Administrative Costs Associated With Fuel Procurement	Arizona, California, Connecticut, Florida, Georgia, Indiana, Pennsylvania, Utah (N=8)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

TABLE 3-11

OTHER COSTS ALLOWED BY COMMISSIONS IN THE FAC

Commission	Other Costs Allowed in the FAC
Alaska	Purchased power, interest expense.
Arkansas	Freight (transportation) associated with coal.
California	Capacity, wheeling expense, purchased power, fuel oil carrying cost, gas storage cost, nuclear fuel disposal cost, fuel oil demand charge (Chevron), coal inventory carrying cost.
Colorado	Firm and nonfirm purchased power, IPPF purchases, interchange power, wheeling.
Connecticut	Labor costs.
Delaware	Net energy cost of energy purchases inclusive of capacity or demand charges when such energy is purchased on economic dispatch basis.
District of Columbia	Cost of operating an oil pipeline from the point of off-loading to two generating stations, cost of operating two-unit trains for transporting coal.
FERC	Energy portion of purchased power if purchased on economic dispatch basis, other purchased power costs including energy and demand components.
Florida	Oil backout costs, conservation costs, generation performance incentive factor.
Georgia	Transportation.
Hawaii	Energy portion of purchased energy cost.
Indiana	Steam generation, hydro generation.
Iowa	Energy costs for purchased energy.

TABLE 3-11--Continued

Commission	Other Costs Allowed in the FAC
Kansas	Purchased power costs, net interchange.
Kentucky	Transportation as listed in Account 151 of FERC Uniform System of Accounts.
Louisiana	Transportation costs, taxes.
Maine	Purchased power costs (except capacity portion if separately stated).
Maryland	Energy component of power purchases.
Massachusetts	Purchased power.
Michigan	Purchased power, natural gas.
Minnesota	Purchased power.
Mississippi	Transportation charges, excise taxes, maintenance and depreciation of utility-owned transportation equipment, purchased power (net energy cost when purchased on economic dispatch basis).
Nevada	Purchased power costs (capacity and energy), fuel handling costs, refunds, inventory adjustments.
New Hampshire	Small power producer costs.
New York	Hydropower, economy energy purchases, adjustment or corrections to previous estimates, inventory adjustment, IPP purchases.
North Carolina	Fuel portion of purchased power.
Ohio	Purchased power (fuel portion), system loss (fuel portion), special Ohio coal research & development costs, reconciliation of prior estimated costs.

TABLE 3-11--Continued

Commission	Other Costs Allowed in the FAC
Oklahoma	Refunds and corrections of fuel and power costs.
South Carolina	Purchased power, interchange power.
South Dakota	Purchased power.
Utah	Purchased power costs, surplus sales revenues/interruptible revenues (treated as an offset to fuel and purchased power costs), QF energy costs, geothermal fluids.
West Virginia	Purchased power, PURPA power, profits from off-system sales.
Wisconsin	Transportation cost.

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

TABLE 3-12

COMMISSION TREATMENT OF PURCHASED POWER IN FACs*

Commissions Allowing Energy Component to be Passed Through		Commissions Allowing Demand Component to be Passed Through
Alabama	Massachusetts	Alaska
Alaska	Michigan	Arkansas
Arizona	Minnesota	California
Arkansas	Mississippi	Colorado
California	Nevada	Delaware
Colorado	New Hampshire	District of Columbia
Connecticut	New Jersey	FERC
Delaware	New Mexico	Florida
District of Columbia	New York	Illinois
FERC	North Carolina	Iowa
Florida	North Dakota	Kansas
Georgia	Oklahoma	Maine
Hawaii	Pennsylvania	Maryland
Illinois	Rhode Island	Massachusetts
Iowa	South Carolina	Michigan
Kansas	South Dakota	Nevada
Kentucky	Tennessee	New Jersey
Louisiana	Utah	New Mexico
Maine	Virginia	New York
Maryland	West Virginia	Oklahoma
	Wisconsin	Tennessee
		Virginia
		West Virginia
(N=41)		(N=23)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

*Some commissions allow both energy and demand components to be passed through and are listed in both columns.

Some of the commissions not passing through the demand charges in the FAC provide for the recovery of such charges in base rates. All of the commissions that allow the demand component also allow the energy component to be passed through. In short, eighteen commissions permit only the energy expense to be passed through and twenty-three permit both the energy and the demand portions.

Commissions that allow both demand and energy to be passed through are considered first. In Alaska, the cost of the purchased power may be flowed through a balancing account and then spread over the utility's sales. In California, the amount and cost of purchased power is projected every twelve months to set the rates for the FAC for the upcoming period. The utility purchases power and capacity, and these costs are entered into its balancing account. A reasonableness review is then held during which the costs from the balancing account are compared with the utility's avoided costs to determine whether or not the price that the utility paid for the power and the capacity was greater than the costs of its own generation. Excess costs may be disallowed by the Commission. In Colorado, the monthly cost of power is calculated and compared to the cost that was entered into the base rates from the latest rate case. Any amount greater or less than the last base rate is then factored into the monthly FAC calculations. In the District of Columbia, the electric utility purchases power through the Pennsylvania-New Jersey-Maryland Interchange and in other transactions. The purchases and sales are recorded and factored into the FAC, subject to Commission audit.

The Florida Commission allows prudent and reasonable purchased power costs to be passed through every six months. The Nevada Commission, based upon its legal department's interpretation of the appropriate statutes, allows all purchased power costs to be recovered. In Oklahoma, the cost of purchased power, as invoiced, is passed through the FAC of each regulated electric utility. The Tennessee Commission allows both demand and energy components to be passed through. The Commission, however, only regulates one small electric utility that does not generate its own power. The fuel cost charges of this utility's power supplier constitute the sole basis of the FAC.

In West Virginia, allocation among the customer classes of the demand and energy costs that are passed through is based on cost of service factors and line loss studies. These factors and studies have to be approved by the West Virginia Commission.

Some commissions allow the energy component to be passed through automatically but allow demand to be recovered only under certain conditions or for certain utilities. For example, the Kansas Commission allows the energy component to be passed through. Electric cooperatives may recover the demand costs through the FAC, but investor-owned utilities are not allowed to pass through the demand component of purchased power. The FERC allows the demand charges to be recovered only to the extent that the power purchases are not required to maintain the utility's system reliability. The Iowa Board's regulations also allow energy costs to be passed through. The demand component may or may not be allowed through, depending on whether the utility owns its generation capacity.[9] In the past, the Maryland Commission has allowed large utilities (those with gross annual revenues of at least $25 million) to recover the demand component through the FAC. The Commission more recently decided that those utilities will have to recover demand costs in base rates. The Commission still allows the small utilities to pass through energy and demand costs in the FAC.

The Delaware Commission allows demand charges to be passed through only when the energy is purchased on an economic dispatch basis. The Maine Commission allows FAC recovery of demand charges only for power purchased from qualifying facilities. The Commission must find these charges to be just and reasonable. The Illinois and Virginia Commissions allow the demand charges from economy purchases to be passed through. The New Jersey Board allows FAC recovery of the demand charges from utility contracts with alternative power producers. In the case of power purchases from other utilities, however, the capacity charges are recovered in base rates. Energy charges from both the alternative power producers and other utilities are passed through the FAC. In New York, the energy component is passed through

[9] Iowa Administrative Code, Chapter 20: Utilities, 199-20.9(476) (October 8, 1986).

but recovery of the demand component varies. If the power is purchased through a firm contract, the capacity charge is recovered through base rates. If the power is purchased in an economy transaction, both energy and demand costs are recovered through the FAC because such transactions are priced at less than the utility's avoided costs. If the transaction is an emergency or supplemental purchase, all costs up to the utility's avoided costs are recovered through the FAC. The capacity portion of the emergency or supplemental purchase would be estimated and then recovered through base rates.

Commissions that allow the energy component to be passed through the FAC but do not allow the demand component to be recovered are considered next. In Connecticut, the cost of fossil fuel is a component of rates as set in a rate case. Differences in the cost of the fuel from the level set in the rate case are recovered through the FAC. A credit is passed on to customers if the price of fuel falls and a charge is levied if the price rises. The Georgia Commission does not allow the demand component to be passed through except in the case of Savannah Electric which is participating in the Southern Company Pool. The demand charges resulting from the equalization of the capacity of the Pool's member companies are recovered in the FAC to the extent that they are related to expected savings in fuel costs. The Hawaii Commission's regulations provide that the FAC is to cover only increases or decreases in the unit cost of fuel and purchased energy.[10] The Kentucky Commission's regulations[11] and the Mississippi Commission's regulations specifically exclude recovery of capacity or demand charges in the case of economic dispatch purchases. The Minnesota Commission allows for FAC recovery of fuel and purchased power costs only.

The North Carolina Commission allows the fuel portion of the energy component to be passed through the FAC. The demand charges are not passed through. The Rhode Island Commission has a similar policy. The FAC covers only the fuel costs. The costs of purchased power are handled in a separate purchased

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[10] Title 6, Chapter 60, Administrative Rules, Section 6-60-6 (1981).

[11] 807 KAR 5:056, Fuel Adjustment Clause, Paragraph 3(a-e) (1982).

power adjustment clause or a capacity cost adjustment clause. These latter adjustments cover both demand and energy. In New Hampshire, purchased power costs are passed through a purchased power clause adjusted semiannually. Any power costs recovered in base rates are subtracted from this adjustment. In Pennsylvania, demand costs are recovered in base rates. The South Carolina Commission allows the recovery of purchased power fuel costs when those charges are set forth on the billing statement. Interutility power purchases are covered in the FAC when the energy is purchased on an economic dispatch basis. In South Dakota, the demand component is not passed through if the power is purchased in an economic dispatch transaction. The South Dakota Commission allows for the recovery in base rates of the demand charges from long-term power transactions. The Wisconsin Commission allows the recovery of energy charges only when the transaction is a short-term (less than one year) economy purchase. Demand charges from these purchases are not recovered. In longer-term contracts of more than one year's duration, neither energy nor demand are recovered in the FAC.

A few commissions, such as Wisconsin (for longer-term contracts), allow neither energy nor demand to be passed through the FAC. Indiana is another example. The Ohio Commission usually allows neither energy nor demand to be recovered in the FAC. An exception to this general rule is any economic purchase in which the fuel charges plus the other energy and demand costs are less than the utility's incremental fuel cost. In this instance, the entire amount would be passed through the FAC. Cogeneration is another exception to the Commission's general approach. Only a few cases have involved cogeneration but the staff feels that the Commission will allow both energy and demand charges from an approved cogeneration facility to be recovered through the FAC.

The authors asked the staff members whether their commissions' FAC procedures treat cost decreases any differently than cost increases and whether fuel cost decreases are passed through to customers as quickly as cost increases. The staff members were nearly unanimous in replying that cost decreases are not treated any differently and that cost decreases are passed on as quickly. Comments on specific commissions follow.

Only three commissions, Georgia, Pennsylvania, and Wisconsin, responded differently from the general pattern noted above, and these are discussed first. In Georgia, cost decreases are not passed through as quickly. In Pennsylvania, cost decreases are passed on to ratepayers more quickly and cost increases are passed through slowly. Cost increases are covered in the next period's FAC while decreases are factored into the FAC immediately. In Wisconsin, cost decreases are treated differently as no hearing is required to consider them.

Commissions that do not treat cost decreases any differently include Alabama. The same FAC factor is applied to all customer classes by the Commission. In Nevada, cost increases caused by a major event such as settlement of arbitration would be factored into the adjustment over a three year period while any refunds would be passed through to ratepayers immediately. The Ohio Commission expresses concern over any cost increases and examines them more thoroughly in hearings. However, there is no major difference in Commission treatment of cost increases and decreases. In Oklahoma, fuel cost increases and decreases are passed through the FAC every month. New Mexico Commission regulations provide for the flow-through to customers of any increases and decreases in the costs per kilowatthour of electricity.[12] A balancing account is used to cover any over- or undercollections of revenues by automatically increasing or decreasing the fuel adjustment for the following month.

Accounting Procedures, True-Up, and Treatment of Overcharges

The authors included several questions about required accounting procedures, use of true-up procedures, and commission treatment in the FAC of overcharges. The previous section's discussion of costs and changes in costs deals with a topic central to any consideration of automatic adjustment clauses. However, the authors felt that it was also important to learn about some of the factors, such as accounting

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[12] NMPSC Rule 550: Fuel and Purchased Power Cost Adjustment Clauses for Electric Utilities; 550.2: Intent, 550.8(b): Information to be Filed (1988).

and true-up procedures, leading up to the FAC filings and other important parts of the FAC process such as the treatment of overcharges.

Required Accounting Practices

The NRRI asked the staff members whether their commissions require electric utilities to use any particular accounting practices. Table 3-13 shows the twenty-six commissions responding that they have such a requirement. Twelve of these commissions mandate the use of the FERC Uniform System of Accounts. Those commissions are Delaware, the District of Columbia, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Nevada, Ohio, Oklahoma, and South Carolina. (Two other commissions not listed in Table 3-13, South Dakota and West Virginia, responded that they do not require accounting procedures but their jurisdictional electric utilities are using the FERC system.) The Tennessee Commission requires the use of the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts. Three other commissions listed in Table 3-13, California, Iowa, and Virginia answered that they require the Uniform System of Accounts without specifying the FERC system or the NARUC system. In short, sixteen of the twenty-six commissions in Table 3-13 require the use of the FERC or the NARUC Uniform System of Accounts with the FERC system more preferred.

Comments on specific commissions follow. The Arizona Commission requires each utility to file an annual report by April 1. In Connecticut, each utility uses its own accounting formula. The Illinois Commission requires utilities to use any of three methods: as billed, deferred cost, or unbilled revenue. In Kentucky, fuel costs are based on the weighted average cost of the fuel inventory. The Wisconsin Commission also bases costs on the inventory. Utilities must file monthly reports to the Commission. The New Hampshire Commission requires deferred accounting to match fuel costs with the utility's power sales. The North Dakota Commission uses a four-month moving average which also includes a provision for handling over- or underrecoveries of costs. The Oklahoma Commission, as noted above, has adopted the FERC System of Accounts. In addition, the Commission has adopted the

TABLE 3-13

COMMISSIONS THAT REQUIRE THE ELECTRIC UTILITY TO USE PARTICULAR ACCOUNTING PRACTICES

Arizona	Massachusetts
California	Minnesota
Connecticut	Mississippi
Delaware	Nevada
District of Columbia	New Hampshire
Florida	New York
Illinois	North Dakota
Iowa	Ohio
Kansas	Oklahoma
Kentucky	South Carolina
Louisiana	Tennessee
Maine	Virginia
Maryland	Wisconsin

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

standards and practices mandated for rural electric cooperatives by the federal Rural Electrification Administration.

In Florida, a true-up mechanism is used to balance any over- or underrecoveries of fuel costs. Florida Commission regulations specify that underrecoveries are to be covered in Account 186, Miscellaneous Deferred Debits. Overrecoveries are to be treated through Account 242, Miscellaneous Current and Accrued Liabilities or Account 253, Other Deferred Credits, whichever minimizes the tax liability to the utility.[13] The Maine Commission accounting requirements consist

[13] In re: General Investigation of Fuel Cost Recovery Clause, Docket No. 74680-CI, Order No. 9273, issued March 7, 1980.

of the data needed for the periodic fuel cost adjustment calculations. The utility must estimate the total sales and nonfirm energy sales for each month of the projected FAC period. The fuel cost adjustment is equal to the projected cost of fuel plus the reconciliation adjustment (described in the next section's discussion of true-up) minus the base rate fuel recovery. The fuel cost adjustment rate is equal to the fuel cost adjustment divided by the difference of the projected total sales and the projected nonfirm energy sales.[14] New York electric utilities enter any fuel cost debits into the deferred fuel costs subaccount of Account 186, Miscellaneous Deferred Debits, and the fuel expense accounts are then credited. If the fuel adjustment is negative, the amount is credited to the deferred fuel costs subaccount of Account 253, Other Deferred Credits, and the fuel expense accounts are then debited.

The FERC does not require any particular accounting procedures. The FERC Uniform System of Accounts does not mandate specific accounting for the FAC although the descriptions of allowed costs in the Commission's regulations dealing with FAC adjustments use classifications from the uniform system. With respect to purchased power, the FERC has not prescribed any record keeping or reporting requirements. The Commission does require a utility passing capacity charges through the FAC to prove (and thus maintain the needed records to show) that its system reserve capacity criteria were met at the time of the purchase. The utility must also show that the total avoided variable cost was, at the time of the power purchase, projected to be greater than the cost of the purchase. The avoided variable cost and the cost of the delivered power must also be furnished to the FERC.[15]

True-Up Procedures

The NRRI asked staff members whether their commissions' FAC procedures include a true-up. As with the PGA, true-up would be a very important part of the

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[14] See 65-407 Code of Maine Regulations Chapter 34.6 (A-D)(1986).

[15] The FERC Uniform System of Accounts is contained in the Code of Federal Regulations at 18 CFR Part 101. The FAC regulations are in the Code at 18 CFR Part 35.14.

FAC process since reconciliation of any over- or undercollection of costs occurs in this stage. True-up usually involves a balancing account in which the utility records the overcollections and undercollections of its fuel costs. At the end of the fuel adjustment period, these over- and undercollections are reconciled or balanced (that is, actual costs incurred are balanced against revenues received) and then may be factored into the next period's FAC. Table 3-14 shows the thirty-six commissions that have a true-up procedure in their FAC. The high number of commissions with a true-up indicates the importance of this procedure. Forty-two commissions, listed in Table 3-1, have fuel adjustment clauses and thirty-five of those commissions, as shown in Table 3-14, have a true-up.[16] Annual reconciliations or true-ups are fairly common among the commissions. Monthly true-ups are also required. Some commissions, such as Kansas and Maryland, may vary the true-up procedure depending on whether a large or small utility or a cooperative is involved. Comments on specific commissions follow.

In Alabama, a correction factor to handle any over- or undercollections is included in the FAC calculations. In Alaska, the larger utilities have balancing accounts and file quarterly. In Arkansas and Rhode Island, over- and undercollections are factored into the next adjustment period. California and Nevada utilities use balancing accounts to true-up any imbalances. Colorado utilities factor over- or underrecoveries into the fuel adjustment two months later. Connecticut, District of Columbia, Kentucky, and South Dakota utilities reconcile imbalances in the following month. South Dakota utilities add a carrying charge to any under- or overcollections. In Delaware, over- or undercollections are subtracted from or added to the estimated fuel cost and then factored into the FAC over the next twelve months. The FERC allows true-up but does not require it. The Florida Commission procedure requires the utility to apply the new true-up balance to any previous balance and then factor

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[16] The thirty-sixth commission in Table 3-14 is Virginia, which responded that it has a projected fuel factor and not a fuel adjustment clause. Virginia also responded that it has a true-up mechanism. Thus, it is listed in Table 3-14 but not in Table 3-1. The seven commissions that have fuel adjustment clauses but do not have a true-up procedure are Arizona, Minnesota, New Jersey, New York, North Dakota, Tennessee, and Wisconsin.

TABLE 3-14

COMMISSIONS WITH A "TRUE-UP" PROCEDURE IN THE FAC

Alabama	Maine
Alaska	Maryland
Arkansas	Massachusetts
California	Michigan
Colorado	Mississippi
Connecticut	Nevada
Delaware	New Hampshire
District of Columbia	New Mexico
FERC	North Carolina
Florida	Ohio
Georgia	Oklahoma
Hawaii	Pennsylvania
Illinois	Rhode Island
Indiana	South Carolina
Iowa	South Dakota
Kansas	Utah
Kentucky	Virginia
Louisiana	West Virginia

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

that new amount over the projected sales for the last four months of the next FAC period.[17] In Georgia, any over- or underrecoveries are factored into the next forecast period. In Hawaii, variances in the FACs are reported quarterly and adjustments are made.

In Illinois, annual reconciliation hearings are held. The Michigan Commission has annual reconciliation cases. In Utah, under or overcollections are balanced annually. True-ups are also done annually in Mississippi and New Mexico, whose

[17] In re: General Investigation of Fuel Cost Recovery Clause, Docket No. 74680-CI, Order No. 9273, issued March 7, 1980.

regulations require any utility with a fuel or purchased power cost adjustment to file a reconciliation of revenues with expenses each February 15. The utility's balancing account is also to be examined to insure that only the appropriate revenues are recovered.[18] The Maine Commission requires each electric utility to include a reconciliation adjustment as part of its annual FAC filing. The items to be covered in the reconciliation include any over- or undercollections of previous fuel costs, errors or erroneous reporting, imprudent fuel procurement policies, working capital costs associated with over- or undercollected fuel costs, and other practices or factors that the Commission considers appropriate.[19] In West Virginia, the utility's fuel component is audited annually and over- or undercollections are trued-up in the next FAC period. In Louisiana, the true-up involves calculating a surcharge by dividing the cumulative under- or overcollections by the previous twelve-month period's sales. In Maryland, small utilities recover under- or overcollections from the previous twelve months by applying a factor (a certain amount per kilowatthour) to the next year's bills. Large utilities in Maryland use deferred fuel accounts and recover the costs in base rates.

The Indiana Commission's true-up involves reconciling prior estimates to actual costs. The Iowa Board's regulations provide for a monthly calculation of the energy cost adjustment account balance representing the difference between the Board-approved energy cost recovery and the revenues received by the utility from rates.[20] The Kansas Commission has separate true-up procedures for generating and transmitting utilities on the one hand and cooperatives on the other. The true-up for generation and transmission utilities involves calculating a correction factor, consisting of the difference between the estimated and actual costs. This correction factor is included in each monthly FAC filing and covers the two prior months. The correction is then factored into the current month's estimated sales. For cooperatives

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[18] NMPSC Rule 550: Fuel and Purchased Power Cost Adjustment Clauses for Electric Utilities, 550.8(d): Information to be Filed (1988).

[19] 65-407 Code of Maine Regulations Chapter 34.4 (A)(1-7)(1986).

[20] Iowa Administrative Code, Chapter 20-Utilities, 199-20.9(476) (October 8, 1986).

any under- or overcollections for the current twelve-month period are balanced by being included in the next twelve-month period's FAC. In New Hampshire, costs and revenues are compared in each period and any imbalances factored into the next period's FAC. The Ohio Commission procedure is similar to New Hampshire. The initial FAC rate is based on estimated data. At the end of the period, actual costs and revenues are compared and under or overcollections are included in the next period's rate.

The South Carolina Commission allows prudent fuel costs from the preceding FAC period to be included in the next period's projected fuel component. These costs could be included either as a debit or credit depending on whether under- or overrecovery had occurred. Oklahoma utilities using a deferred account surcharge must true-up periodically. Incurred costs are compared with earned revenues and any difference is factored into the next period's FAC through the surcharge. North Carolina utilities use an experience modification factor (EMF) rider to balance any differences between prudent fuel costs and fuel related revenues that were experienced during the FAC period. North Carolina Commission regulations[21] specify that the EMF rider is to be attached (as an increment or decrement) to the base fuel cost component of rates as established in the utility's last rate case. The EMF is established for a twelve-month period and applies to any rates that may be set in intervening rate cases.

The New Jersey Board responded that it does not have a true-up procedure in its FAC process. Utilities' FAC filings must factor in any over and underrecoveries of costs from the previous FAC period but the rate is set for twelve months and no true-up period exists until the next filing.

Treatment of Overcharges

The NRRI asked staff members two major questions about the treatment of overcharges in the FAC process. The first question asked respondents to describe any

[21] See Rule R8-55: Annual Hearings to Review Changes in the Cost of Fuel and the Fuel Component of Purchased Power.

monitoring procedures used by the commissions to insure that customers are not overcharged (or undercharged) for fuel costs in the FAC. The second question asked about the mechanisms for making refunds to customers in the event that overcharges occurred. The topic of overcharges is an important one in considering FACs in particular and automatic adjustment clauses generally. An overcollection indicates that the FAC is working well enough, perhaps too well, to recover the utility's fuel costs. Recurring overcollections, especially if sizable, could be awkward for a commission because sustained and recurring overcollections harm ratepayers. Thus, it would seem important for a commission to have in place procedures for avoiding overcharges and for dealing with them when they occurred.

Table 3-15 shows the commissions with various types of FAC monitoring devices. The authors have divided the responses into four major categories: audits, accounting, utility reporting-filing, and other. A couple points about these categories should be made at the outset. First, the distinctions are somewhat artificial. For example, utility reports and filings are generally the basis for commission auditing and accounting. To work well, any type of commission oversight of the utility depends on that company providing the necessary information. Second, a commission's absence from a particular category in the table does not necessarily mean that the commission is not using that procedure at all. It merely signifies that the staff did not mention that mechanism in response to the question. Utility reporting-filing is a good example here as well. Electric utilities undoubtedly report or file data at all commissions but not all of the commission staffs mentioned reporting-filing as a monitoring device.

As shown in the table, audits and utility reporting-filing are two of the major monitoring devices that the commissions are using to prevent overcharges and undercharges. Eighteen commissions rely on audits and twenty rely on utility reporting-filing. A smaller number, ten, use accounting as a main monitoring procedure. Other types of procedures, oftentimes consisting of staff review, data compilation or hearings, are used by sixteen commissions.

With respect to audits, the commissions employ a variety of practices with respect to the timing and location of the review. Some commissions perform monthly audits. Other commissions perform audits quarterly, semiannually, annually, or every

TABLE 3-15

FAC MONITORING PROCEDURES USED BY COMMISSIONS*

Audits	Accounting	Utility Reporting/Filing	Other
Arkansas	Alaska	Alabama	Arizona
Colorado	Illinois	Connecticut	California
Connecticut	Massachusetts	Delaware	District of Columbia
District of Columbia	Michigan	District of Columbia	FERC
FERC	New Hampshire	Florida	Georgia
Florida	New Jersey	Hawaii	Indiana
Georgia	New Mexico	Iowa	Kentucky
Illinois	Pennsylvania	Kansas	Maine
Kansas	Rhode Island	Kentucky	Maryland
Minnesota	West Virginia	Louisiana	Nevada
Mississippi		Maine	New York
North Dakota		Maryland	North Carolina
Oklahoma		Minnesota	Pennsylvania
Rhode Island		Nevada	South Carolina
South Carolina		New York	Virginia
Utah		North Carolina	Wisconsin
West Virginia		Oklahoma	
Wisconsin		Pennsylvania	
		Tennessee	
		Wisconsin	
(N=18)	(N=10)	(N=20)	(N=16)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

*Some commissions are listed in more than one column because they responded that they use more than one of these procedures.

eighteen months. A smaller review may be performed more frequently with a more comprehensive review done after a longer time interval has elapsed. For example, a commission may audit the FAC filings monthly but also conduct a larger review of utility operations annually. Some commissions perform audits periodically or when a review is thought to be needed instead of on a set schedule. Some respondents commented that the utility is subject to an audit at any time. Audits may be performed at the utility's offices or at the commission's offices. Commission staff or independent auditors who may be supervised by commission staff usually conduct the reviews. Comments on specific commissions follow.

The Arkansas Commission is required by state law to audit electric utility automatic adjustment clauses every eighteen months. The Colorado Commission conducts monthly audits. In Connecticut, the utility is subject to audit at any time. The District of Columbia Commission includes audits as part of its FAC monitoring. Staff audit of the monthly FAC filing forms the basis for Commission approval or disapproval of the filing. In addition, a comprehensive audit of all of the utility's operations and activities that are related directly to fuel costs is performed every four years and covers procurement, accounting, planning, and management. This comprehensive review is usually conducted by independent auditors supervised by Commission staff. The utility also audits its FAC monthly and annually and these papers are reviewed by Commission staff.

The FERC has the authority to review utility books and records at any time and regularly conducts compliance audits. Auditors from the FERC Office of Chief Accountant examine utility compliance with the Commission's regulations on accounting, financial reporting, and tariff billing. Fuel costs are given special emphasis during the audits to insure that the utility is complying with FERC requirements on accounting and rates. Auditors try to determine whether the utility's fuel cost accounting is consistent with the FERC uniform system and accepted accounting principles. Other aims of the audit are, first, to insure that utility FAC billings to wholesale customers conform with the provisions of the utility's FAC, second, to insure that the fuel cost component of the billings contains only those items approved by the FERC and set forth in the Commission's regulations, and third, to insure that the utility's incurred costs were not unjust or unreasonable.

The Florida Commission conducts FAC audits every six months at the utility offices. The Georgia Commission also conducts regular field audits. In Illinois, monthly desk audits are performed. The Mississippi and South Carolina Commissions conduct quarterly audits. The North Dakota, West Virginia, and Wisconsin Commissions undertake annual audits. The Oklahoma Commission conducts semiannual audits. The Kansas Commission staff undertakes comprehensive audits when necessary. The Utah Division of Public Utilities conducts periodic audits. The Minnesota Commission's rules specify that all gas and electric utilities must submit annually an independent auditor's report. The audit must evaluate the accounting of the automatic adjustment clauses for the prior year July 1 through June 30.[22] Rhode Island utilities purchase almost all of their power from other utilities that are located outside of the state and are regulated by the FERC. The Rhode Island Commission has limited staff and thus relies on the FERC audits of the companies selling power to Rhode Island utilities.

Twenty commissions rely on utility reporting-filing as a major monitoring procedure to insure customers are neither overcharged nor undercharged. Many of the commissions discussed below require the utilities to file monthly reports on their fuel costs. Some commissions also verify the calculations that the utilities submit in their FAC filings. In short, this group of commissions relies on their abilities to be vigilant and the assumed trustworthiness of the utilities for this type of monitoring to work effectively. Comments on specific commissions follow.

In Alabama, the utility submits a monthly report on energy costs and cumulative under or overrecovery of actual costs from application of the FAC. The Connecticut Department compares utility FAC filings with the published fuel price data that it receives monthly. In Delaware, the utility files monthly schedules in support of its calculated fuel costs. The schedules are examined by Commission staff. Florida, Kentucky, and Wisconsin utilities must file monthly fuel cost reports with

[22] See Minnesota Rules 7825.2820.

their respective commissions. Nevada utilities make monthly letter filings that are reviewed by the Commission staff. Tennessee Commission staff review the FAC filings monthly. The Hawaii Commission's regulations require utilities to file the relevant contracts and prices with the Commission before any changes in fuel and purchased energy costs can be included in the FAC. The utility must also file with the Commission the calculation of any change in the FAC that it plans to make (and the supporting data) prior to the effective date of the change.[23] Iowa Board regulations set forth in detail the types of costs and the calculations that utilities are to include in their FAC filings.[24] In Louisiana, the FAC filings are to include a sworn affidavit. In Maine, the PUC staff reviews monthly and annual reports. In the District of Columbia, the utility must file an annual productivity improvement plan including a forecast of the next year's monthly fuel prices, consumption, and expenditures. The utility must also file progress reports and the prior year's plan and forecast. This document is reviewed by Commission staff and the District of Columbia's Office of the People's Counsel.

The Maryland Commission accounting staff and the Maryland Office of the People's Counsel review FAC filings. There is also a monthly review of the small utilities' purchased power costs. The Minnesota Commission requires all gas and electric utilities to submit annually a report detailing the monthly automatic adjustment clause charges for each customer class for the prior year of July 1 through June 30. The utilities must file the report by September 1.[25] In New York and Kansas, staff reviews and verifies the monthly utility FAC filings. For New York, the cost of fuel, utility generating and distribution efficiencies, and the quantity of fuel purchased are particular areas of concern in the review.[26] The North Carolina Commission requires utilities to file monthly fuel reports and monthly base load

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[23] See Section 6-60-6 of Administrative Rules (1981).

[24] See Iowa Administrative Code, Chapter 20-Utilities, 199-20.9(476) Electric Energy Sliding Scale or Automatic Adjustment (October 8, 1986).

[25] See Minnesota Rules 7825.2810.

[26] See Paragraph 136.57 of 16 NYCRR (1985) for more about the review.

power plant performance reports. The Commission holds annual hearings for each utility generating power with fossil or nuclear fuel to consider any changes in the cost of fuel and in the fuel component of purchased power. Other types of data, such as generation data, sales, testimony, and workpapers, are to filed with the Commission at least sixty days prior to the hearing.[27] The Oklahoma Commission staff verifies the monthly FAC calculations using the documentation submitted along with the filing. The Pennsylvania Commission staff also verifies the FAC calculations and reviews any new filed tariff rates and current rates.

Ten commissions rely on accounting procedures as a major monitoring device. Many of these commissions use balancing accounts or reconciliation of over- or underrecoveries or both as discussed in the previous section on true-up mechanisms. In Alaska, the larger utilities must maintain balancing accounts. The Massachusetts Department and the Illinois, Michigan, and Pennsylvania Commissions have reconciliations of over- and underrecoveries of costs. New Hampshire utilities file monthly reconciliations of under- or overrecoveries. Interest is applied to any balance at the prime rate. In New Jersey, deferred accounting is used. Over- and underrecoveries are factored into the next period's FAC. In Rhode Island, the fuel adjustment clauses require the full reconciliation of any under- or overrecoveries in the next FAC filing. In West Virginia, over- and underrecoveries are trued-up in the following FAC period. New Mexico utilities must maintain balancing accounts and perform annual reconciliations.[28]

Sixteen commissions are listed in Table 3-15 as using other types of monitoring procedures, many of which consist of commission reviews, hearings, or data collection. The Arizona Commission has assigned one staff member to monitor the monthly fuel adjustments and determine if a proceeding should be initiated. If a case is begun, several staff members would be assigned. The California Commission conducts a

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[27] See Rule R8-55: Annual Hearings to Review Changes in the Cost of Fuel and the Fuel Component of Purchased Power.

[28] See the New Mexico Public Service Commission regulations at NMPSC Rule 550-Fuel and Purchased Power Cost Adjustment Clauses for Electric Utilities, 550.8(b) and 550.8(d)-Information to be Filed (1988).

reasonableness review annually. The District of Columbia Commission undertakes a major review of the utility's fuel costs during the course of each rate case. In addition, the Commission has instituted a productivity improvement program that includes the audits and the productivity improvement plan discussed above. The program also includes the creation of a Productivity Improvement Working Group, involving Commission engineers, accountants, lawyers and economists, representatives of the utility and of the Office of the People's Counsel. This group has monthly meetings to consider, among other issues, fuel-cost-related matters. The FERC is required by section 208 of the Public Utilities Regulatory Policy Act to review automatic adjustment clauses to insure resources are used efficiently. The Commission must issue a report every four years on utility fuel practices. The Georgia Commission checks the utility's fuel inventory methods and studies the prudency of fuel purchasing.

The Indiana Commission uses a procedure known as the "D-2" test. The Commission staff reviews the utility's income statement to determine if any increases in fuel costs can be balanced by decreases in other operating expenses. The Kentucky Commission conducts hearings every six months and every two years. The staff reviews the utility's monthly reports and conducts annual field reviews. The Maine Commission conducts any necessary additional discovery and cross-examination proceedings growing out of its review of the utility's monthly and annual reports. The Maryland Commission also holds hearings. The Nevada and North Carolina Commissions conduct annual reviews. The New York Department of Public Service compiles data on the prices paid for fuel by New York utilities. The Department's Office of Utility Efficiency & Productivity studies fuel procurement practices and the New York Commission has investigated prolonged utility outages to determine their causes. The Pennsylvania Commission staff compares projected supply and sales volumes to historical data to determine the reasonableness of the projections. The Commission also verifies the rates used to calculate the projected fuel costs. The South Carolina Commission reviews fuel costs monthly. The Virginia Commission monitors utility cost recovery monthly via a computerized system. The Wisconsin Commission has conducted a prudence review of a utility's coal contract.

Having considered the variety of procedures that the commissions use to guard against overcharges (and undercharges), the next issue to discuss is what the regulators do in the event that overcharges occur. The NRRI asked the staff members whether their commissions' FAC procedures include explicit provisions for making refunds to customers, whether overcharges are deducted from the next period's FAC charge, or whether some other mechanism is used. The responses are shown in Table 3-16.

Offsetting any overcharges in the next FAC period is clearly the favored option among the commissions. Twenty-nine commissions offset overcharges while only twelve use refunds. Four commissions, Alaska, Nevada, Ohio, and Oklahoma, use both procedures. Five use other mechanisms, although those other procedures do not differ greatly from offsets and refunds. Offsetting overcharges undoubtedly is more easily incorporated into established commission FAC procedures, such as true-up and deferred or balanced accounting. Many of the respondents mentioned their commissions' true-up mechanisms in answering this question. Thus, it is not too surprising that offsetting is the more common method for dealing with overcharges. Comments on specific commissions follow.

Commissions that offset overcharges in the next period's FAC and offered additional explanation are considered first. The District of Columbia Commission's FAC results in a dollar-for-dollar recovery of costs including any over- or undercharges. The Florida Commission's true-up procedure applies any leftover balance to the new true-up and factors that amount over the projected sales for the last four months of the next FAC period.[29] Hawaii utilities report any variances in the FAC quarterly. Adjustments are then made in the fuel factors. In Iowa, any over-or undercollections are factored into the next month's filing. Similarly, in Louisiana overcharges by the utility are subtracted from the next month's filing. The Maine Commission requires utilities to compute a reconciliation adjustment factor in their FACs. This adjustment includes overcollections and unrecovered reasonable fuel

[29] In re: General Investigation of Fuel Cost Recovery Clause, Docket No. 74680-CI, Order No. 9273, Issued March 7, 1980.

TABLE 3-16

COMMISSIONS USING CERTAIN FAC MECHANISMS TO RETURN OVERCHARGES TO CUSTOMERS*

Explicit Refund Provision In the FAC	Overcharges Offset In the Next Period's FAC	Other Mechanism Used
Alaska	Alaska	Arizona
Connecticut	Arkansas	Kansas
FERC	California	Massachusetts
Kentucky	Colorado	New Mexico
Michigan	Delaware	Wisconsin
Minnesota	District of Columbia	
Nevada	Florida	
New York	Georgia	
Ohio	Hawaii	
Oklahoma	Illinois	
Tennessee	Indiana	
Virginia	Iowa	
	Louisiana	
	Maine	
	Maryland	
	Mississippi	
	Nevada	
	New Hampshire	
	New Jersey	
	North Carolina	
	North Dakota	
	Ohio	
	Oklahoma	
	Pennsylvania	
	Rhode Island	
	South Carolina	
	South Dakota	
	Utah	
	West Virginia	
(N=12)	(N=29)	(N=5)

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

*Some commissions are listed in more than one column because they responded that they used more than one of the procedures.

costs and is factored into the next FAC calculation.[30] In New Hampshire, actual costs from the FAC period are compared with the revenues earned during that time and any over- or undercollection is then factored into the next period. The North Carolina Commission's true-up procedure applies any over- or undercollections as an increment or decrement to the base rate fuel cost component as set in the utility's last rate case.[31] The South Carolina Commission true-up procedure allows prudent fuel costs from the previous period to be included in the next period's FAC projected fuel costs. These costs may be included as either a debit or a credit.

As noted above, the Alaska, Nevada, Ohio, and Oklahoma Commissions use both the offset and refund mechanisms for dealing with overcharges. Three of these states offered additional comments. Generally, refunds are used for special circumstances at these commissions while offsets appear to be the normal course. In Alaska, the large utilities maintain balancing accounts. If the utility does not reduce its surcharge quickly enough for the Alaska Commission, it may be ordered to pay a refund. In Nevada, any overcollection due to a billing error would be refunded. Other types of overcollections would be handled through the balancing account. In Oklahoma, any over- or undercollections due to errors in calculations of the FAC or other types of arithmetical errors would be passed through the FAC in the following period. Larger amounts would be recovered through a method that the utility and the Oklahoma Commission negotiated or that the Commission ordered. In some instances, a surcharge and period of time for balancing out the under- or overcollection are set. In other instances, customers receive refunds or credits.

Commissions with explicit refund provisions in their FACs include the FERC, which requires the utility to issue timely refunds to any customers that have been overcharged. If a tariff violation is the cause of the overcharge, the utility must recalculate the FAC adjustment factor for the time during which the overcharge occurred. The customer would receive a refund consisting of the difference between the original billing and the corrected FAC adjustment plus interest. In Connecticut,

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[30] See 65-407 Code of Maine Regulations Chapter 34.4(A) and 34.6 (1986).

[31] See Rule R8-55(c)(2-5).

refunds are treated in the same manner as charges. In Virginia, the fuel factor is revised after the prior period's over- or underrecovery of costs is compared with projected expenses.

Commissions using other types of mechanisms to return overcharges to customers include Arizona, whose policy is a combination of offset and refund. Refund checks may be issued to customers or credits may be placed on customer bills. The fuel adjustor rate may also be modified to return the overcharges over a period of time. In Kansas, a correction factor covering the two prior months is included in each monthly FAC filing by utilities that generate or transmit their own power. This correction consists of the difference between actual and estimated costs and is factored over the current month's estimated sales. For cooperatives, any cost under- or overrecovery from the previous twelve months is factored into sales for the next twelve months. In Massachusetts, if the utility realizes an overcollection greater than 10 percent or if its unit costs decrease by greater than 5 percent, it must apply to the Massachusetts Department for an interim FAC modification. The Wisconsin Commission uses a per kilowatthour surcharge, triggered by a change of plus or minus 3 percent.

FAC Incentive Mechanisms

The next topic considered is FAC incentive mechanisms. As with purchased gas adjustments, FAC incentive mechanisms are intended to provide the utility with reasons or incentives to keep its fuel costs as low as possible consistent with service reliability as an alternative to the commission simply ordering the utility to do so. The incentives can be positive or negative and, as with the PGA, incentive regulation can be an important tool for commissions to use in the area of FACs. The NRRI asked the staff members whether their commissions' FAC procedures include any incentive mechanisms for fuel cost minimization. Table 3-17 shows the thirteen commissions that responded that their procedures do incorporate incentives, a somewhat small number indicating that the idea of FAC incentives does not appear to be very popular among commissions. Some commissions responded that their

TABLE 3-17

COMMISSIONS WITH FAC INCENTIVE MECHANISMS INTENDED TO MINIMIZE THE COST OF FUEL

Arkansas	Nevada
California	New Hampshire
Delaware	New York
District of Columbia	Ohio
Florida	Virginia
Kentucky	Wisconsin
Maine	

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

oversight of the utility or the disallowance of costs or both is the incentive mechanism. Some commissions have incentives designed to reward or penalize the utility for power plant performance or for fuel expenses by allowing the company to keep a certain share of any savings or forcing it to absorb a share of the losses. One commission has an incentive designed to shift sales from the peak period to the off-peak. Comments on specific commissions follow.

In Arkansas, one utility's fuel adjustment clause includes an incentive for its nuclear plants. Capacity factors are set and stockholders receive 10 percent of any fuel savings that may result when those factors are surpassed. The FAC for the same utility also includes incentives to reduce the time lost from refueling the nuclear plants. In this instance, different formulas are used with a 10 percent difference in cost recovery depending upon the amount of time lost for refueling.[32] The Delaware Commission has a power plant performance program in which rewards or penalties are doled out based on the availability factor of fossil fuel plants and the capacity

[32] Arkansas Power & Light Company, Fuel Adjustment Clause Rider, Rate Schedule M27, September 1, 1983.

factor of nuclear plants. The District of Columbia Commission's monitoring (including the audits and the productivity improvement program described previously) and true-up procedures are its incentive mechanism. The Kentucky Commission's incentive consists of its oversight of the utility, which includes hearings every six months and two years, fuel reviews, and reports submitted each month by the utility to the Commission. The Nevada Commission incentive consists of limiting recovery of costs to those that are reasonably incurred. The Virginia Commission indexes generating unit performance against the return on common equity.

The Maine Commission has an incentive provision intended to make peak period sales less profitable and thus encourage utilities to shift peak sales to off-peak periods. The fuel portion of rates is to be 15 percent higher in the peak period than in the off-peak. Nonfuel revenues are diverted to the off-peak period, providing a hoped-for incentive to conserve or shift peak load.[33] The Wisconsin Commission's incentive mechanism consists of annually setting a target figure (weighted cost of fuel per Kwh) and creating a "dead-zone range" of plus or minus 3 or 2 percent around that target as well as a monthly range of 10 percent. If the utility's costs fall below that target, it can keep the savings up to 3 or 2 percent. If costs are above the target, it must absorb them until an audit is performed and a new target set. The New York Commission's incentive involves a partial pass-through of costs. In a rate case, an incentive target is set for every month of a specified time period. Each month, the average fuel cost is compared with the target. The company is allowed to keep 20 percent of any savings if the average monthly cost is below the target but must absorb 20 percent of any losses if the cost is above the target. Ratepayers gain or lose the other 80 percent. These variations are allowed to accumulate in a particular year up to a cap set for each company.

The Ohio Commission has several incentive mechanisms. The first is a measure of cost effectiveness, a number based on a variety of fuel cost related factors. Recovery of incremental fuel costs caused by system losses and not included in base rates is based on this measure. Because the measure is unpredictable and the

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[33] In re: Central Maine Power Company and Bangor Hydro-Electric Company Fuel Revenue Accounting; Docket No. 87-220, Corrected Order, December 18, 1987.

amount of money involved is usually small, staff feels that this incentive may not be effective. The Ohio Commission conducts annual financial and management audits on fuel practices. The Commission has incorporated nuclear plant performance standards into rate cases. The Commission also has open hearings in which other parties can intervene and the utility must show its costs to be just and reasonable. The Florida Commission has a generation performance incentive factor. This incentive involves setting equivalent availability and average heat rate performance targets for a utility's base load power plants. These targets are projections of the units' performance over the following six months as included in the projected FAC. A range of potential improvement is set for each target and weights are calculated for each range. These weights are a reflection of the contribution to system fuel savings that would result from achieving the maximum potential improvement. At the end of the six months, the actual equivalent availability and heat rates are compared to the targets. Rewards or penalties are then given to the utility for going beyond or falling short of the improvement targets. These rewards or penalties would be monetary.[34]

The California Commission has used an annual energy rate (AER), placing utilities at risk for a certain percentage of their fuel costs. The Commission felt that guaranteeing 100 percent recovery of costs through the balancing account procedure did not give utilities sufficient incentives to keep their fuel costs as low as possible. In 1980 the Commission instituted the AER, placing the utility at risk for 2 percent of its costs by not guaranteeing recovery. In 1983 the California Commission, feeling that 2 percent was an insufficient incentive, decided to raise Southern California Edison's AER to 10 percent. In response to utilities' concerns that an increase in the AER percentage would add to their earnings fluctuations and increase their cost of capital, the Commission decided to cap the earnings to which the AER would apply. In the case of Edison, the Commission calculated a cap of 160 basis points to be applied to the utility's pre-tax equity base. The AER and cap figures for Edison were meant to be benchmarks from which the Commission would depart in deriving figures

[34] See In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Docket No. 800400-CI, Order No. 9558, issued September 19, 1980.

for other utilities. The Commission calculated the AER and cap for the other companies by comparing the risk level and financial status of each to Edison. For example, the AER established for Pacific Gas and Electric was 9 percent with a cap of 140 basis points.[35]

Other commissions responding that they do not have incentives provided some additional comments. The Connecticut Department staff feels that the lag of two months needed to recover funds in the FAC process may be a type of incentive although not a formal mechanism. In Minnesota, fuel costs are averaged for all customer classes. Interruptible service is competitive and this averaging may provide an implicit incentive. The Oklahoma Commission expects its jurisdictional utilities to minimize costs through responsible management. The South Carolina Commission expects the company to show that all of its costs are prudent. The state of Alaska has a power cost equalization program through which the state pays part of the power costs for rural areas. If a utility does not meet a minimum efficiency standard of kilowatthour sales per gallon of fuel, the fuel cost component of the power cost equalization is still calculated as if the minimum were met.

The authors asked staff members how effective their commissions' FAC incentive mechanisms have been. The responses were mixed. Some were not sure and some thought their incentives were working while others thought theirs were not. Among the unsure was the Arkansas Commission, which has found that the utility has exceeded the capacity factor targets consistently. However, staff is not sure whether the incentives have worked or whether the targets were set too low. Respondents from the District of Columbia and Florida Commissions also were uncertain. The Delaware Commission has ordered the utility to quantify the savings that customers have received from its incentive mechanism.

Respondents from Maine, Ohio, Virginia, and Wisconsin feel that their Commissions' incentives have worked. In Maine, there has been less peak growth and improved system load factor. In Ohio, fuel costs are generally lower than ten years

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[35] See California Public Utilities Commission, Division of Ratepayer Advocates, Fuels Branch, *Briefing Paper: The Annual Energy Rate (AER): An Incentive for Electric Utilities in California from 1980-1989* (January 1990).

ago. One utility has agreed to refund a portion of costs collected from an affiliated coal company and to cap its future recoveries. Staff feels that these developments are due at least partly to the incentives. In Virginia, the utilities with improved power plant performance have experienced a major decrease in their fuel expenses. The Wisconsin Commission takes more responsibility for insuring the reasonableness of fuel costs because it sets the target for the incentive rate. The incentive is easier to quantify and to prove than a prudence case.

In some instances, the incentives have not worked as well as planned. The California Commission has had some problems with the annual energy rate, whose calculation required a utility's forecasts of its fuel costs for each adjustment period. In some cases, there has been disagreement between the utilities and the California Commission over the projections and the Commission has had to suspend the AER for certain utilities because no projected cost figures were available. In addition, the volatility of energy prices made forecasting the fuel costs more difficult and uncertain. The Commission, trying to reach a solution to the problem of how to proceed when the adjustment period had expired and there were no forecasted costs available for the calculations, decided that the AER would be suspended for a utility when the forecast period to which it applied ended.

In addition to the administrative problems with the AER just discussed, a California Commission staff report on the program concluded that the rate was providing insufficient incentives to accomplish its goals and was having minimal impact on the utilities' financial conditions. The levels of the AER percentages were established with the intent of each utility reaching its earnings cap 20 percent of the time or once every five years. However, only one utility had reached its earnings cap between 1981 and 1988, meaning that the AER was not placing the intended pressure on the utilities' profits or losses. The staff also found that the AER was having little impact on the utilities' return on equity and stockholders' earnings per share. The staff recommended that the Commission consider raising the AER percentage levels thus placing utilities at greater risk.[36] The New York Commission's incentive has also

[36] Ibid.

not operated satisfactorily enough for the Commission. The design of the incentive does not distinguish sufficiently between cost fluctuations due to oil price swings and those due to efficiencies. A Commission task force has suggested that indexing be used to counter the effects of any oil price swings.[37]

Other FAC-Related Issues

The authors included several other questions in the survey dealing with other issues that the FAC might affect. Many of these issues are related to the changing market structures of the electric industry and the NRRI wanted some indication of the extent to which the commissions are responding to these changes by modifying their established procedures. The questions covered the FAC in a more competitive power market including the pass-through of capacity costs as more independent power producers (IPP) and qualifying facilities (QF) come on line, FAC encouragement of self-generation, FAC treatment of power purchased from an affiliated QF or IPP, and FACs for power purchased from QFs or IPPs in a competitive bidding setting. These issues are discussed in four subsections below.

FAC in a More Competitive Power Market

The authors asked a three-part question about the FAC and the more competitive power market. Staff members were asked first whether their commissions have addressed the regulatory implications of their FACs for ratemaking in a more competitive market. If the answer was yes, they were then asked if their commissions have considered the implications of passing through capacity costs contained in purchased power as more IPPs and QFs come on line, and whether their commissions have addressed the effect of the capacity costs on customer class cost allocations.

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[37] See Order Instituting Proceeding, Directing the Filing of Information, Inviting Comments, and Closing Pending Proceedings, Cases 90-E-0954, 29722, 88-E-213, issued November 7, 1990.

The commissions responding affirmatively to these questions are shown in Tables 3-18, 3-19, and 3-20 below.

As can be seen from the tables, rather few commissions have considered these issues. Eleven commissions are listed in Table 3-18 as having addressed the regulatory implications of the FAC in a more competitive power market. These implications include the effect of passing through capacity costs as a part of a fuel adjustment as more nonutility generators come on line, whether existence of an FAC skews a utility's evaluation of whether to purchase power, and whether the existence of an FAC skews the bidding criteria and evaluation in competitive bidding. A slightly higher number, thirteen, are shown in Table 3-19 as having considered the implications of passing through capacity costs from IPPs and QFs. As shown in Table 3-20, a small number, six, have considered the effects of these IPP and QF capacity costs on customer class cost allocations. The low numbers probably indicate that these are questions that many commissions have not yet had to face. Given the ongoing restructuring of the electric utility market, more commissions undoubtedly will have to consider these issues in the future. Comments on specific commissions follow.

The California Commission has addressed all of these questions. These costs are treated in the same manner as fuel costs. The Colorado Commission has addressed the regulatory implications of the FAC in a more competitive market and has held hearings on utilities' criteria for accepting new IPPs and QFs. The Connecticut Department has considered all of these questions. Costs from IPPs and QFs are passed on to customers through the FAC. The Delaware Commission also has addressed these issues except for the effects on customer class cost allocations. The Commission turned down a utility's request to use a surcharge on base rates to recover the cost of reliable capacity and wheeling incurred from power supply agreements with third parties. The Commission decided that the capacity costs of purchased power should be recovered in base rate cases. The Maryland Commission has begun to address these issues. It has found that passing through QF and IPP capacity costs has implications for customer class cost allocations and has supported a utility proposal to allocate capacity costs on a 4CP (four coincident-peak) method. The four peak days for the year and each customer class's contribution to those peaks

TABLE 3-18

COMMISSIONS ADDRESSING THE IMPLICATIONS OF THE FAC IN A MORE COMPETITIVE ELECTRIC POWER MARKET

California	New York
Colorado	Ohio
Connecticut	Oklahoma
Delaware	Utah
Maine	Wisconsin
Maryland	

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

TABLE 3-19

COMMISSIONS THAT HAVE ADDRESSED THE IMPLICATIONS OF PASSING THROUGH CAPACITY COSTS FROM IPPs AND QFs

California	New Jersey
Connecticut	New York
Delaware	Ohio
Maine	Oklahoma
Maryland	Utah
Massachusetts	Wisconsin
Michigan	

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

TABLE 3-20

COMMISSIONS THAT HAVE ADDRESSED THE EFFECTS OF CAPACITY COSTS FROM IPPs AND QFs ON CUSTOMER CLASS COST ALLOCATIONS

California	Maryland
Connecticut	Oklahoma
Maine	West Virginia

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

are determined. The contributions to peak are then averaged for each customer class. The Massachusetts Department has addressed the regulatory implications of passing through the capacity costs, but not customer class cost allocation issues. The utility recovers long-term capacity costs through fuel charges until its next rate case.

The Michigan Commission has considered the pass-through of the capacity costs. IPP and QF power is treated in the same fashion as any other source of power. The New Jersey Board has considered the implications of pass-through. Qualifying facilities' and independent power producers' capacity and energy receive standard FAC treatment. The New York Commission has considered the regulatory implications and the pass-through of capacity costs, but not customer class cost allocation issues. In a bidding arrangement, FAC recovery of the energy costs is allowed while capacity costs are to be recovered generally through base rates.[38] The Ohio Commission has addressed the regulatory implications and pass-through

[38] See Opinion No. 91-2, Opinion and Order Establishing Power Purchase Contract Policies and Procedures, Case 90-E-0675, Case 27824, issued February 25, 1991.

questions to a limited extent, but has not considered customer class cost allocations. The Utah Commission has considered the regulatory implications and pass-through questions. The Commission decided against FAC recovery of QF demand costs. The West Virginia Commission has considered the issue of customer class cost allocations deciding that all demand costs are to be allocated among the customer classes on the basis of Commission-approved cost-of-service factors. The Wisconsin Commission has considered the regulatory implications and the pass-through questions, but not customer class cost allocations. Commission staff has recommended against the use of competitive bidding in Wisconsin.

Some commissions that have not addressed the regulatory issues being discussed in this section offered additional comments. The FERC has, in the words of the staff respondent, addressed "peripherally" the issue of regulatory implications of the FAC in a competitive market. Power purchased from QFs and IPPs is given the same FAC treatment as other power with the energy portion of economic dispatch purchases passed through. Expenses resulting from power transactions lasting less than twelve months (and the total cost of which is less than the internal incremental cost) are also allowed to be recovered in the FAC. Many purchases from QFs may not meet these criteria and thus not be allowed FAC recovery. The Minnesota Commission has begun a proceeding on incentive regulation with no conclusions having been reached as of the time of this survey.

FAC and Self-Generation

The authors asked the staff members if their commissions have considered whether their FAC procedures encourage self-generation by customers. This issue has received very little attention from the commissions. Only Massachusetts and Ohio have addressed this question. The Ohio Commission staff view is that the pass-through of capacity charges on economic purchases that are less than the company's incremental fuel costs should discourage any uneconomic self-generation.

FAC and Affiliated QFs and IPPs

The authors asked the staff members whether their commissions' FAC procedures treat power purchased from an affiliated QF or IPP any differently than other fuel costs. Only the three commissions listed in Table 3-21--Connecticut, New Hampshire, and Ohio--responded that they have a different FAC treatment for such power purchases. In Connecticut, all costs of QF power, including capacity and administration in addition to fuel, are passed through the FAC in the same manner as a utility's fuel costs. The New Hampshire Commission allows IPP costs to be passed on, treating all of the costs as if they are fuel costs. There are no affiliated QFs in the state. The Ohio Commission has allowed affiliated purchased power costs from a hydro facility and from a trash burning power plant to be passed through the FAC. The entire amount is allowed and there is no separation of fuel, energy, and capacity costs. These facilities have been considered on a case-by-case basis.

TABLE 3-21

COMMISSIONS WITH DIFFERENT FAC TREATMENT FOR POWER PURCHASED FROM AN AFFILIATED QF OR IPP

Connecticut
New Hampshire
Ohio

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

FAC, QFs, IPPs, and Competitive Bidding

The authors asked staff members whether their commissions have considered what kind of fuel adjustments would be appropriate for power purchased from qualifying facilities and independent power producers that win competitively bid power supply contracts. Five commissions have addressed this issue and are shown in Table 3-22.

In Connecticut, the FAC flows the cost of QF power through to the ratepayers. The price paid to the QF is not adjusted on the basis of the fuel costs of the facility. The avoided costs of the utility or the Consumer Price Index are the determining factors. In Nevada, current policy is to recover all purchased power costs. The New Jersey Board allows FAC treatment for QF and IPP contracts. In Virginia, purchased power from an affiliated QF or IPP is not treated any differently. The New York Commission has issued an order providing for recovery of QF contract costs incurred in competitive bidding. Contracts for energy only are to fully recovered through the FAC. Other contract costs are to be split into energy and capacity components with the capacity costs recovered in base rates. Contracts with small facilities of 2 MW or less, however, can be recovered fully through the FAC although such agreements also contain some capacity charges. The Commission felt that the rate impact of these contracts would be minimal and would not justify the utility and Commission staff resources needed to separate their costs into energy and capacity.[39]

The Wisconsin Commission has not yet addressed this issue. There are no QFs or IPPs currently operating in the state and the Commission will consider the appropriate fuel adjustments when some facilities come on line. The FERC also has not considered this question. As noted previously, power purchases from QFs and IPPs are treated in the same fashion as other power purchases.

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[39] Ibid.

TABLE 3-22

COMMISSIONS ADDRESSING THE TYPE OF FUEL ADJUSTMENTS APPROPRIATE FOR QFs AND IPPs IN COMPETITIVE BIDDING

Connecticut
Nevada
New Jersey
New York
Virginia

Source: NRRI survey on public utility commission electric fuel adjustment clause practices, 1990.

Summary

Responses were received from forty-nine state utility commissions, the District of Columbia Commission, and the Federal Energy Regulatory Commission. The vast majority, forty-two, of the commissions have fuel adjustment clauses. Only nine do not. Twenty-three have a generic order, rule, decision, and so on providing a uniform treatment while twenty treat the FAC on an ad hoc basis. Three commissions combine both methods and two use neither. Forty-one commissions have long-standing FACs (five or more years old) and two have recently established mechanisms. Four commissions have abolished FACs usually because of action directed by the state courts or the state legislature.

With respect to FAC filings, most commissions require the utility to submit information on a set schedule. Twenty require the utility to file monthly, while eleven commissions have an annual filing requirement. Five have a quarterly filing requirement and four have a semiannual filing requirement. Five commissions require the utility to file on some basis other than a regular fixed schedule. Usually the utility must file when the cost of its fuel changes. There is some overlap among these categories because commissions may have different filing requirements for different electric utilities or they may have multiple filing requirements for the same utility during the course of a year.

Basic types of data required by many of the commissions include sales in kilowatthours, fuel and purchased power invoices, the actual cost of fuel for the previous adjustment period, the estimated cost of fuel for the next period, the amount of purchased power, generation costs and mix, the reconciliation from the previous period, power plant performance data, and data on outages. The commissions vary by the amount of and types of data that they want the utilities to submit in their FAC filings.

Most (twenty-nine) commissions hold hearings on utility FAC filings. Seventeen have hearings on every filing and twelve conduct such proceedings only on certain filings. Those holding hearings only on certain filings may do so to consider disputed items or new or unusual matters. Twenty-three commissions are required to hold hearings with annual and semiannual proceedings being the most frequently required types. Thirty-seven commissions said that their hearings are public; none said their hearings are closed. Ten commissions grant confidential protection to purchased power contracts considered during the hearings. At three of the ten, confidentiality is provided only if requested by the utility.

The commissions allow the basic types of costs to be recovered through the FAC. Forty-one commissions allow fossil fuel costs to be passed through while thirty-three allow nuclear fuel cost recovery. Administrative costs associated with fuel procurement are allowed by only eight commissions. Another cost allowed by many commissions is purchased power. Forty-one commissions allow the energy component of power to be passed through the FAC while twenty-three allow the demand component. With respect to the treatment of cost increases and decreases, the responding commissions were nearly unanimous in saying that cost decreases are treated no differently than cost increases and that cost decreases are passed on as quickly as increases.

Twenty-six commissions require the utilities to use particular accounting practices. About half of these (twelve) mandate the use of the FERC Uniform System of Accounts. Thirty-six commissions have a true-up procedure as part of their FAC process. Annual reconciliations are fairly common, as are monthly. Many commissions use monitoring devices of some sort to avoid overcharges and undercharges of customers. Utility reporting-filing is the most frequently used monitoring technique with audits and accounting also used. When overcharges occur, commissions prefer to offset them in the next period's FAC. Twenty-nine use offsets while twelve use refunds.

Incentive regulation appears to be somewhat unpopular, at least with respect to FACs. Thirteen commissions said that their FACs included incentives. Staff provided mixed responses on the effectiveness of the incentives. About one-third of those from commissions with incentives were uncertain about how effective they have been. Another third felt that the incentives have worked. Two commissions have had some problems with their incentives and modifications have been proposed.

The survey included several questions about the FAC and the changing electric market. Few commissions have considered the issues raised in the questions, perhaps because they have not yet had to face them. Eleven commissions have addressed the regulatory implications of the FAC in a more competitive power market. Thirteen have considered the implications of passing through capacity costs from IPPs and QFs. Six have considered the effects of these IPP and QF capacity costs on customer class cost allocations. Two commissions have considered whether their FAC procedures encourage self-generation. Three have a different FAC treatment for power purchased from an affiliated QF or IPP. Five have considered the type of fuel adjustments that would be appropriate for power purchased from a QF or an IPP that wins a competitively bid power supply contract.

It was noted at the conclusion of the previous chapter detailing the results of the purchased gas adjustment clause survey that the commissions have been quite active in certain aspects and less active (or inactive) in others. That conclusion, probably not too surprisingly, applies to the FAC arena as well. The commissions are very active in fulfilling the traditional roles of regulation. The results appear to show active oversight of utility operations, pass-through of legitimate costs, and methods for handling over and undercollections, although no effort has been made by the authors to measure how effectively these procedures are working. On the other hand, as in the case of the PGA, the commissions are less active in the newer areas and issues associated with the changing market structure of the industry that they are overseeing. Thus, it appears that regulators are being cautious, waiting for the new issues to confront them before they respond. This is, of course, a legitimate course of action, albeit one that might be unsettling to those who prefer regulators to be more proactive.

CHAPTER 4

PURCHASED GAS ADJUSTMENT CLAUSES IN A MORE OPEN GAS MARKET

Gas markets are now more open than in the past. In particular, there are more supply source options so an LDC can purchase gas supplies from the pipeline or directly from the producer, or it can purchase gas on the spot market or the gas futures market. If it engages in direct gas purchase from producers, it can contract with intervening pipelines for firm or interruptible gas transportation service. In addition, many LDCs have the option of engaging in gas storage to increase service reliability and to take advantage of seasonality in the cost of gas. Thus, the gas market now has many more supply options than in the past when the LDC had only one option for gas supply, its pipeline.

Also, in most states large LDC customers have the option of purchasing gas from whatever source they choose. If they find that gas owned and supplied by the LDC too costly, they can switch to transportation service only from the LDC and purchase gas from any of the sources listed above. Thus, the gas market is more open for the LDC's customers as well as for the LDC. That certain large customers can avoid LDC gas sales service creates an incentive for the LDC to hold down the price of gas sold to those customers.

What are the regulatory implications of PGAs for ratemaking in a more open gas market? This chapter will address this question. The first section will address the incentives conveyed by a PGA to procure the lowest- and best-cost gas supply in a more competitive environment. It will also address the special problems that might arise if certain costs are included in the PGA. In particular, it will address how the inclusion of gas take-or-pay liabilities might induce a customer to switch from sales service to transportation-only service if switching would allow the customer to escape these charges. The next several sections will discuss how to design a PGA that would be appropriate in a more open market environment and examine its implications.

The Incentives Conveyed by Current PGA Practices

Local distribution companies have more supply options today than in years past. Not only do they have more supply sources (producers and brokers as well as traditional pipeline sources) to buy gas from, but they also have several markets in which to buy gas. These markets include the spot market, the futures market, the forward contract market, and the long-term market. The spot market reflects the current price of a one-month or thirty-day contract for gas. A futures contract is a contract for delivery of gas for some month up to twelve months into the future. Contracts in the futures market are standardized so that the gas contract remains fungible. The forward contract market is similar to the futures market except it varies in a few key respects. Forward contracts in the gas market are for a period in excess of one year. Also, forward contracts are not standardized but vary as to their terms, particularly the terms of delivery. Long-term contracts are of a longer term than those typical of forward contracts and can be of varying lengths. Before 1980, it was typical that long-term contracts were twenty or thirty years in length. Since then contract lengths have ranged from three to fifteen years.[1]

For the PGAs to be designed for incentive compatibility in a more open competitive environment, there must be an incentive for LDCs to act efficiently by minimizing fuel costs. To do so, there must be an incentive for the LDC to assemble a diversified portfolio of fuel inputs and to change its mix as conditions change to obtain an optimal portfolio providing reliable gas at minimal costs. (There would also need to be some mechanism to quickly pass the appropriate price signals, that is the competitive retail price, to the retail customer.)

A well-designed PGA should provide an LDC with an incentive to take advantage of price and supply variations between the spot, future, forward contract, and long-term contract markets. Otherwise, an LDC will not have an adequate incentive to minimize its costs. Current PGA practices utilize a delayed or shared-

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[1] Kevin A. Kelly et al., *State Regulatory Options for Dealing with Natural Gas Wellhead Price Deregulation* (Columbus, OH: The National Regulatory Research Institute, 1983), appendix D.

savings pass-through mechanism to create an incentive to take advantage of the opportunity of lower prices. However, as shown later, these incentives are inadequate because, for the most part, PGAs relate the selling price of gas directly to the purchase price, the incentive to pursue market opportunities that could result in savings is minimal. There is actually very little price risk to the LDC. Because of this, there is also little incentive to take advantage of market opportunities that might exist in the futures or forward contracts market.[2] Indeed, the early reports (Spring 1991) from the New York Mercantile Exchange show that nearly 90 percent of those buying gas futures contracts are marketers, while producers, end users, and speculators make up less than 5 percent each. Nearly 40 percent of those selling gas futures are gas producers, and the rest are speculators and end users.[3] No LDCs are involved in the market, perhaps because with the PGA as currently designed there is little advantage to locking in prices.[4] However, the marketing affiliates of at least one LDC not bound by a PGA is involved in futures trading.[5]

Also, there may be a poor connection between the wellhead and the burner tip, because variations in the cost of supplies will not quickly affect demand decisions and because gas retail customers will not have the appropriate price signals in a timely fashion to rationally make purchase decisions. A poorly designed PGA will not serve these functions.

However, the LDC will not have an incentive to make the linkages between markets and to pass on quickly the appropriate price signals to retail customers without a PGA. The LDC will not necessarily aggressively seek out less expensive sources of gas, because there would be little incentive to find cheaper gas since the

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[2] Edward H. Jennings, "The Use of Natural Gas Futures by Local Distribution Companies," *NRRI Quarterly Bulletin* (Columbus, OH: The National Regulatory Research Institute, forthcoming December 1991).

[3] Frank Ahrens, "Back to the Futures," *American Gas*, September 1991, 20-21.

[4] Ibid., 21-22. However, the article does not cite the current design of PGAs as a reason for LDCs non-participation. Instead, it cites convergence problems, locational biases, and commission prudence reviews as being the reasons.

[5] Ibid., 23. Again, the article makes no mention of PGAs.

cost of gas will be passed through to ratepayers at the next rate case.[6] Because of the lengthy period between rate cases, the LDC will likely pursue a gas procurement policy that minimizes the volatility of purchase gas prices. Such a strategy would tend to lead an LDC to emphasize the use of long-term contracts, even if long-term contract gas is not the cheapest and best source. Therefore, a well-designed PGA allowing the LDC to take advantage of variations between markets and to pass appropriate price signals on to customers, is preferable to no PGA at all. A well-designed PGA will also encourage an LDC to be an efficient gas procurer and will quickly pass through savings from the more efficient gas procurement to the customers, without removing the LDC's incentive to improve its gas procurement practices.

Current state commission PGA practices also might tend to discourage an LDC from reacting quickly to changing market conditions. A common state commission requirement is that an LDC have a least or best-cost gas procurement plan reviewed or approved by the commission.[7] Such a requirement would encourage an LDC to pursue the least- or best-cost gas as identified in its gas procurement plan, but would provide no encouragement (and indeed might discourage) an LDC from taking advantage of changing market conditions between plan filings. An LDC might tend to follow its plan even in view of changed conditions to avoid the possibility of a prudence review on its gas procurement.

These problems are compounded by some state commission's policies on take-or-pay charges. If these charges are included in the fuel adjustment clause as a part of the cost of gas but not included in transportation service charges, then customers with the option of fuel switching or switching to transportation-only service from the LDC will be tempted to do so. This problem is particularly pernicious for take-or-pay liabilities reflecting past costs incurred by the pipeline passed on to the LDCs as a result of FERC regulation. These charges do not reflect current costs and send the

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[6] See Daniel Duann, Robert E. Burns, Peter Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, December 1989).

[7] Ibid., 83-87.

wrong price signals to customers who then either underconsume, bypass the LDC, switch fuels, or switch to transportation service (in those states where take-or pay costs are not also included in the transportation rate). Inelastic customers with none of these choices pay too much for gas.

What is needed is a purchase gas adjustment clause that solves the problems laid out above. What follows in the rest of this chapter is a description and illustration of how such a purchase gas adjustment clause might be designed. It is not our intent to propose a PGA clause that can be directly applied by regulators in their states. Instead, our objective is to e amine potentially desirable features and concepts that state regulators could consider in view of today's more open gas market.

The Fixed-Weight PGA

As noted earlier, LDCs have more supply options today than in the past. Besides the traditional long-term gas market, there are growing spot, forward, and futures markets. LDCs now can buy gas directly from producers or indirectly through brokers. Arguably, LDCs have not responded optimally to changing conditions, relying too much on "tried-and-true" ways of doing business. In many ways, PGAs have made supply reliability more crucial than price to LDCs and in so doing may have inhibited optimal decisionmaking. The purpose of the fixed-weight (FW) PGA is to help remove such inhibitions in ways that benefit the LDCs, and ultimately the ratepayers.

The FW PGA is predicated on the belief that rewards are critical in shaping behavior that requires extra effort by an LDC's management. For LDCs, as for any businesses, the strongest reward is one that directly affects profits. At the same time, a properly functioning PGA must convey correct price signals to ratepayers. Retail prices should reflect the minimum average cost of available gas supplies as well as adjust quickly to changes in market conditions. The FW PGA is designed to adjust retail rates quickly and encourage both consumption and managerial efficiency.

The Basic Design

The FW PGA is essentially a process for gas cost recovery with the major objective of giving LDCs an incentive to respond more efficiently to changes in the price of gas from different sources. The fixed weights come in two varieties: market weights and supplier weights. The market weights measure the contribution of each market--long-term, spot, forward, and futures--to total supply. Consequently, the weights are proportions that together sum to one. Within each market are suppliers whose weights sum to one. A supplier's weight measures its contribution to a particular market's supply. Figure 4-1 diagrams how market and supplier weights combine to form an LDC supply portfolio. Although a unique market-supplier relationship is shown, an LDC could have multiple contracts with a particular supplier that spans several markets.

In Figure 4-1, the long-term market accounts for 60 percent of total gas supplies (and is assigned a 0.6 weight). The futures market, on the other hand, provides 10 percent of the LDC supply needs, and therefore, receives a 0.1 weight. Supplier A has a weight of 0.3 because it provides 30 percent of long-term supplies which, as stated, accounts for 60 percent of total supplies. Supplier A's share of total supplies is 18 percent, which is the product (market weight) x (supplier weight) x (100 percent) or (.3)(.6)(100%). As Figure 4-1 shows, the market weights sum to one and within each market the supplier weights sum to one.

The weighted cost of gas (WCOG) is simply computed as a weighted average cost of the different sources of gas supplies. Using the following formula, where the Ps denote supplier prices and the decimals denote market and supplier weights, WCOG equals[8]

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[8] The general formula is given as $\sum_{i=1}^{n} \sum_{j=1}^{m} \alpha_i \beta_{iJ} P_J$ where i is over markets, j over suppliers, and α and β are the corresponding market and supplier weights.

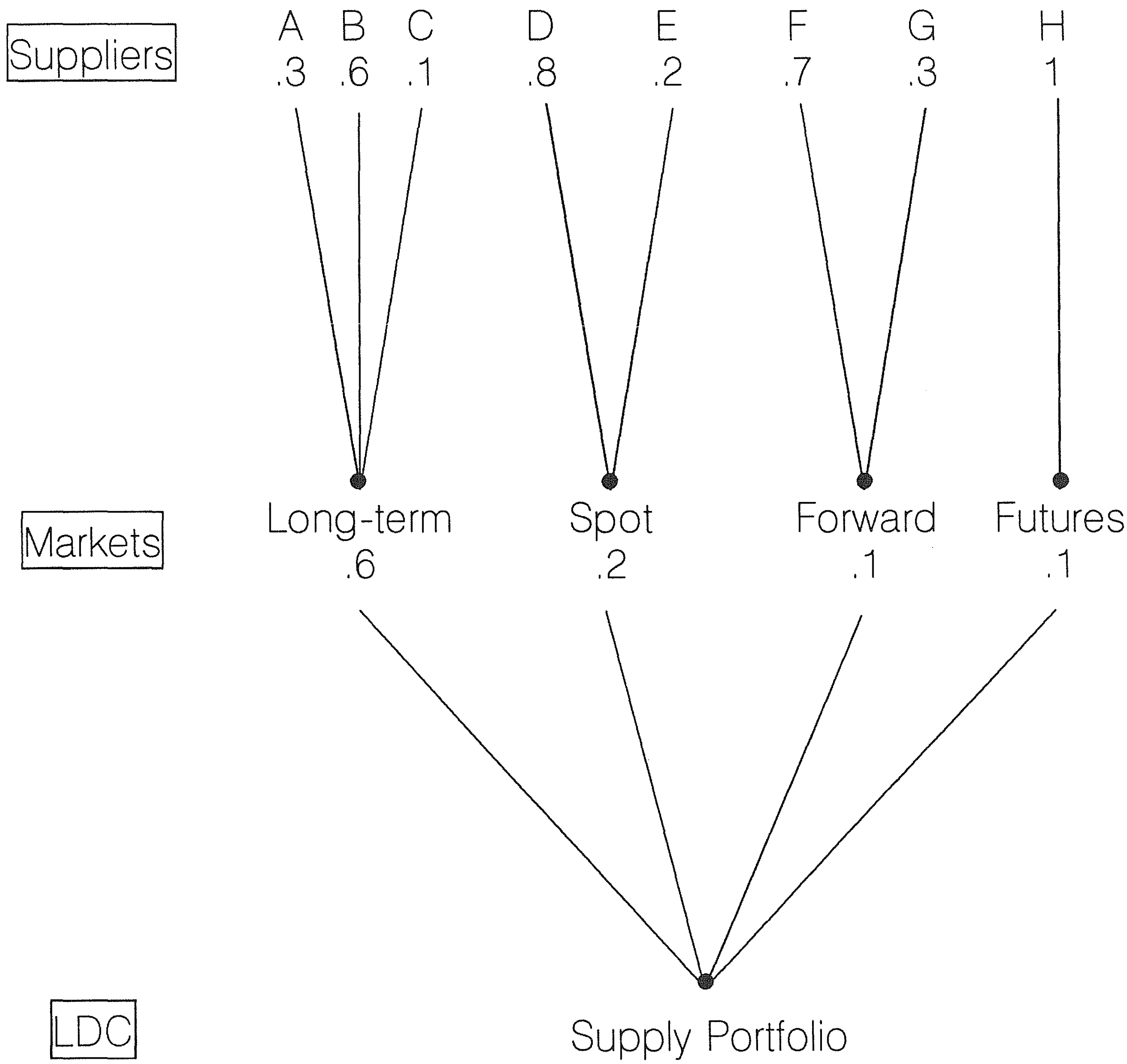

Fig. 4-1. A representative supply portfolio with fixed weights.

$$
\begin{aligned}
WCOG = &.6[.3P_A + .6P_B + .1P_C] && \text{(long-term market)}\\
&+ .2[.8P_D + .2P_E] && \text{(spot market)}\\
&+ .1[.7P_F + .3P_G] && \text{(forward market)}\\
&+ .1[1P_H] && \text{(futures market).}
\end{aligned}
$$

Changes in WCOG can be computed easily when price changes are known. Assume as an example a 10 percent increase in the price of supplier A: the percentage increase in WCOG equals the product (market weight) x (supplier weight) x (percentage increase), which in the above formula equals (.3)(.6)(10%) or 1.8 percent. As discussed below, changes in gas supply prices should be factored into WCOG fairly quickly to reflect changes in purchased gas costs in demand markets.

Once the market and supplier weights are set jointly by the commission and LDC, the LDC can make any purchase decision it chooses; it is not restricted to purchase according to the fixed weights. As prices for gas supplies fluctuate, the LDC can purchase supplies in relative quantities that differ from those incorporated into the FW PGA allowing the actual cost of gas (ACOG) to deviate from the WCOG. But, to encourage LDCs to seek the optimal portfolio requires that they retain permanently a share of the cost savings from efficient gas portfolio management. The basic incentive mechanism behind the FW PGA is setting a supply portfolio target from which the LDC would have an incentive to "beat" the target by allowing it and the ratepayers to share in the cost savings from optimal decisionmaking. The target is the WCOG determined by the predetermined "fixed" weights and actual prices. As prices change the target changes to reflect the current market realities. The fixed weights become suboptimal, whenever prices fail to change proportionally, that is, a lower-cost portfolio offering the same level of reliability is attainable. The FW PGA rewards LDCs for seeking a more optimal supply portfolio which is commonly defined as one which minimizes the cost of attaining a specified level of reliability. Although the examples that follow focus primarily on cost-reducing adjustments, a discussion on integrating reliability into the FW PGA is presented.

The Retail Cost of Gas

The retail cost of gas (RCOG) is neither the actual cost (ACOG) nor the weighted cost (WCOG), but rather lies in between. Its exact position depends on the sharing rule (τ), that is, the amount the utility permanently retains. Its formula is as follows:

$$RCOG = ACOG + \tau(WCOG - ACOG).$$

The retail gas cost, that is the base cost to ratepayers, equals the actual cost plus the share, τ, of cost savings kept by the LDC. The final term of the formula measures the profit to the LDC for reducing supply cost, and therefore, is the incentive mechanism in the FW PGA. A more complete discussion on the application of the RCOG formula follows several examples illustrating the mechanics of the FW PGA.

Market-Weights: Example One

For simplicity, this example covers the effect of changing market weights on costs. A second example will present weights for individual gas suppliers. Table 4-1 illustrates the first example by disclosing the supply weights of each market, gas supply prices per thousand cubic feet (Mcf), and the calculation of the weighted cost of gas (WCOG). As Table 4-1 shows, the initial price is $1.94 per Mcf with the long-term market supplying 60 percent of total gas supplies.

Table 4-2 depicts the purchasing activity of our representative LDC during three consecutive time periods. The table lists the amounts purchased from each supply market (long-term, spot, forward, and futures) with prices in parentheses. The totals by period and market also are listed. This information along with the fixed weights from Table 4-1 are applied to compute the entries of Table 4-3. Table 4-3 gives the WCOG, ACOG, RCOG, cost saving, and LDC profits. The share of saving permanently kept by the LDC (τ) is one-third by assumption.

TABLE 4-1

INITIAL MARKET DATA FOR FW PGA EXAMPLE

Markets		Long-Term		Spot		Forward		Futures
Weights		.6		.2		.2		0
Gas Supply Prices $/Mcf		2.10		1.60		1.80		1.70
WGC $/Mcf	1.94 =	(2.10)(.6)	+	(1.60)(.2)	+	(1.80)(.2)	+	(1.70)(0)

TABLE 4-2

GAS PURCHASES AND AVERAGE MARKET PRICES
BY MARKET AND PERIOD

	Markets[1]				
Period	Long-Term	Spot	Forward	Futures	Total
1	160 (2.10)	80 (1.60)	80 (1.80)	10 (1.70)	330
2	210 (2.00)	120 (1.20)	60 (1.80)	20 (1.50)	410
3	110 (2.30)	160 (1.20)	40 (1.80)	40 (1.20)	350
Total	480	360	180	70	1,090

[1]The amounts are in thousands of Mcf with prices per Mcf in parentheses.

TABLE 4-3

WCOG, ACOG, RCOG, COST SAVING AND LDC PROFIT

Period	WCOG ($/Mcf)	ACOG ($/Mcf)	RCOG ($/Mcf)	Cost Saving ($)	LDC Profit ($)
1	1.94	1.90	1.91	15,000	5,000
2	1.80	1.71	1.74	36,000	12,000
3	1.98	1.60	1.72	128,000	43,000

As shown in Table 4-2, gas purchases vary by market and period. The variation across periods illustrates the responsiveness of the LDC to changes in its retail demand. Period 2, for example, may represent a seasonal peak period whereas periods 1 and 3 could be considered offpeak or midpeak periods. The variation across markets shows the responsiveness of the LDC to changes in the market price of gas supplies. For instance, the long-term market accounts for 60 percent of sales initially but less than one-third of sales by period 3. This change occurs because of relatively cheaper gas supplies from other markets over time.

The WCOG in period 1 is the same as calculated in Table 4-1 because market prices have remained the same even though purchase decisions have changed as evidenced by the futures market. As Table 4-3 shows, cost saving in period 1 is $15,000 with one-third--$5,000--kept by the LDC. This occurs because the LDC has replaced relatively expensive long-term supplies with cheaper supplies from other markets. The actual market weights based on actual purchases are .49, .24, .24, and .03, respectively, which differ from the initial weights used to compute WCOG.

In period 2, WCOG drops to $1.80 per Mcf, which is computed as the weighted average of the second-period gas supply prices using the initial fixed weights. The actual computation is given as: (2.00)(.6)+(1.20)(.2)+(1.80)(.2)+(1.50)(0) where the first number in each product is the price and the second is the initial market weight. The total cost based on WCOG is $738,000 whereas actual cost is only $702,000 for a total saving of $36,000. The ACOG is $1.71/Mcf obtained by dividing actual total cost by total purchases. The RCOG is only $1.74/Mcf, using the formula with τ at one-third, saving ratepayers $24,000.

In period 3, WCOG rises to $1.98 per Mcf largely because of the increase in the average price of long-term supplies; however, ACOG is only $1.60/Mcf and RCOG is only $1.73/Mcf. Cost savings are $128,000 with $43,000 kept permanently by the LDC. Table 4-4 shows the period-by-period divergence of actual supply weights from those initially set.

Supplier Weights: Example Two

As an LDC contracts and recontracts for gas supplies in response to changing prices, the amounts purchased from individual suppliers should change likewise. In practice, long-standing suppliers may be relieved and replaced by newcomers offering better price and nonprice arrangements for gas supplies. The present example examines changes of this type (for example, changing amounts and changing suppliers), and how they can be incorporated into the FW PGA. The format is the same as in the previous example except focus is upon individual suppliers rather than gas markets. For simplicity, nonprice factors are assumed comparable and constant across long-term suppliers.

Table 4-5 shows the initial-period relative contribution of suppliers A through D, their prices, and the calculation of WCOG for the long-term gas market. Table 4-6 displays a three-period illustration wherein the prices, amounts purchased, identity of suppliers, and amount of long-term purchases change over time. The variation in purchases from individual suppliers illustrates the LDC's attempt to lower costs in response to changes in their relative prices.

TABLE 4-4

DIVERGENCE IN ACTUAL MARKET WEIGHTS
FROM THOSE INITIALLY SET

Markets	Long-Term	Spot	Forward	Futures
Period		Weights		
Initial	.60	.20	.20	0
1	.49	.24	.24	.03
2	.51	.29	.15	.05
3	.31	.46	.11	.11

TABLE 4-5

INITIAL SUPPLIER INFORMATION FOR
LONG-TERM NATURAL GAS MARKET

Supplier			A		B		C		D
Weight			.6		.4		0		0
Prices ($/Mcf)			2.10		2.10		2.30		2.40
Long-term WCOG	2.10	=	(2.10)(.6)	+	(2.10)(.4)	+	(2.30)(0)	+	(2.40)(0)

TABLE 4-6

LONG-TERM PRICES AND PURCHASES BY SUPPLIER AND PERIOD

	Supplier[1]				
Period	A	B	C	D	Total
1	70 (2.10)	60 (2.10)	30 (2.00)	0 (2.40)	160
2	70 (2.00)	60 (2.00)	40 (2.00)	40 (1.90)	210
3	30 (2.30)	20 (2.30)	30 (2.20)	30 (2.20)	110
Total	170	140	100	70	480

[1]Amounts are in thousands of Mcf with prices per Mcf in parentheses.

Table 4-7 summarizes the WCOG, ACOG, RCOG, cost saving, and LDC profit. As shown, the LDC earns a profit in each period by shifting purchases away from higher-priced suppliers and toward lower-priced ones: the expected response of an efficiently managed LDC.[9] It should be noted that in period 1 the lowest-cost alternative for the LDC would be to purchase all of its long-term supplies from supplier C; the example assumes, however, minimum-take provisions and other constraints exist that limit portfolio adjustments. The long-term WCOG is computed in each period using the initial supplier weights in Table 4-5. As in the previous example, the deviations in WCOG and ACOG are due to deviations between actual

[9] This assumes reliability is above minimum acceptable levels.

TABLE 4-7

WCOG, ACOG, RCOG, COST SAVING, AND
LDC PROFIT BY PERIOD

Period	WCOG	ACOG	RCOG	Cost Saving	LDC Profit[1]
1	2.10	2.08	2.089	$3,200	$1,067
2	2.00	1.98	1.987	$4,200	$1,400
3	2.30	2.22	2.247	$8,800	$2,933

[1]Assumes the LDC retains one-third of cost savings as profit.

and fixed weights. By period 1, for example, the initial weights of (.6, .4, 0, 0) for suppliers A through D have already changed to (.44, .37, .19, 0) as the LDC attempts to lower portfolio cost by efficiently adjusting its purchases toward lower-cost supplies. By period 3, suppliers C and D are shown to be cheaper than either A or B with actual supply weights becoming (.27, .18, .27, .27), reflecting a continued shift toward gas suppliers with relatively lower prices.

In sum, the second example shows how the FW PGA accounts for an LDC changing gas suppliers and amounts purchased from individual suppliers. It shows that an LDC would have an incentive to switch suppliers when gas prices from individual suppliers change. Switching allows LDCs to earn profits while at the same time benefits consumers with lower cost gas. By period 3, the cost saving totals $16,200 with the LDC earning $5,400 in profit. Even though the cost to ratepayers exceeds actual cost in all periods, due to LDC profits, cost are $10,800 less.

The above example is kept simple because it assumes (1) reliability remains constant, (2) price changes occur simultaneously, and (3) no initial supplier is dropped. When an initial supplier is dramatically reduced or dropped, a commission can have the LDC compute WCOG by (1) using the price data from remaining initial suppliers only, (2) using price data of a new supplier along with that of initial suppliers, or (3) holding a reconciliation review to evaluate the initial portfolio. The workings of a reconciliation review are discussed more fully in the chapter.

Sequential Purchases

The WCOG changes whenever the prices of initial suppliers change. The above example assumed price changes occurred simultaneously at the beginning of each period; however, this outcome is unlikely. It is more likely for prices to change sequentially. In fact, the FW PGA should foster such change: shifting purchases to suppliers with better terms will pressure others to do likewise.

As prices change and new amounts are purchased, the WCOG of current purchases will differ from its previous value. The WCOG should use actual prices, not expected ones, and apply solely to supplies purchased at those prices. To clarify this, Table 4-8 contains sequential price and supply data occurring in a single period for two suppliers A and B. The example assumes each supplier has a weight of one-half.

The table contains two purchase schedules and their respective cost schedules. Although total amounts are the same, the schedules differ in the timing of purchases. Schedule 1 (S1) has the LDC purchasing most of its supplies when WCOG is at its lowest value whereas Schedule 2 depicts the opposite. The cost schedules are derived by multiplying actual purchases by the concurrent WCOG. Even though the cost schedules are derived using the same WCOG sequence, total costs differ again due to the timing difference in purchases. The key task, therefore, is transforming a "sequence" of WCOGs and purchase decisions into a single-valued "period" WCOG.

When the price of supplier A decreases to $2.50/Mcf, WCOG drops from its initial value to $2.25/Mcf and then again to $2.20/Mcf as the price of B drops. In all, there are three values for WCOG during the period, each associated with a unique level of purchases. The "period" WCOG is given as the weighted-average of "sequential" WCOGs with amounts purchased determining the weights. The weight of

TABLE 4-8

SEQUENTIAL PRICE AND SUPPLY DATA FOR SUPPLIERS A AND B

			Purchase Schedules		Cost Schedules	
Price A ($/Mcf)	Price B ($/Mcf)	WCOG[1] ($/Mcf)	S1 (Mcf)	S2 (Mcf)	C1 ($)	C2 ($)
3.00	2.00	2.50	13,000	35,000	32,500	87,000
2.50	2.00	2.25	12,000	12,000	27,000	27,000
2.50	1.90	2.20	35,000	13,000	77,000	28,000
			60,000	60,000	136,500	142,600

[1]Assumes supplier weights are one-half.

a particular WCOG in the sequence is given as the amount purchased at that cost divided by total purchases.

As the above implies, the period WCOG depends upon the purchase schedule. If Schedule 1 characterizes the LDC's purchase decisions then period WCOG is \$2.275/Mcf, whereas, under Schedule 2, period WCOG would be \$2.376/Mcf.[10] As should be obvious, computing sequential WCOG and period WCOG requires additional effort which increases the cost of regulation. But the information needed to compute WCOG is the same needed to compute ACOG which is done routinely at commissions. The additional regulatory cost, therefore, should be minimal although the benefit to ratepayers could be substantial.

[10] For Schedule 1, period WCOG = \$136,500/60,000 Mcf = \$2.275/Mcf. For Schedule 2, period WCOG = \$142,600/60,000 Mcf = \$2.376/Mcf.

Customer Billing

A good billing mechanism should (1) encourage consumption efficiency, (2) recover all prudent costs, and (3) reward managerial efficiency. Consumption efficiency requires the rewards to managerial efficiency be separate from retail rates and appear as a surcharge on customer bills. Ideally, retail rates should be marginal-cost based; however, such a pricing rule is not applicable to the natural gas industry.

Suppose an LDC has two suppliers who charge $4/Mcf and $2/Mcf, respectively. Suppose average cost is $3/Mcf. A relevant question is what is marginal cost: $4/Mcf or $2/Mcf? If marginal cost and rates are assumed to be $2/Mcf then the LDC fails to recover its gas costs; on the other hand, at $4/Mcf the LDC earns a profit. If marginal cost is the cost of the last purchase, then an LDC would maximize profits by paying a high price for the last unit and a low price on all prior purchases. Needless to say, this is not desirable portfolio management.

A good billing candidate is the RCOG formula introduced earlier since it separates the actual cost of gas from the cost saving retained permanently by the LDC. The actual cost of gas (ACOG) is an average, not marginal, cost and should become the base retail rate to ensure full cost recovery. The reward--τ(WCOG - ACOG)--should appear as a surcharge, perhaps subsumed in the customer charge, to help minimize consumption inefficiency.[11] Thus, the RCOG formula could be rewritten as: RCOG = Base Retail Rate + Surcharge.

Since surcharges are nondistortionary to consumption decisions, commissions can embed regulatory goals within surcharge collection schemes. A uniform surcharge on customers would benefit large customers and help maintain system load. Exempting low-income households, on the other hand, may promote greater social equity. Of course, many collection schemes could be devised to favor some group without being

[11] By adding the reward to the base retail rate, the rate will overstate the actual cost of gas and potentially cause underconsumption.

labeled a subsidy.[12] As long as the amounts paid individually are below the WCOG, all customers benefit regardless if some pay a higher surcharge.

Supply Reliability

Reliability was kept latent in the above examples by keeping it constant and comparable across suppliers, markets, and time. The examples dealt primarily with minimizing portfolio cost. Although "optimal portfolio" is definable in various ways, it commonly refers to the portfolio of lowest cost that meets some prespecified level of reliability. Sometimes reliability is easy to assess, other times it is not, making likewise commission efforts to monitor its level and movement. Both situations are discussed in this section with the difficulty of assessment emphasized most.

Easy to Assess

When reliability is easy to assess, judgments on LDC performance will likewise be easy. Commissions can monitor supplier and market weights, assess reliability and cost, and order changes when necessary. The primary task would be deciding what level of reliability is optimal and what factors should cause it to change. Unfortunately, reliability assessment is seldom this simple inducing commissions to rely on alternative ways to monitor and control reliability.

Difficult to Assess

Although LDCs are responsible for system reliability, commissions need instruments to infer its changes and ensure its adequacy. One approach to assure adequacy yet avoid the complexity of measurement is to restrict the market weights and assign minimum values to some. Another approach is to devise instruments indicative of reliability and use them to assess managerial decisions. The first

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[12] A subsidy implies one groups gain is another's loss.

approach is authoritative which can hinder managerial efficiency although it is simple to implement and can be responsive in design. The second is more responsive in style, offering greater managerial discretion, but exposing ratepayers to more risk.

Market-Weight Restrictions

The markets differ contractually both in the type of commitments made and in how readjustments proceed. The long-term contract typically involves committed reserves, price adjustment clauses, designated protocol for disputes, and other stipulations making supply reliable. The futures contract, by contrast, offers no committed reserves dispute protocol nor stipulations tailored to the needs of ratepayers. It simply states the price, amount, date, and point of delivery. Although delivery is likely, futures contracts do not afford long-term, reliably stable prices stability. Spot market and forward contracts fall in between with spot contracts akin to long-term ones and forward contracts similar to those in the futures market.

The market most important for reliability is the long-term market since it entails the highest degree of contractual commitment. Commissions can simplify their control over reliability by setting a minimum value for the long-term market weight. The minimum value need not be fixed but instead could vary and be responsive to market conditions. The following equation is an example of such in which the long-term market weight (α) adjusts to seasonal changes (S) in demand: $\alpha_1 = \alpha_0 + \beta S$. The variable S could take the value "1" during peak months and "0" otherwise making the adjustment coefficient (β) positive. The example is purely heuristic and more elaborate models could be designed.

Reliability and Prices

Natural gas is largely homogenous but suppliers and markets are not. When markets are in equilibrium, price differences among suppliers reflect reliability differences. A high "relative price" should indicate a supply offering greater reliability than those with lower prices.[13] When the reliability of a supplier rises, its supply becomes more valuable and relatively more expensive. This implies that when LDCs shift toward higher-priced supplies their portfolio should become more reliable.[14]

Besides relative prices, changes in "real prices" have reliability implications also. Real prices adjusted for inflation or deflation. As natural gas becomes more scarce due to aggregate supply decreases or demand increases, its price rises. As scarcity heightens reliability diminishes since scarcity defines the upper limit to reliability. Consequently, rising real prices indicate a lowering of total reliability.

The above paragraphs are not contradictory because they reference different price concepts. The first paragraph concerns "relative prices" which are meaningful only when "real prices" are in equilibrium with unchanged levels of aggregate supply and demand. The second paragraph concerns "real prices" which only change when either aggregate supply or demand changes. Relative prices, therefore, indicate reliability when the aggregate market is "in equilibrium" whereas real prices indicate reliability changes when the market shifts its equilibrium. By combining both price concepts, a price index indicative of reliability change can be obtained.

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[13] This claim follows from the efficiency condition for an optimal portfolio; essentially, $(R_i/P_i) = (R_j/P_j)$ for all i and j where R measures reliability, P denotes price, and i and j are suppliers. The ratios (R/P) measure the marginal cost of reliability across suppliers. The condition for an optimal portfolio is that the marginal cost of reliability is equalized across suppliers. This further implies if $P_i > P_j$ then $R_i > R_j$. The efficiency condition enables a comparison of supplier reliability whenever actual levels are hard to assess; namely, price ratios indicate relative reliability. If $P_i = \$3.00/\text{Mcf}$ and $P_j = \$2.70/\text{Mcf}$ then $(R_j/R_i) = 0.9$ suggesting supplier "i" is 10 percent more reliable.

[14] Overall, portfolio reliability depends upon the actual mix of high and low reliability suppliers. From Footnote 11, higher prices indicate higher levels of reliability.

The Reliability-Price Index

The Reliability-Price Index (RPI) is defined as follows: RPI = (P_0/P_t) x $(ACOG_t/WCOG_t)$. The first term accounts for real price changes and the second term measures relative changes. The index is interpreted as follows:

	< 1		less reliable
When RPI is	= 1	the portfolio is	unchanged
	> 1		more reliable.

When the current real price (P_t) is below the initial period price (P_0), reliability is deemed higher.[15] The commissions can utilize regional or national price indices to model changes in real prices over time. National data are preferable since they represent the entire gas market and are appropriate unless regional and national trends fail to coincide. Indices reported on a monthly or quarterly basis are preferable to those of longer duration since they offer greater accuracy and frequency of portfolio assessment.

The term $(ACOG_t/WCOG_t)$ indicates the current portfolio's relative reliability. Recall, both $ACOG_t$ and $WCOG_t$ incorporate the same price information but actual and fixed weights can deviate causing final values to differ. The value of $ACOG_t$ falls below $WCOG_t$ whenever lower-cost supplies are purchased in proportions greater than their fixed weights. Such decisions make the ratio $(ACOG_t/WCOG_t)$ less than one in value and reduce the reliability index.

The index can be generalized to enable real and relative price changes to affect reliability unequally. The formula RPI = $(P_o/P_t)^\alpha$ $(ACOG_t/WCOG_t)$ with $\alpha \geq 0$ is one such generalization. When α is between 0 and 1, say 1/2 for example, relative prices will more strongly impact the reliability index than real ones. Conversely, values of α larger than 1 make real price changes more affecting.

[15] A lower current price indicates either market demand has contracted relative to supply or market supply has expanded relative to demand. Both imply a higher availability of gas indicating higher reliability.

The Consumer Welfare Index

The Consumer Welfare Index (CWI) combines reliability and cost saving to infer ratepayer well-being. The index is just one of many possible approaches to assess the net impact of portfolio changes. Essentially, it is a weighted average of change--with the weights commission-set--and is given as follows: CWI = σRPI + (1 - σ) CSI. The term CSI is the cost-savings index defined as the ratio ($WCOG_t/RCOG_t$).

The interpretation of CWI is similar to RPI with values above one indicating higher levels of consumer welfare and those below one indicating the opposite. When LDCs shift to lower-priced supplies, for example, the RPI drops below one whereas CSI climbs above one to the extent WCOG exceeds RCOG. The net effect on consumer welfare depends upon the relative importance of reliability and cost saving as determined by the commission. As the value of reliability grows, the value of σ approaches one. Suppose the shift to lower-priced supplies causes RPI to be 0.93 and CSI to be 1.09. The value of CWI when σ = 1/2 (equal importance) is 1.02 whereas it becomes 0.98 when σ = 2/3 and reliability is considered twice as important.[16]

By adjusting the weights systematically a commission can redirect the efforts of an LDC. When gas supplies seem plentiful and highly reliable, a commission could lower σ and increase the importance of cost saving in the CWI equation. Then again, when periods of high demand are fast approaching, a commission could raise σ and signal LDCs to emphasize supply reliability.

The instruments offered are designed to help commissions monitor and affect LDC decisionmaking but are based primarily on price information. Commissions, therefore, will need additional information to fully and correctly assess the reliability and welfare consequences of portfolio adjustments. One way to obtain timely information is to set a lower boundary on RPI or CWI and require an LDC to justify

[16] When σ = 2/3 the weight of CSI is 1/3 implying reliability is considered twice as important as cost saving to consumer welfare.

its decisions whenever the index falls below this value. This should help commissions stay abreast of changing market or supplier conditions and hinder inefficient portfolio management by LDCs.

The Sharing of Cost Savings

Total cost saving is defined as the difference between WCOG and ACOG multiplied by the amounts purchased. The fraction τ kept permanently by the LDC is its profit incentive to outperform the initial supply portfolio. Consequently, the fraction selected will strongly affect LDC conduct and performance. Unfortunately, there are no precise guidelines to determine the optimal value of τ partly because it depends upon the idiosyncrasies of LDCs. General guidelines can be established, however, to narrow the range of possibilities.

The fraction of savings kept by LDCs must be sufficiently high to encourage participation but not so high as to distort LDC decisionmaking on the margin. The opportunity cost of greater reliability to an LDC is the foregone profit it could earn from securing relatively cheaper but less reliable supplies of gas. High fractions of τ, those close to one, raise the opportunity cost of reliability and could result in a suboptimal portfolio from the perspective of ratepayers. However, lowering reliability to earn a profit increases the risk to LDCs of incurring political and social costs from not meeting customer demand. Thus, the extent of inefficiency from a too high value of τ is limited by the magnitude of political and social ramifications.

Another consideration concerns the primary goal of the FW PGA which is to benefit ratepayers. The share of savings to ratepayers must be sufficiently large for there to be meaningful welfare improvements. The value of τ must be politically palatable which is unlikely when ratepayers receive a smaller share than the LDCs. Consequently, the upper limit of τ should be around one-half.

Transaction Costs

The process of monitoring supply prices, contracting, and recontracting is not a costless endeavor. The LDC will need to expend resources and incur transaction costs to improve upon its initial supply portfolio. The accounting of transaction costs affects the overall performance of the FW PGA. The efficient treatment is to include them in the profit equation and thereby induce LDCs to control their levels. The average profit to LDCs would become τ(WCOG - ACOG - TC) where TC denotes transaction cost. For given values of WCOG and ACOG, the LDC can increase its profit only by lowering transaction costs.

The additional transaction cost from implementing the FW PGA should be minimal since LDCs already have well-established procurement departments. Thus, the majority of needed investment has already been made making additional cost primarily variable and controllable.

Retail Rates

Besides profits, retail rates must be adjusted for transaction costs. How this occurs depends upon the general accounting practices of the LDC and any commission rules governing them. Ultimately, the cost should be apportioned to the LDC and ratepayers in amounts determined by τ.

The RCOG formula after modified by transaction cost becomes:

$$\text{RCOG} = \text{ACOG} + \text{TC} + \tau(\text{WCOG} - \text{ACOG} - \text{TC}),$$

which reworked becomes:

$$\text{RCOG} = \text{ACOG} + (1 - \tau)\text{TC} + \tau(\text{WCOG} - \text{ACOG}).$$

The difference between the modified and unmodified version is $(1 - \tau)$TC which enters the ratepayer base retail rate. The conditions for efficiency, therefore, are to apportion the transaction cost and cost saving proportionately, and to place transaction cost in the gas rate not the surcharge.[17]

Reliability and Welfare Indices

Although transaction cost should be low, both ACOG and RCOG will be higher as a result. The reliability index depends on the value of ACOG whereas the welfare index depends upon both. A key question is whether to include transaction cost in the reliability and welfare indices. The answer is to include them in the welfare index but not the reliability index; or put differently, add them to RCOG but not to ACOG.

The inclusion of transaction costs will bias upward estimates of reliability which makes those estimates a candidate for manipulation. An LDC could, for example, overstate transaction costs to raise estimates of reliability purposely to avoid commission scrutiny of recent portfolio decisions. Reliability would appear better because the ratio ($ACOG_t/WCOG_t$) becomes larger when transaction cost is added to the numerator $ACOG_t$. Of course, this problem disappears by excluding transaction cost from the reliability index.

Including transaction costs in the welfare index is appropriate since ratepayers cover some of the expense.[18] The welfare index can be corrected by using the modified RCOG formula to compute the cost saving index which together with the reliability index forms the welfare index. An increase in transaction cost raises RCOG which lowers the value of the cost savings index. Since reliability is kept unaffected, higher transaction costs lower the estimate of consumer welfare which works against the LDC since it might elicit commission concern. Thus, correctly modifying the indices will further encourage LDCs to control transaction costs and correctly report their amount.

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[17] Recall that LDCs keep τ ($ cost saving) implying ratepayers are receiving $(1 - \tau)$($ cost saving). Hence, transaction costs and savings are apportioned proportionately.

[18] Ratepayers cover $(1 - \tau)$TC in their base retail rate.

Profit-Share Adjustors

A profit rate adjustor is simply a formula to govern changes in the value of τ, the profit share. By adjusting τ strategically, commissions can guide LDC efforts toward objectives deemed in the public interest. For instance, τ could be linked to the level of system demand; in particular, τ could decrease as demand increases. This adjustor causes LDCs to prefer reliability over cost saving when system demand rises and prefer the converse when it falls.[19] Naturally, more advanced adjustors enabling greater control over LDC decisionmaking could be designed, but to be efficient the adjustor must exhibit certain characteristics. An efficient adjustor must (1) convey clearly commission goals to LDCs, (2) tie future profits to current decisions, and (3) be formalized clearly so LDCs can predict the consequence of their actions.

The CWI-Adjustor

The CWI-adjustor, as the name suggests, links the value of τ to the consumer welfare index and can be formalized as $\tau = f(\text{CWI})$. The function f should be characterized so that increases in CWI raise τ and decreases lower it. The specific form of $f(\cdot)$ however, should be tailored by commissions to fit the idiosyncrasies of LDCs.

The CWI combines both the reliability and cost saving indices using weights set by the commission. So by changing the weights purposefully, a commission can use CWI to adjust τ and redirect the purchase decisions of LDCs. Suppose reliability is considered too low given current supply portfolios. A commission could alter this by raising the weight to the reliability index in CWI which lowers its value and

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[19] As τ falls, the opportunity cost of reliability decreases on the margin. Put differently, as τ falls marginal profit falls making the portfolio too risky given the lower profit rate.

consequently the value of τ.[20] A lower value of τ lowers the opportunity cost of reliability which encourages LDCs to purchase more reliable supplies of gas.[21] Of course, by adjusting upward the weight to the cost saving index, a commission could obtain the opposite result and encourage LDCs to pursue lower-cost supplies.

The CWI-adjustor ties future values of τ to current LDC decisions, and with $f(\cdot)$ specified, allows LDCs to predict the consequence of particular options. By determining the change in CWI, an LDC can use the CWI-adjustor to predict the effect on τ from pursuing a particular purchasing strategy. This allows LDCs to simulate various portfolio configurations and select those with the best profit-to-reliability characteristics given the commission's valuation of reliability and cost saving. The net result should be an improvement in efficiency since LDCs will be aware of commission goals and the implications of changing ones.

In addition to relative prices, real price changes would affect LDC purchase decisions also. Real prices enter the CWI and therefore the adjustor through the reliability index. An increase in the national price, for instance, would lower CWI causing τ to drop via the adjustor, thereby encouraging LDCs to pursue more reliable supplies of gas. The decrease in τ depends upon the functional form of $f(\cdot)$ and the weights in CWI, both determined by the commission.

The CWI-adjustor considers both real and relative prices, fixed and actual weights, and reliability and cost-saving weights to adjust the profit share. Consequently, adjustments are drawn from the actions and decisions of suppliers, LDCs, and commissions.

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[20] When reliability is low the value of RPI is below one whereas CSI is likely above one. By weighting RPI higher, and consequently, CSI lower, the value of CWI drops causing τ to do the same.

[21] As τ decreases, the profit-to-risk ratio becomes uneconomical. The LDC must reduce portfolio risk by shifting purchases toward more reliable suppliers until it obtains a desired profit-to-risk portfolio.

The Reconciliation Review

The reconciliation review functions primarily to update portfolio weights and to share information. The frequency will depend partly on the style of commission regulation and partly on changes in economic circumstances. The complexity will vary, sometimes commanding few resources and little time and sometimes becoming quite involved. Their occurrence may be due to commission initiative or that of the LDC.

Review Frequency

In general, a reconciliation review should convene whenever (1) a rate case occurs, (2) LDC losses occur, or (3) important suppliers are dropped or added.

The rate case develops rate schedules based upon anticipated cost and the LDC's revenue requirements. An optimal rate schedule can unfold only after cost expectations and reliability considerations have shaped a new set of fixed weights. Therefore, efficiency requires an evaluation of an LDC's supply portfolio during the rate case to ensure its appropriateness.

A loss occurs to an LDC whenever the actual cost of gas exceeds its weighted cost. Some of the loss is passed on to ratepayers in the form of higher retail rates, the increase dependent on τ.[22] Actual cost will exceed weighted cost when higher-priced supplies are purchased in amounts exceeding their fixed weights. The problem is not one of price since both actual and weighted cost incorporate the same price information; instead, the problem stems from supply selection. The reasons for such selections are, of course, critical to the treatment of losses but the need for correction is imperative nonetheless and requires a reconciliation review.

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[22] Let ACOG exceed WCOG by the amount K, hence, WCOG - ACOG = K< 0. The RCOG formula becomes: RCOG = ACOG + τ(WCOG - ACOG) or RCOG = ACOG - τK. The loss to the LDC is τK. Since ACOG = WCOG - K by assumption, RCOG = WCOG + (1 - τ)K implying (1 - τ)K is passed onto ratepayers in the form of higher retail prices.

When large suppliers are added or dropped it is good policy to hold a reconciliation review and update the fixed weights. A reconciliation would give commissions the needed time to collect information on all suppliers so to better assess the appropriateness of LDC selections. The policy helps protect ratepayers against harmful self-dealing arrangements; for example, an LDC could drop a large reliable supplier deliberately to add a high-priced affiliate.[23]

LDC-Initiated Reviews

Besides commissions, LDCs have reasons to request a reconciliation review. One reason touched on above is when LDCs purchase higher-priced supplies in amounts exceeding the fixed weights. Another reason, essentially an extension, is when the LDC would like to purchase more higher-priced supplies to benefit itself and ratepayers but a loss occurs because of the fixed weights. This problem can arise when the price of a highly reliable supplier drops without a corresponding price drop from less reliable sources.

Suppose an LDC has two suppliers, A and B, with current prices of \$3/Mcf and \$2/Mcf. Also, assume A is the high-reliability supplier and the optimal supplier weights are 1/2 each given current circumstances. The WCOG becomes \$2.50/Mcf under these assumptions. A problem occurs, however, when supplier A drops its price, to, say, \$2.50/Mcf. The new WCOG becomes \$2.25/Mcf for a 25¢/Mcf savings to ratepayers. It can be argued the weights are no longer optimal and should be, for example, 2/3 and 1/3 for suppliers A and B, respectively. The LDC would lose τ (8¢/Mcf) by purchasing supplies optimally. Therein lies the incentive to request a reconciliation.[24]

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[23] Commissions should likewise question large purchase increases from certain suppliers when at the expense of other major suppliers. A more thorough treatment on harmful self dealing is presented in the next chapter on fuel adjustment clauses.

[24] At the optimal weights, ACOG = 2/3(\$2.50/Mcf) + 1/3(\$2/Mcf) = \$2.33/Mcf. The WCOG = 1/2(\$2.50/Mcf) + 1/2(\$2/Mcf) = \$2.25/Mcf. The RCOG = \$2.33/Mcf + τ(\$2.25/Mcf - \$2.33/Mcf) = \$2.33/Mcf - τ(\$ .08/Mcf). Hence, the loss amounts to τ(8¢/Mcf).

The LDC benefits in two ways by requesting a reconciliation and having the weights readjusted. First, it increases reliability at no cost to itself while reducing the risk of potential cost--social, political, and so on--from not satisfying demand. Second, the LDC increases the pressure on supplier B to lower its prices by cutting back on purchases. Under the new weights, supplier B experiences a 40 percent decrease in sales, in revenues, and if cost are constant, in profits. Supplier B could drop its price to regain its position benefitting both the LDC and ratepayers.[25]

In practice, commissions need not readjust weights every time a highly reliable supplier lowers price and others do not follow immediately. Such adjustments should occur only when the effect on consumer welfare is significant, perhaps as measured by CWI, and after some time has elapsed. By waiting, a commission provides time for other market forces to lower the prices of less reliable suppliers, which, if it happened, would pass the entire saving to ratepayers.

Information Sharing

Unlike the LDCs themselves, the commission knows everyone's portfolio of suppliers and the prices paid for gas. This information is quite important but only when appropriately shared. The sharing of price information will benefit most the smaller LDCs whose ability to obtain lower prices is compromised by their size.

Suppliers have an incentive to price discriminate when possible, that is, charge different prices to LDCs based on the elasticities of demand. Since LDCs seldom resell gas to one another the market becomes segmented which must occur for price discrimination to succeed. Commissions can reduce market segmentation, at least partially, by sharing price information with LDCs; in particular, inform small LDCs on the prices paid by larger ones. This may enable small LDCs to bargain more effectively and mitigate discriminatory practices.

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[25] If prices dropped to \$1.50/Mcf and the LDC purchased according to the old weights (1/2 each) the following would hold: WCOG = 2/3(\$2.50/Mcf) + 1/3(\$1.50/Mcf) = \$2.17/Mcf; ACOG = 1/2(\$2.50/Mcf) + 1/2(\$1.50/Mcf) = \$2.00/Mcf; RCOG = \$2.00/Mcf + τ(\$2.16/Mcf - \$2.00/Mcf) = \$2/Mcf + τ(\$ .16/Mcf).

Strengths and Weaknesses of the Fixed-Weight PGA

Incentive-type mechanisms contain potential problems. The FW PGA is no exception, but with proper administration the mechanism should prove beneficial both to LDC shareholders and ratepayers. By constantly monitoring the balance account and frequently assessing LDC purchases for accuracy, commissions maximize the benefits from the FW PGA.

Several advantages already have been mentioned. One is that commissions will be able to determine readily which LDCs are managerially efficient and which are not. Those actively pursuing lower-cost reliable gas supplies will become more profitable and stand out among the rest. Commissions can use the supply portfolios of successful LDCs to set performance standards for those less successful and in doing so better protect retail customers from inefficiency. Another advantage is a more efficient connection between the wellhead and the burnertip markets; retail customers should receive better price signals, which in turn should lead to more efficient consumption and production decisions. The major benefit of the FW PGA is that by allowing LDCs to profit from optimal gas purchases, LDCs are motivated to purchase reliable supplies at minimum cost.

The FW PGA has other merits which show up best when compared to the delayed and partial pass-through PGAs currently in use. Both PGAs are discussed in succession along with examples contrasting them with the FW PGA.

The Delayed Pass-Through PGA

The delayed pass-through PGA is the most widely accepted mechanism to pass along changes in supply costs. The delay refers to the time lapse until retail prices are allowed to adjust to changes in actual supply prices. The argument commonly used in support of delay mechanisms is that such regulatory lags encourage efficient and prudent decisionmaking. When costs are rising, delays force LDCs to economize and choose wisely among supply options to minimize losses. On close examination, however, shortcomings of the delayed pass-through PGAs become evident.

Most state commissions apply true-up procedures to balance an LDC's fuel account: overpayments are credited to retail customers and underpayments are tacked on to retail rates. Consequently, the only real gain or loss to an LDC is the interest revenue gained or lost until the fuel account is balanced. Consider, for example, a 10 percent rise in supply costs that could be reduced to 7 percent if the LDC altered its supply portfolio in a cost-reducing direction. At the market interest rate of 10 percent, the LDC saves only 0.3 percent in lost interest revenue by adjusting its portfolio to the cost-reducing direction.[26] This amount may be inadequate for the LDC to justify the transaction costs of making portfolio adjustments.

An FW PGA provides a better incentive when the LDC receives a sufficient share of any cost savings. Since higher supply prices will quickly raise retail rates, the LDC suffers no losses as long as it purchases the fixed-supply portfolio. Moreover, the LDC can earn a profit by choosing supply options that lower system costs. Any difference between retail revenues and actual costs reflects the amount of cost savings from prudent decisionmaking, a portion of which is kept permanently by the LDC.

An adverse outcome of delayed pass-through is that it invariably causes supply and demand to be out of phase with one another resulting in consumption and production inefficiencies. This consequence becomes clearer when viewing the dynamics of supply and demand forces. When demand increases in response to colder weather, for example, the average supply price for all gas purchases will normally rise as the LDC acquires gas supplies with higher marginal prices. Unless higher supply prices immediately raise retail rates, customers will fail to economize on their gas usage leading to several undesirable consequences.

First, the average cost of gas supplies will be higher than necessary. This follows directly from the failure of consumers to economize, which forces LDCs to

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[26] The loss to the LDC equals the percentage increase in cost times the amount sold (Q) divided by the interest rate. When costs rise by 10 percent and Q is normalized to 1, the loss is (10%/10%)1 = 1%. When costs rise by 7 percent, the loss is (7%/10%)1 = 0.7%. The gain to the LDC from purchasing cheaper supplies is the reduction in lost revenues which is the difference 1% - 0.7% or 0.3%.

purchase greater amounts of gas supplies at higher prices. Second, delays over time can cause inefficient investment decisions, particularly when demand is price elastic because of the direct relationship between capital investment and demand. Overconsumption, especially during peak demand periods, may cause overinvestment in storage facilities, compressors, and other physical facilities. Third, delays that result in overconsumption and higher average costs will decrease an LDC's short-term liquidity by draining its cash reserves needed to purchase gas supplies.

The problems are exacerbated over time when demand returns to expected levels. Rather than seeing lower retail rates, customers see retail rates rise as the higher supply prices for the previous period are passed through. The actual increase is heightened when the PGA includes a true-up provision which compensates the LDC for all fuel expenses. The overly high retail rates cause customers to economize on gas usage when supplies actually are ample. By delaying price changes, both the wellhead and burnertip markets receive information that misdirects decisionmaking and creates unnecessary financial burdens both for LDCs and gas suppliers.

The Partial Pass-Through PGA

Partial pass-through PGAs are harder to assess since their use is more recent, less standardized, and not yet widespread. Usually, they are linked either to some target cost level or to some forecast of future costs. Occasionally they apply solely to specific customers, such as large industrial customers, and sometimes to specific markets such as the spot market. The pass-through of over- or undercharges is typically 90%-10% or 80%-20% with the larger share assumed by retail customers.

The primary difficulty of using partial pass-through PGAs is deciding upon the benchmark for determining rewards and penalties.[27] This difficulty has led to the early dismissal of some partial pass-through PGAs. LDCs have a clear incentive to overestimate future supply costs to minimize the risk and size of losses. The

[27] The FW PGA uses the WCOG as its benchmark, whenever supply prices change WCOG changes implying the benchmark constantly adjusts to current market realities.

commissions, on the other hand, have a tendency to seek stability in supply costs to minimize rate shock. When the forecasts or targets become an integral part of the rate setting process, as they usually are, disagreements are likely to arise and compromises reached.

As with delayed pass-through, the incentive under partial pass-through may be insufficient to induce LDCs to seek cheaper but still reliable supplies of gas. Consider the same example used above in which the cost of gas supplies increases by 10 percent but in which a cost-efficient gas portfolio could reduce the increase to only 7 percent. Under a 90%-10% pass-through rule, the LDC saves only 0.3 percent of the increase by procuring the cheaper supplies.[28] With an 80%-20% pass-through rule, the LDC saves only 0.6 percent. The "savings" are not profits but merely reductions in losses. Whenever gas supply prices rise above those forecasted, an LDC fails to recover fully its expenditures on gas supplies. Behaving efficiently can only reduce the loss, but some losses occur nevertheless.[29]

When supply prices fall an LDC benefits since it shares in the cost savings regardless of whether it behaves efficiently or not. Suppose, for example, supply prices decrease by 7 percent but could decrease by 10 percent if the LDC, say, bargained harder or changed some of its suppliers. The additional profit to the LDC would be 0.3 percent of total cost savings under a 90%-10% pass-through or 0.6 percent if an 80%-20% pass-through were used. Depending upon transaction costs, the additional amount may be insufficient to induce cost-reducing behavior by the LDC. A commission can raise the percentage share to LDCs, which may improve LDC behavior, but to do so would widen the gap between actual costs and retail rates, thereby encouraging inefficient consumption decisions.

The FW PGA, on the other hand, neither rewards nor penalizes LDCs when supply prices fall or rise (other things remaining constant). Rewards can only occur

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[28] The LDC absorbs 1 percent of the increase if costs rise by 10 percent and 0.7 percent if costs rise by 7 percent. The cost-savings to the LDC is the difference, which is 0.3 percent.

[29] Under the FW PGA, an LDC can profit from negotiating a lower price by purchasing amounts exceeding the fixed weight.

when the LDC responds optimally to changed supply prices. The LDC, therefore, must actually change its gas supply portfolio in response to differentials in price increases or decreases among suppliers and markets to improve reliability and earn a profit. If all suppliers increased or decreased their prices by 10 percent, for example, an LDC could not profit by altering its supply portfolio, assuming it was initially minimizing costs. If, on the other hand, some suppliers increased their prices by 12 percent whereas others increased them by only 8 percent, then the LDC and ratepayers both benefit when the LDC shifts its purchases to the less expensive suppliers. The same logic holds when supply prices decrease, that is, LDCs can only profit when they take advantage of price differentials among suppliers.

Some of the current partial pass-through PGAs tie profits and losses to an LDC's participation in a particular market, usually the spot market. For example, the LDC may profit whenever it secures supplies from the spot market at prices below its system average costs. This policy appears sensible since it rewards LDCs and helps lower retail rates; however, the benefits may be more illusory than real. What is crucial is how such purchases modify the expectations of commissions. LDCs may tend to enter longer-term contracts for the bulk of their supplies, do so at a premium price, then engage the spot market solely to make additional profits. As long as long-term suppliers are willing to accept higher prices in exchange for minimum-take flexibility, such a strategy can be both workable and profitable under a partial pass-through PGA. Although retail rates may stay fairly stable since lower spot prices are averaged along with the higher long-term prices, they may be too high nonetheless. To discourage such strategic behavior, a state commission could upgrade spot-market activities into their general expectations of how an LDC should perform. The FW PGA is designed purposely to achieve this outcome.

By using an FW PGA and adjusting the weights, the only way the LDC can profit further is by acquiring more spot supplies, although this may cause problems with its tacit confederate, the long-term supplier. The LDC may try to offer an even higher premium to obtain a lower minimum take but the effect of this on retail rates is limited by the fixed weights. As the LDC transacts more with the spot market, the weight of its long-term supplier shrinks along with its importance to retail rates.

Meanwhile, the LDC fails to profit much from lower spot prices, since it lowers retail rates in line with the fixed weight for spot supplies, a weight which grows at the time of a reconciliation review. In sum, unlike some partial pass-through PGAs, the FW PGA hinders the success of such strategic behavior by realigning the weights with actual purchases and by passing along lower gas supply prices as they occur.

Price Changes, LDC Behavior, and the Design of PGAs

An LDC plays the role of the nexus between upstream suppliers and retail customers. The LDC and supplier are linked by way of the PGA. Therefore, the PGA and its design affects the connection between the upstream supplier and the downstream ratepayer. Originally, PGAs were designed to pass along changes in supply costs quickly; however, it soon became apparent that this design had certain deficiencies, the most unsettling being the relative passivity of LDCs when negotiating for gas supplies. Since the recovery of supply costs was quick and guaranteed, the LDC's investors were relatively unaffected by price changes, which made the LDC less driven to seek lower-cost supplies, especially since almost all LDC sales were made in core markets. Original PGAs became de facto cost-plus contracts. As discussed later, the passivity of LDCs may have contributed to the growing market power of pipelines. This, coupled with some misguided federal regulations, has resulted in problems that today still are not fully resolved.

To encourage more cost-reducing activity, some state commissions have added delayed pass-through, and more recently, partial pass-through provisions. Even though both provisions may spur activity, they are likely to fall short of the objective of inducing LDCs to purchase least-cost gas supplies (discussed earlier). In fact, it is conceivable that higher rates, not lower ones, have resulted. So far, little empirical work has been done on PGAs, but studies on typical fuel adjustment clauses (FACs) used by electric utilities have suggested that those with FACs pay more for fuel supplies than those without.[30] Although the evidence is far from conclusive, it is not inconceivable that this result holds true in the natural gas industry as well. The LDCs have an incentive to pay higher prices for gas supplies in return for greater price stability because neither immediate nor full recovery is guaranteed with a delayed or partial pass-through provision. As stated earlier, delayed pass-through can cause cash flow imbalances and underrecovery for an LDC as easily as partial pass-through PGAs. This problem remains mild as long as supply prices remain relatively stable and predictable through time, which may explain why LDCs have an incentive to "purchase" price stability.

Generally speaking, supply prices change in response to changes in retail demand and to inflationary or deflationary pressures. During inflationary periods, LDCs would suffer losses with either a delayed or partial pass-through PGA, since fuel revenues will either lag or fall below actual fuel costs. During deflationary periods, LDCs would enjoy windfalls in their fuel accounts since fuel revenues will exceed actual costs. Although a rise or fall in demand will likely cause supply prices to rise or fall also, some commissions have already incorporated this into their basic rate design through seasonal rates. For all LDCs, however, the problem most menacing is the occurrence of inflation.

For LDCs under delayed pass-through, the timing of inflationary increases becomes a crucial factor. When inflationary pressures occur during on-peak months, the LDC may experience large cash deficits because of its high volume of system sales. Naturally, the problem of deficits is less severe during off-peak periods when LDC purchases decrease. The LDC, therefore, may offer a premium to suppliers who willingly agree to make inflation adjustments during the off-peak periods. Then again, suppliers may try to profit from the LDC's vulnerable position and further raise this premium. As the LDC tries to shore up its vulnerable position, it penalizes the ratepayer by agreeing to higher supply prices. The ultimate outcome is that

[30] D. L. Kaserman and R. C. Topel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economic Journal* 48 (1982): 687-700.

expectations of lower retail rates from incorporating delays may prove more elusive than attainable.

For LDCs under partial pass-through, the size of the inflationary increase also has important implications. High levels of unexpected inflation result in supply costs well above those forecasted. Although much of the increase is passed on to ratepayers, a percentage remains to be absorbed by the LDC and its investors. The LDC will absorb greater losses during its peak demand periods than otherwise because of its need for larger supplies. Unlike delayed pass-through, however, the LDC need not bargain directly with suppliers to reduce the severity of its financial losses; instead, it can try to bias its forecast of supply costs in ways that will transfer the risk of inflationary prices to ratepayers.

Since losses rise directly with demand for a given level of inflation, the LDC will try to overestimate its peak-demand supply costs more so than off-peak. As shown in Figure 4-2, this will tend to steepen the forecast line. The upper and lower solid lines separate the area in which supply costs are likely to fall when inflationary and deflationary pressures both are considered. The dashed line that bisects the area represents an unbiased forecast that equally shares the risks from inflation and deflation with ratepayers. The steeper dashed line depicts a biased forecast. The biased forecast lies above the unbiased one to indicate the shifting of risk away from the LDC and toward ratepayers. The steeper incline illustrates that the amount of risk reassigned to ratepayers rises with demand. Because LDCs have an obligation to serve, they become more vulnerable both to inflation and opportunism by suppliers as demand increases. To protect itself, an LDC may not negotiate hard with its suppliers and instead overestimate future supply costs, particularly those at peak demand. An overly high forecast leads to excessive retail rates since forecasts are used to set rates. The primary benefits to the LDC from overforecasting costs are (1) it lowers the probability of absorbing a loss, (2) it reduces any losses that do occur, and (3) it raises the probability of earning a profit.

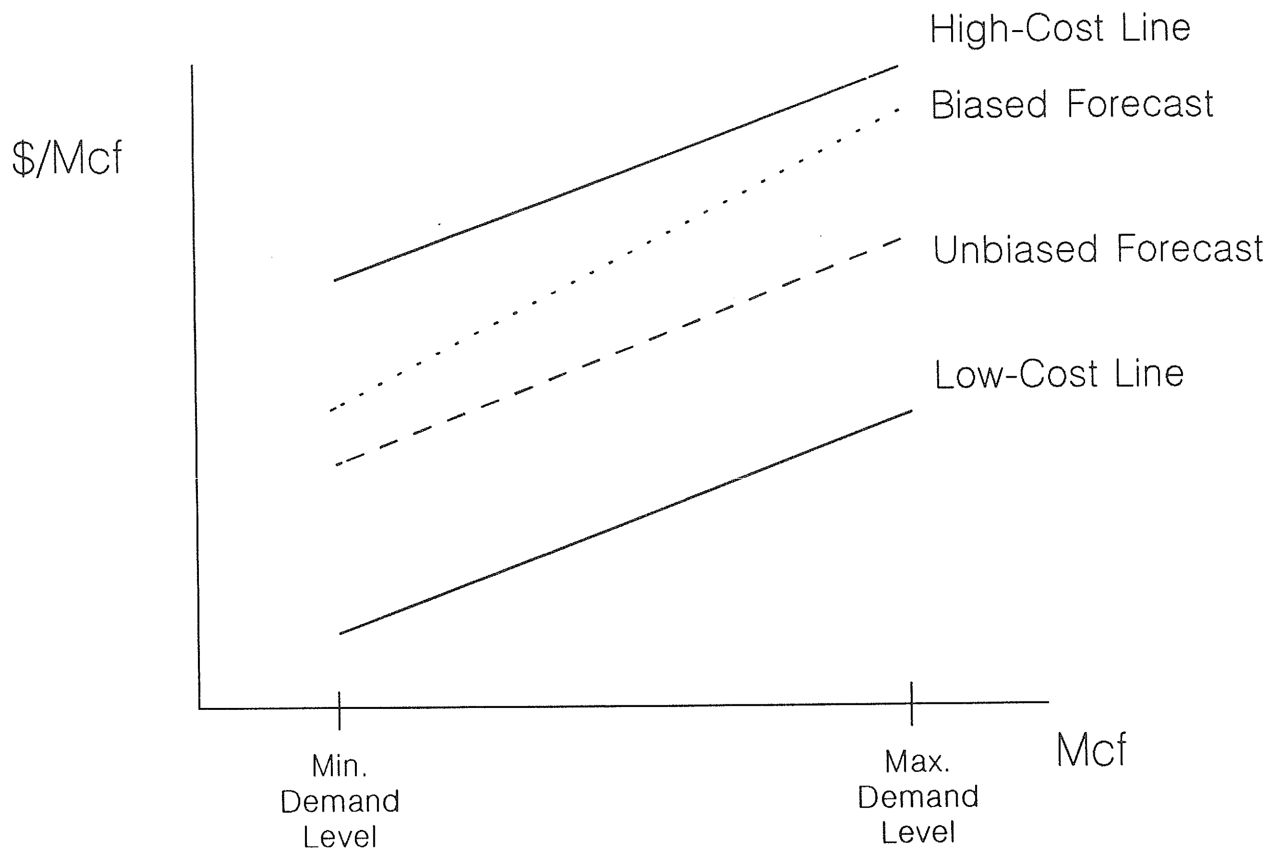

Fig. 4-2. The effect of a partial pass-through provision on LDC forecasts.

As LDCs try to strengthen their financial position against inflation and opportunistic suppliers, they worsen the position of ratepayers by overforecasting supply costs. This strategy, however, may prove unsuccessful especially when large upstream suppliers have access to the forecasts used to establish future retail rates. Armed with such knowledge, a large supplier could set its prices equal to or close to those forecasted without inciting much reaction from the LDC. Disclosing forecasts is similar to the notion of "posted prices" in economics. As is well known through experimentation, when buyers post bids these become price floors with final prices usually higher as a consequence.

The FW PGA puts both the LDC and the ratepayer in less vulnerable positions. Retail rates adjust automatically to inflationary and deflationary pressures and to shifts in demand. Forecasts will not be biased since forecasts are irrelevant. The LDC has no need to purchase price stability since price instability does not necessarily impose any losses. In fact, instability opens the door of opportunity, since LDCs would have more flexibility to change their gas supply portfolio. This has the desirable effect of lowering gas supply costs, benefitting both the LDC and ratepayers. This latter point cannot be overemphasized. The FW PGA can actually encourage competition among suppliers and markets whereas delayed and partial pass-throughs encourage the opposite. Price changes, in and of themselves, do not profit the LDC unless they are accompanied by portfolio changes. The LDC, therefore, has a profit incentive to react to price differences among suppliers or markets in ways that lower costs or raise reliability. Such behavior will reward lower-priced reliable suppliers with higher sales and, at the same time, punish high-priced suppliers with lower sales.

PGAs and the Design of Contracts

Many of the consequences of various PGAs can be seen through contractual arrangements. For example, most longer-term supply contracts have escalator clauses that tie their price to the price of other fuels, to spot market prices, or to the prices of other suppliers. The price in most forward contracts is the futures price plus some percentage add on. Both delayed and partial pass-through PGAs have encouraged the linking of markets and suppliers to one another and, rather than stimulating competition, actually have hindered it.

Linking supply prices is an attempt by LDCs to acquire price stability and discourage opportunistic behavior from suppliers. Unfortunately, these goals are fleeting when one considers the ramifications of the strategy. In some cases, the "price-linking" strategy amounts to a "meeting the competition clause" (MCC), which forces a supplier to lower its price whenever the buyer finds a lower price for the good or service in question. The major drawback to MCCs is that they discourage competition since a competitor realizes that lowering its price only induces others to do the same. Price competition becomes irrational; therefore competitors avoid using price as a means to attract customers and as a result, prices take on a ratchet feature, namely, easy to rise but hard to fall.

It may be argued that linking market prices is not the same thing as linking supplier prices. In general this may be true, however, in the natural gas industry, those who supply gas to the long-term market often supply gas to the spot, forward, and futures markets. By linking markets through contractual stipulations, LDCs offer suppliers a rigid structure from which to raise prices. By agreeing to limit competition or to raise prices in one market, suppliers can control or raise prices in all remaining markets.

A common variant of the MCC is the "meet or release" (MOR) or "market out" clause. The MOR clause can be found in many spot market contracts and enables the current supplier to meet a competitor's price or release the buyer from its contractual commitments. Although this seemingly benefits the buyer, its actual effect is to inform one supplier about the price offers of others. Disclosing price information actually fosters collusive behavior among suppliers since it becomes more difficult to bargain secretly with one another's customers. Again, higher prices will result but LDCs are unlikely to complain since greater price parity and stability result also.

Both delayed and partial pass-through have likewise fostered "most favored nation" (MFN) clauses found in many gas contracts. The purpose of an MFN is to protect the buyer by insuring that other buyers do not receive lower prices. An MFN forces the supplier to reduce its price to everyone when it does so for anyone, and thereby inhibits the supplier from selectively lowering prices and price discriminating among LDCs. The LDCs benefit because MFNs, especially when coupled to MCCs, help stabilize supply prices and soften the impact of delayed and partial pass-through PGAs. Unfortunately, MFNs cause higher supply prices to the detriment of ratepayers, and essentially amount to a standardized price premium.

In sum, delayed and partial pass-through PGAs encourage LDC passivity and the acceptance of higher prices in return for greater price stability and parity. The MFN, MCC, and MOR clauses allow suppliers to charge price premiums in ways that encourage and enforce collusion. Examples of LDC passivity are clearly evident when reading provisions found in some gas contracts. The following adaptation is from an actual spot market contract which contains an MFN price protection clause.

> In the event [Buyer] or any other gas purchaser shall pay for any gas delivered. . .under conditions comparable to those provided herein, a price higher than that provided here, to any seller, then the price of all gas delivered hereunder shall be increased to an equivalent price. [Buyer] shall have the right to require under the provision of this paragraph reasonable proof of the delivery of gas to any other gas purchaser and the price thereof.

The FW PGA should discourage the relative passivity of LDCs as reflected in many gas contracts. By not penalizing LDCs for price instability and by rewarding them for gas portfolio changes, an LDC can become more active and aggressive in securing its gas supplies. In a way, the FW PGA merely extends the basic design of original PGAs. It passes along price changes (as did the original PGAs) but adds a profit incentive to encourage LDCs to seek lower-cost supplies. Contractual terms will likely change also as LDCs become more aggressive negotiators. Clauses such as the MFN should appear less frequently as suppliers are forced to compete for buyers. As a result an LDC will pay a price more aligned with its own characteristics rather than one based on others who value the service most. The MCC and MOR clauses will likely continue; their use, however, will encourage competition rather than enable collusion. It should be kept in mind that both the MCC and MOR clauses are useful in dispersing price and nonprice information, and when doing so, enhance competition by lowering transaction costs.

Financial Markets, Competition, and PGA Design

Delayed and partial pass-through PGAs both encourage LDCs to follow strategies that result in more stable and predictable prices. A primary goal of LDCs is to balance fuel accounts and enable capacity payments to fully cover the cost of capital and earn investors their fair rate of return. As LDCs try to link markets and suppliers through contracts, they have raised the level of parity among themselves as a byproduct. But as argued above, the cost of parity, stability, and predictability can be high retail rates and passive LDCs. Another cost is that investors do not receive the types of signals necessary to distinguish efficient from inefficient LDCs.[31] Consequently, investors will select LDCs primarily on current rates of return rather than expected future returns since information on efficiency is inadequate.

The FW PGA should reduce investor passivity. As LDCs search for lower-cost supplies and earn profits, any difference in managerial abilities will manifest, allowing investors to distinguish more easily the efficient LDCs from the inefficient ones. As investors respond, the stock value of efficient firms will rise and debt financing will become more affordable. The less efficient LDCs, by contrast, will experience lower stock values and less affordable credit.

The response of investors may become an important catalyst to LDCs. Although the FW PGA allows LDCs to profit, there is no guarantee that LDCs will respond. Active investors, however, will penalize inactive LDCs and reward active ones; although LDCs do not compete directly, they do compete against one another and against other firms in the financial markets. Given the competitiveness within financial markets, once some LDCs begin to experiment and profit the others will likely follow because of pressures from investors.

In addition to the financial markets, the LDCs face another competitive dilemma imposed by large price elastic customers: either lower rates or risk load loss. The LDCs have responded up to now, and rather successfully, by offering interruptible

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[31] Under the FW PGA, LDCs earn additional profits from optimally interacting in gas supply markets. Investors could use this along with other information to better assess LDC efficiency.

rates, block rates, economic incentive rates, and so on to maintain large customers in ways palatable to state commissions. A rather recent but emerging approach is contract pricing wherein an LDC and a large customer enter into a customized agreement. LDCs, however, may have little bargaining power and become easy prey to opportunistic customers. In several ways delayed and partial pass-through PGAs have weakened the LDC's bargaining position, and as a consequence, have compromised the position of small retail customers.

Delayed and partial pass-through have made capacity revenues the primary source of an LDC's profits. The LDC has little choice but to maintain system sales if it intends to pay creditors and enable investors to earn a fair rate of return. Large customers, recognizing the LDC's tenuous position, will try to threaten LDCs into lowering their retail rates. An FW PGA offers an LDC some recourse to a secondary source of profits that depends upon cost efficiency. By dealing with suppliers intelligently, LDCs can earn profits by lowering costs. As an additional benefit, lower costs make for lower rates, which lessens the likelihood that large retail customers will desire to bypass the system anyway.

Concluding Remarks

The defining feature of the FW PGA is its tying profitability to optimal behavior. By efficiently securing gas supplies and outperforming the fixed-weight portfolio, an LDC can earn profits that ultimately benefit both shareholders and ratepayers. Unlike the delayed or partial pass-through PGAs, a closer and less distorted linkage between the wellhead and burnertip markets emerges with greater consumption and production efficiencies the likely outcomes. As LDCs become more aggressive in dealing with upstream suppliers, they become more adept at servicing the needs of ratepayers.

For efficient LDCs, current problems such as the threat of bypass would become less severe since the cost savings to large retail customers from bypassing the LDC would diminish. The current remedies to thwart bypass create price disparities among customer classes that have resulted in distortions in both the supply and demand markets. The FW PGA encourages LDCs to behave efficiently and secure gas supplies at minimum cost. Rather than distort retail rates, and in particular raise the rates of small captive customers, the cost savings can be disbursed in ways that satisfy large retail customers while allowing the LDC to remain competitive. The importance of retaining large retail customers will become apparent also as LDCs may be asked by their regulators to use their share of the cost savings to thwart bypass. The LDCs may begin to realize other services exist that they can offer large retail customers and still earn a profit.

Fixed-weight PGAs also could affect in a favorable way a recent trend in state regulation. The present direction might be characterized as moving toward "regulation from within," as commissions become increasingly involved in the daily activities of LDCs. A growing amount of commission resources are being expended on preapproving, monitoring, and auditing LDC decisions to determine their prudence and accuracy. In some ways the FW PGA should help lighten regulatory burdens by offering commissions a suitable benchmark to compare LDCs and to guide commission efforts better. Rather than attempting to construct a suitable benchmark, commissions can evaluate an LDC's performance by comparing its actual gas supply portfolio to the fixed supply portfolio. The cost savings of the more efficient LDCs can become the benchmark from which to judge others, as well as to reset retail rates for the less efficient LDCs. Any losses imposed on inefficient LDCs would accrue to their investors, who should then perform their primary duty of disciplining management and making changes when necessary.

The growth and maturation of LDCs will not take place immediately: they have no choice but to learn by trial and error. Many LDCs are currently involved in overly expensive contracts, which in many ways resulted from some misguided regulation (mostly at the federal level). Current contractual constraints must loosen before the LDCs can grow and learn to become more efficient buyers and suppliers of natural gas. In some cases the best way to relieve LDCs from these constraints will be to allow them to buy down or buy out old obsolete contracts. In other more extreme cases, the best policy may be to allow bankruptcy to free LDCs to bargain with new suppliers. Regardless of the approach taken, LDCs will require some time to discard their old tried-and-true ways of doing business and adopt more aggressive techniques.

CHAPTER 5

FUEL ADJUSTMENT CLAUSES IN A MORE OPEN MARKET ENVIRONMENT

In many respects the problems posed by current fuel adjustment clause practices are similar to those posed by current purchased gas adjustment clauses. Simply stated, because of a more active wholesale power market that now includes competitive bidding and new entrants such as qualifying facilities (QFs) and independent power producers (IPPs), electric utilities have a greater diversity of supply sources from which to choose. The Clean Air Act Amendments of 1990 also might make fuel prices more volatile. Given the greater number of power and fuel supply sources now available to electric utilities, there is a need to reexamine whether current fuel adjustment clauses convey the proper incentive to an electric utility to minimize its costs, and if not, whether a need exists to examine how FACs might be redesigned to provide incentive compatibility; that is, where an electric utility is rewarded for searching out lower cost fuel, while ratepayers also benefit.

The Incentives Conveyed by the Current Delayed and Partial Pass-Through FACs

Delayed and partial pass-through FACs have the same limitations as their PGA counterparts and more. One source of additional problems stems from the fact that resources must be transformed into electricity through a generation process. In addition to consumption inefficiency, delayed and partial pass-throughs also can result in production inefficiency. Another source involves interutility power transactions. LDCs seldom involve one another in transactions, but in the electric industry utility-to-utility transactions are commonplace. As a result, any price or production distortions caused by delayed and partial pass-throughs will affect wholesale power markets.

A third source of problems stems from the formation of subsidiaries and the potential for self-dealing abuses. The electric industry contains many vertical relationships such as utilities owning upstream input suppliers, for example, coal companies, and power producers such as IPPs, QFs, and cogenerators. There are horizontal relationships also such as, for instance, utility joint ventures and affiliated IPPs that sell power to retail customers. Any impact delayed and partial pass-through FACs have on utility decisionmaking will affect the relationship with affiliates and the cost of *producing electricity.*

Delayed Pass-Through FACs

Consumption and Market Inefficiencies

As discussed in the previous chapter, delayed pass-through PGAs can cause supply and demand forces to become out of phase resulting in consumption and supplier inefficiencies. Delayed pass-through FACs also promote inefficient signaling between supply and demand markets. As supply prices rise, there is no corresponding rise in electric rates resulting in overconsumption by an amount dependent upon the price elasticity of demand.[1] Because electric rates fail to rise with cost, consumers fail to economize on electric usage sending input suppliers the wrong message on the value of their input. Suppliers will believe that their input is more valuable than it actually is, and as a result, may make inefficient production and investment decisions.

Of course, the same argument holds for price decreases. As input prices fall, the delay in pass-through keeps electric rates inefficiently high resulting in underconsumption. From a supplier's viewpoint, lower prices do not translate into higher demand levels. This can result in a variety of reactions by suppliers, none of which is likely to be efficient. Some suppliers may scale down expectations of future profits, and as a consequence, scale down current investment activities. Other suppliers may conclude that demand is more price inelastic than it actually is and decide to quickly raise prices to levels higher than they were originally.

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[1] The more elastic the demand the greater the overconsumption.

Production and Investment Inefficiencies

Delayed pass-through FACs can also distort production and investment decisions by utilities. Utilities will have an incentive to shy away from inputs whose prices vary a lot since delays tend to make these inputs appear relatively more expensive. When the price of an input increases, utilities immediately must pay more although consumers do not. During the delay, the utility must finance all additional expenses either by borrowing funds at short-term interest rates or by foregoing interest revenue from funds that could have been invested. From the utility's viewpoint, the actual increase in price exceeds the increase quoted by the supplier. This may cause the utility to underuse the input and overuse others at the margin. Of course, the overall reduction in the input's usage will be inefficiently low because the delay in raising electric rates creates overconsumption. Since the utility has an obligation to serve, it has no choice but to purchase needed supplies.

When the price of an input decreases, the utility will use more than the efficient amount when pass-through is delayed. The amount of overuse is larger when the utility gets to keep any interest revenue from cost savings temporarily held. The overuse of one input implies an underuse of others and results in an input mix which is not minimum cost. Of course, the wrong input combination implies production inefficiency and higher production costs.

A utility may attempt to minimize the effects of volatile input prices in various ways. One approach would be to invest mostly in generation technologies that use inputs whose prices vary least regardless of whether such investments minimize the costs of generating electricity. That is, delayed pass-through may encourage malinvestment. Normally, price volatility is indicative of a competitive market process whereas stagnant prices or prices that move in a trend-like fashion are generally indicative of market structures with monopolistic or oligopolistic traits. Competitive markets pass cost information to consumers more efficiently than do less competitive market structures. When costs vary, competitive input markets will show greater price variability given demand than would monopolistic or oligopolistic markets. Delayed pass-through, therefore, has a tendency to drive utilities away from competitively priced input markets and towards those which are not.

Another approach available to utilities is to enter inefficient contractual arrangements, as discussed in the previous chapter on PGAs. Since price volatility can be costly to a utility operating under a delayed pass-through provision, the utility could offer to suppliers a price premium in return for price stability. Naturally, this can lead to higher electric rates for consumers. The utility may be willing to accept this tradeoff, however, since it helps maintain an adequate return to investors.

One dimension present in the electric industry that is absent in the natural gas industry is the prevalence of vertical relationships. Utility ownership of upstream suppliers enables them to acquire price stability in a less costly and risky manner once the investment is made. Ownership protects against opportunistic behavior that can occur in contractual relationships and offers greater control over the timing of price changes. Although it may be less costly for the utility, it does not necessarily follow that this approach is less costly to ratepayers. By owning or partially owning an input supplier, the utility is better able to enforce any contractual arrangements which thereby reduces its risk; however, there is no incentive for it not to pay its affiliate a price premium since it shares in the profit from so doing. In fact, the utility's incentive would be to pay the maximum premium possible given regulatory oversight because it is neither the investors nor the utility that eventually pays for the premium, but rather, the ratepayers. Although FACs may not cause self-dealing abuses, their design can exacerbate the consequences.

In short, delayed pass-through FACs can promote inefficiency in industrial organization by encouraging utilities to prefer vertical relationships to long-term market transactions and to prefer long-term stable relationships to more volatile short-term ones.

Incentive Inefficiency

Delayed pass-through FACs also provide inefficient incentives to control costs for reasons discussed in the previous chapter examining PGAs. Suppose, for example, inflationary input prices cause operating costs to rise \$1,000,000 a month, an amount that could be kept to only \$700,000, say, if the utility changed input suppliers. The monthly benefit to ratepayers would be \$300,000. Whether the utility will purchase the lower-priced supplies, however, depends upon its benefit, which, in turn, depends upon market interest rates and the timing of true-up procedures.

A true-up procedure ultimately ensures the utility full recovery of all prudent expenses not covered by ratepayers during the delay period. Suppose the delay is three months, the interest rate is 12 percent a year and true-up procedures occur every six months. Because the delay is three months, the utility will experience a cash deficit of \$3,000,000 until the rate increase takes effect or \$2,100,000 if the utility responds efficiently. Because the true-up procedure does not occur for six months, the loss to the utility under each scenario becomes:

$$\text{Loss if inefficient} = .06(\$1{,}000{,}000) + .05(\$1{,}000{,}000) + .04(\$1{,}000{,}000) = \$150{,}000;$$

$$\text{Loss if efficient} = .06(\$700{,}000) + .05(\$700{,}000) + .04(\$700{,}000) = \$105{,}000,$$

where the decimals denote the annual interest rate adjusted for the time lapse until the true-up review.[2] The benefit to ratepayers depends upon the length of time the cost savings last as well as the interest rate. Assuming the cost savings is constant at \$300,000 a month until true-up, the total benefit to ratepayers equals \$1,863,000. So by behaving efficiently the utility will save ratepayers \$1,863,000 and yet will lose \$105,000 unless the true-up procedure reimburses it for lost interest revenue. Of

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[2] The formula for calculating the interest revenue loss or gain when using monthly interest rates and when the amounts gained or lost varies month to month is:

$$\sum_{i=1}^{t} A_i(1 + r_i)^{t-i} ,$$

where r is the monthly interest rate, A_i is the amount in month i gained or lost, and t denotes the number of months until the next true-up review.

course, the utility loses less by behaving efficiently--$45,000 to be exact--however, this incentive is rather small when compared to the $1,863,000 savings to ratepayers.

The additional loss to the utility from not behaving efficiently amounts to only 0.75 percent of the increase in operating costs. As in the case of PGAs, delayed pass-through FACs contain an inefficient incentive mechanism partly because the reward offered is meager unless interest rates are astronomically high. Another cause of inefficiency is that utilities always lose when fuel costs rise and gain when they fall regardless of whether they had anything to do with the price change, which further encourages utilities to own upstream suppliers. In the above example, it would cost a utility only $150,000 to increase a subsidiary's revenue by $6,000,000.

Another option to dissipate losses is through short-term wholesale power markets. The FERC allows utilities to pass through the purchase price of a short-term transaction as long as it is below total variable cost. During inflationary periods, both the buyer's and seller's cost will increase; however, the seller could attach an adder to its cost to help cover losses caused by the delay in raising retail rates. Of course, only utilities that are net sellers ultimately benefit, financed by the retail customers of utilities that are net buyers.

Partial Pass-Through FACs

As with PGAs, partial pass-through FACs usually contain a deadband zone wherein cost changes are forwarded to ratepayers dollar for dollar. When costs exceed the ceiling or fall below the floor then the sharing rule becomes effective, with the utility commonly assuming 10 to 20 percent of cost over- or underruns. Partial pass-through FACs have been used infrequently by state commissions; they also tend to vary significantly in design, although most designs incorporate a forecast of future costs.[3] Profits and losses to the utility usually are determined by how well it performs relative to the forecast.

[3] Only a handful of state commissions have considered or implemented a partial pass-through provision. Currently, only three commissions have one in use. For more detail, Chapter 3 presents the NRRI survey results on FAC practices.

Incentive Inefficiencies

Ideally, commissions and ratepayers want utilities to be as fuel efficient as possible since this translates into the lowest possible energy rates. When actual operating costs are within the deadband zone, however, the utility has little incentive to seek maximum efficiency: on the one hand, the utility earns no additional profit from lowering the average fuel costs (cents per kilowatthour), on the other, all cost increases within the zone are passed through quickly to ratepayers. Consequently, the deadband zone can be regarded as incentive-neutral rather than incentive-compatible, thereby leading to the possibility of lackadaisical performance by utility management. Only when the average fuel cost approaches either boundary does utility behavior become more responsive.

How the utility will respond at the boundary depends more on how it arrived there than which boundary it confronts. If, for example, inflationary fuel prices cause operating cost to exceed the upper boundary, there is an incentive for the utility to overuse the more fuel efficient generation facilities to reduce fuel usage per kilowatthour. The incentive toward overuse stems from partial pass-through; each unit of fuel consumed creates a loss to investors. By reducing fuel usage, average fuel cost decreases reducing any loss the utility's investors might have to absorb. The utility could, for example, cut back on spinning reserves, delay maintenance, or increase line loadings in an attempt to minimize fuel consumption. That is, a utility may willingly accept lower reliability in exchange for lower investor losses.

On the other hand, operating cost may rise when the price of a particular fuel increases but general inflation is not occurring. In this case, the utility has the proper incentive to minimize fuel costs by substituting for the higher-priced input. Again, if average fuel cost remains above the upper boundary there is a further incentive to reduce usage in ways that may not be desirable.

The same reasoning holds during deflationary episodes or when particular fuel prices drop relative to others. In the first instance, the utility may try to maximize its profit by lowering fuel usage to minimize average fuel costs. The methods used to lower fuel usage, as stated above, may, however, compromise reliability or other operational aspects of electricity generation and in doing so generate hidden costs.

Inflation is worrisome to a utility since it can result in losses to its investors. One way utilities can control inflationary prices is by owning upstream suppliers, but partial pass-through offers them an additional way through cost forecasting.

Forecast Bias and Ownership Inefficiency

As stated above, forecasts of future costs are generally an integral part of a partial pass-through FAC. In some cases, the forecast becomes the upper boundary implying that as long as the actual costs are below the forecasted amount the utility can pass through all fuel costs. Of course, as argued in the previous chapter on PGAs, this creates an incentive for the utilities to overforecast future costs and thereby minimize the risk of absorbing losses. The amount of bias will likely be greater for estimates of peak fuel costs than offpeak because system sales are higher during peak periods, making total losses higher for any given percentage of underprediction.

When choosing whose forecast to use--for example, either the commission staff's or the utility's--the commission is likely to consider the accuracy of previous forecasts. This places the commission at a relative disadvantage, particularly when the utility's subsidiaries supply either raw materials or wholesale power. The consequence could be a "one-hand-washes-the-other" policy wherein the subsidiaries set prices to enable an accurate utility forecast and the utility bases its forecast on input prices favorable to the utility. As a consequence, subsidiaries remain profitable, the utility appears competent, and investors assume less risk. The typical justification for supplier ownership is reliability and cost efficiency, but partial pass-through FACs add another justification, at least from the utility's viewpoint: regulatory protection.

The Fixed-Weight FAC

The philosophy of the fixed-weight (FW) FAC is the same as its PGA counterpart; namely, reward utilities for outperforming the fixed weights. There are two types of fixed weights comprising the FAC: supplier weights and input weights. Supplier weights are analogous to those used in the FW PGA. In the FAC, however, input weights are used in place of the PGA's market weights. An input weight represents the importance of a particular resource in the various stages of generation. For example, a commission may define different input weights for peak and offpeak generation since the resource mix consistent with minimum operating cost is likely to differ. Table 5-1 depicts a potential set of input weights for a utility that uses coal, natural gas, and purchased power to meet peak and offpeak load requirements. The utility has a choice over the quality of coal--high Btu and low Btu--whereas natural gas is assumed homogeneous in quality. For offpeak generation, high Btu coal accounts for 60 percent of the total Btu requirement whereas low Btu coal and purchased power account for 30 percent and 10 percent, respectively. During peak generation, the importance of each input changes as evidenced by the input weights with natural gas and purchased power becoming relatively more important energy inputs.

TABLE 5-1

INPUT WEIGHTS FOR PEAK AND OFFPEAK GENERATION

Period	Coal		Purchased	Gas
	High Btu	Low Btu	Power	Standard Btu
Offpeak[1]	.6	.3	.10	0
Peak	.4	.2	.2	.2

[1]Each weight measures the fraction of total Btus supplied by the fuel input.

The optimal value of input weights can be determined by production and load simulations using standard computer software. A utility once given information on load patterns, fuel prices, facility availability and reliability, and any other pertinent information, can find the weights which minimize expected peak and offpeak generation costs. An input weight equals that input's contribution toward total Btu requirements needed for a standard unit of output (MWh). Input weights bridge Btu (input) to MWh (output) and therefore are connected to system heat rates.

Once the set of optimal input weights has been determined, the utility is free to purchase any combination of inputs it desires. The role of the "fixed" input weights is to work along with the "fixed" supplier weights to determine the target operating cost (TOC). For example, if prices of high Btu coal from all suppliers increased by 10 percent, then offpeak TOC would rise by 6 percent and peak by 4 percent using the input weights in Table 5-1. Actual operating cost (AOC), however, depends upon the utility's actual purchase decisions and on how it combines inputs to generate electricity. In this example, the utility could use less high-Btu coal and more of the other inputs so that AOC is below TOC. As discussed more fully later, the FW FAC rewards utilities when AOC is below TOC.

Operating Cost and Efficiency

Operating cost ($/MWh) is given as the product of fuel cost ($/MBtu) and the heat rate (MBtu/MWh) plus expenditures on purchased power ($/MWh). So if fuel costs are $2.00/MBtu and the heat rate is 10 MBtu/MWh then operating cost equals $20/MWh. If 80 percent of total load requirement is self generated with 20 percent purchased at, say, a price of $25/MWh, then system operating cost would be $21/MWh.[4]

The utility earns a profit in the FW FAC whenever AOC is below TOC. A relevant question is whether attempts to lower AOC would lead to inefficient purchase and generation decisions by utilities. The answer is "no." The reason can

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[4] OC = .8($20/MWh) + .2($25/MWh) = $21/MWh.

be seen when viewing the role of TOC. Once supplier and input weights both are determined, the utility has no control over the value of TOC because all value changes are determined by changes in input prices.[5] Although the fixed weights are optimal initially, they fail to remain so as input prices change, which implies that the value of TOC is above the minimum possible operating costs (MOC). The utility by adjusting purchase and input decisions can lower AOC below TOC, and in doing so earn a profit tied to the value of (TOC - AOC). Important for efficiency considerations, the maximum difference between TOC and AOC occurs when AOC=MOC. Hence, the utility can only maximize its reward if it can determine the least-cost combination of inputs and if it reduces purchases from relatively expensive suppliers.

The Use of Fixed Weights to Determine TOC: An Example

The fixed input weights are designed to encourage a utility to minimize operating cost once input costs are known. The supplier weights are designed to encourage the utility to minimize input costs once input prices are known. When a supplier raises its input price, the increase to TOC depends upon the supplier's weight and the importance of the input to generation; that is, it depends upon the input weight. For AOC to approach MOC, a utility must alter the amounts purchased from suppliers as prices change as well as determine a more optimal, lower-cost input mix. An example of this is shown by using the information provided in Table 5-2.

The utility has two suppliers of high Btu coal, A and B, and two suppliers of low Btu coal, C and D. As the input weights indicate, high and low Btu coal each account for one-half of total Btu requirements with heat rates of 10 MBtu/MWh and 11 MBtu/MWh respectively. The general formula for TOC is $\sum_{i=1}^{n} \sum_{j=1}^{m} \alpha_i \beta_{ij} P_{ij}$,

[5] This assumes the utility is a "price taker" in input markets. In a later section on self-dealing, the utility as a "price maker" is examined.

TABLE 5-2

INITIAL SUPPLIER AND INPUT INFORMATION
FOR A COAL GENERATING UTILITY

	High Btu		Low Btu	
Suppliers	A	B	C	D
Weights	.5	.5	.5	.5
Price ($/MBtu)	2.00	2.00	1.80	1.80
Input Weights	.5		.5	
Heat Rate	10 MBtu/MWh		11 MBtu/MWh	

where α_i is the product of an input weight and the heat rate; β_{ij} are supplier weights and P_{ij} are supplier prices. In our example, TOC becomes $19.90/MWh.[6]

For convenience, assume that the supplier and input weights are optimal initially so that TOC=MOC. Suppose, however, that supplier A raises its input price to $2.40/MBtu. This causes TOC to increase to a value of $20.90/MWh, which is calculated by replacing supplier A's old price with the new one in the TOC equation. The utility, though, can reduce AOC by: (1) increasing purchases from supplier B relative to A, (2) increasing the usage of low Btu coal, or both.

Because of contractual restrictions such as minimum takes, assume the utility can only increase purchases from supplier B to the point where its actual weight becomes 0.7, making supplier A's actual weight 0.3. That is, rather than purchase

[6] TOC=(5 MBtu/MWh)[.5($2.00/MBtu)+.5($2.00/MBtu)]+(5.5 MBtu/MWh)[.5($1.80/MBtu)+.5($1.80/MBtu)]=$19.90/MWh, where the terms within the brackets are supplier weights (β_{ij}) and prices (P_{ij}) and the terms outside are the products of the input weights and heat rates (α_i).

half of its high Btu coal from A and half from B as indicated by the fixed supplier weights, the utility could purchase 30 percent from supplier A and 70 percent from B, making actual supplier weights 0.3 and 0.7 respectively. Based on this change alone, the AOC drops to \$20.50/MWh for a savings of \$.40/MWh. The average price of high Btu coal drops from \$2.20/MBtu to \$2.12/MW because of the changed supplier weights. Even with this drop in average price, however, it is more expensive relative to low Btu coal then before the price increase. By responding to the relative change in average input prices, the utility would reduce AOC further if it used more low Btu coal and less high Btu coal to generate electricity; that is, if it increased input weight of low Btu coal and lowered the weight of high Btu coal. By doing so, AOC moves closer to MOC, which the utility desires since this maximizes its reward. Suppose for technical reasons such as reliability and stability constraints that the best set of input weights attainable for high and low Btu coal is (0.4, 0.6). The new input weights along with the new supplier weights result in an AOC of \$20.36/MWh for an additional savings of \$.14/MWh making total savings \$.54/MWh.

By efficiently changing supplier and input weights, the utility is able to partially offset the effects of a higher input price on operating costs and in a manner that benefits itself and ratepayers. The manner in which ratepayers benefit is discussed more fully in the section on energy rates. In principle, however, ratepayers benefit because energy rates are based mostly upon the value of AOC and to a lesser degree upon TOC.

The Role of Purchased Power

Besides self generation, a utility can use purchased power to fulfill its power needs. Purchased power includes long-term requirement transactions wherein committed capacity and minimum energy takes are contracted for, and short-term coordination transactions such as economy power. The energy component of long-term purchased power should be treated as any other fuel input in that both supplier and input weights should be assigned. For short-term purchased power, however, no weights are assigned making them not directly a part of the FW FAC. In part, this is for practical reasons since short-term transactions, particularly economy power, do not involve any lasting commitment by the buyer and seller, nor do they constitute a reliable source of power.[7] What they do offer is the possibility of lowering operating costs by displacing either self-generation or long-term purchased power. As a consequence, they should be encouraged.

Although there are no assigned weights, the FW FAC encourages utilities to engage short-term power purchases whenever they lower AOC. This follows because TOC is fixed by fixed weights and current input prices, whereas AOC is controllable and depends directly upon utility input decisions. The profit to the utility varies directly with the difference between TOC and AOC, so whenever the utility can lower AOC through short-term power purchases it would have an incentive to do so. Since the incentive exists without inclusion in the FW FAC, no reason exists to include short-term purchased power especially in view of the accounting problems surrounding capacity payments.

One nagging problem concerns the treatment of capacity charges that may accompany short-term power transactions. The policy that best ensures efficient decisionmaking is to avoid separating the price of short-term power into capacity and energy charges. The only important issue is whether the purchase price is above or below the marginal operating cost at the time of purchase. If the price is below marginal cost then the utility should engage the short-term transaction and either displace self generation or temporarily reduce long-term purchased power. Similarly, if price is above marginal cost then the utility should avoid the transaction and has the incentive to do so.

The Energy Rate Formula

The energy rate ($/MWh) is the per unit price paid by ratepayers to cover the utility's operating costs. Although expressed in dollars-per-megawatthour units to maintain continuity of exposition, it is easily convertible to cents per kilowatthour,

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[7] In principle, the FW FAC should include purchased power under contract with supply commitments. Consequently, short-term agreements meeting this condition can be included in the FW FAC.

which is the standard billing unit for most customers. The energy rate (ER) is tied directly to AOC and TOC using the following formula:

$$ER = AOC + \tau(TOC - AOC),$$

where τ, a fraction between 0 and 1, is the share of cost savings kept by the utility. In other words, τ is the profit incentive offered to utilities to minimize AOC.

So, for example, if AOC = \$20/MWh, TOC = \$24/MWh, and τ = .25 then the energy rate becomes:

$$ER = \$20/MWh + .25(\$24/MWh - \$20/MWh) = \$21/MWh.$$

The reward to the utility for responding efficiently is given as: τ(TOC - AOC), which in this example becomes .25(\$24/MWh - \$20/MWh) or \$1/MWh.

By lowering operating costs, ratepayers pay \$3/MWh less whereas the utility receives a \$1/MWh profit. As this example implies, the distribution of profits to the utility and cost savings to the ratepayers should be concurrent with the normal billing cycle. If the normal billing cycle is monthly then the energy rate should be adjusted monthly to reflect cost savings. The primary reason for tying the adjustments to the normal billing cycle is to minimize consumption inefficiencies that can occur when energy rates do not reflect actual cost, as happens with delayed and partial pass-through FACs.

The ER formula is essentially the RCOG formula introduced in the previous chapter and likewise can be rewritten as: EQ = Base Retail Rate + Surcharge. The surcharge used to collect the utility profit should be separate from the base retail rate in customer bills to encourage consumption efficiency. A commission can tailor the collection scheme to help achieve particular goals such as aiding low-income households, for example, without distorting consumption or creating a subsidy.

Wholesale Power Sales

The energy rate formula shown above is applicable when the utility is primarily a buyer of purchased power but not a seller. The formula must be modified for utilities in which wholesale power sales account for a sizeable amount of total generation. The justification for modification is twofold: on the one hand, retail customers are entitled to some of the profits earned from wholesale power sales, and on the other the generation of wholesale power can affect AOC to the detriment of retail customers. To ensure that retail customers benefit from wholesale power sales the following formula for the energy rate is suggested:

$$ER = AOC + \tau(TOC - AOC) - \alpha(1 - \tau)(P - AOC),$$

where P is the sale price and α is the ratio of wholesale power sales to retail power sales.

The additional term, $-\alpha(1 - \tau)(P - AOC)$, measures the adjustment to retail energy rates from the profits earned through wholesale power sales. The difference (P - AOC) measures the average profit ($/MWh), the term $(1 - \tau)$ measures the share of profits going to retail customers, and α measures the relative importance of wholesale-to-retail power sales (that is, Q^W/Q^R, where Q denotes the quantity (MWh) of sales). As the importance of wholesale power sales diminish, the value of α approaches zero and the energy rate formula "with-sales" converges to the "no-sales" formula initially presented.

The formula does not separate AOC into retail and wholesale accounts, but instead pools all operating costs. This can have the undesirable consequence of raising retail energy rates since wholesale power sales can raise AOC by an amount greater than the profit share going to ratepayers. This consequence, however, will not occur if the profit share (τ) on wholesale power sales is less than or equal to the profit share on retail sales.[8] In the formula presented, the profit share from both types of power sales is τ and is therefore assumed equal.

Up to this point, wholesale power sales have been treated as a single item although their characteristics vary in practice. Essentially, they are either long term involving committed capacity by the seller and minimum energy takes by the buyer or short term on an "as available" basis. For sales involving committed capacity, only the energy price paid by the buyer should enter the energy rate formula and only the

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[8] See Appendix C for a proof of this claim.

profits from differences in the energy price and AOC should be shared with retail customers through the formula. Any profit from committed capacity should be shared with retail customers through reductions in retail demand charges and determined in a more formal setting such as a rate case. For short-term power sales, the full price should enter the energy rate formula because retail customers are paying for the capacity used to produce the power, and therefore, are entitled to a refund when its actual use is for wholesale customers. Commissions, incidentally, can influence a utility's long-term to short-term wholesale rates through differential profit shares. For example, if a commission wanted to increase long-term power sales, it could raise the profit share on committed capacity above τ, the profit share on short-term sales. However, the profit share on differences in the energy price and AOC from long-term sales should remain at τ or below for reasons discussed above.

In practice, a utility is going to engage in more than one power sale in a given period of time and do so at various prices, implying the term P must represent an aggregate of prices. The value of P should be computed as a weighted average of energy prices paid for wholesale power with the individual weights tied to actual sales. For example, if the utility enters three power sales at the prices \$24/MWh, \$27/MWh, and \$28/MWh and in the amounts 100 MWh, 200 MWh, and 300 MWh, the weight attached to each sale becomes the fractional importance of that sale to total sales. In this example, the weighted price (P) becomes:

$$P = 1/6(\$24/\text{MWh}) + 1/3(\$27/\text{MWh}) + 1/2(\$28/\text{MWh}) = \$27/\text{MWh}.$$

One final note concerns the determining of peak and offpeak energy rates. As long as the utility has both peak and offpeak input weights then corresponding energy rates are easily computed. It is important, however, that the same set of supplier prices be used when calculating peak and offpeak rates, otherwise an implicit form of cross-subsidization can occur. A utility may, for example, want to lower the energy rate to large industrial customers in an attempt to maintain system load. If industrial customers happen to consume electricity mostly during peak time periods, then the utility may calculate the peak rate using the lowest possible set of supplier prices and use the remaining higher prices to calculate the offpeak rate. Although AOC would be unaffected, offpeak energy rates would be excessively high and result in offpeak customers subsidizing peak users.

The Reconciliation Review

The reconciliation review updates the fixed input and supplier weights in response to changes in supply and demand factors. The type of changes which signal the need for a review includes changes in supply sources, large aberrations in facility availability, the inclusion of new capacity through utility investment or competitive bid solicitations, and major changes in long-term purchased power or wholesale power sales. Although there are no firm rules to govern review frequency, commissions should monitor the movement of actual supplier and input weights and compare their values to the fixed weights.

The possibility of a reconciliation review can enable a commission to better motivate efficient behavior. For example, if a utility knows that forced outages or reduced facility availability may prompt reviews, it has an incentive to maintain system reliability to maintain profits. To encourage efficient decisionmaking, the commission could make utilities pay for unscheduled maintenance costs using profits from energy sales. If the maintenance costs exceeded the profits then the utility would request a reconciliation review wherein new supplier and input weights would be optimally determined to meet the current realities.

It is not necessary during a reconciliation review to update all the fixed weights. If the utility contracts with a new coal supplier, for example, it may be prudent for the commission to reset only the supplier weights for coal and leave the remaining weights unchanged. This may be a good policy even though the utility is earning some profits, implying that energy rates would be lower if all fixed weights are readjusted. On the one hand, this gives the commission control over the regulatory costs associated with holding a reconciliation review. A full review in which all weights are readjusted is likely to be more expensive and time consuming than a partial review. On the other hand, holding reconciliations too frequently will undermine the profit incentive and may discourage utility efforts to minimize operating costs. A too-weak profit incentive can turn the FW FAC into a de facto cost-plus FAC with immediate pass-through.

There are three occasions in which a reconciliation review should be automatic: (1) during a rate case, (2) during periods of stagnant fuel prices, and (3) during periods of rapid load changes. Making reconciliation reviews a part of a general rate case only makes good sense since one of the objectives is to determine the utility's revenue requirement, which requires information on operating costs. The fixed weights should be adjusted during periods of stagnant fuel prices simply because current profits would not depend upon current actions but rather upon actions undertaken long ago. It is important to reiterate that one objective of the FW FAC is to reward utilities for aggressively seeking more efficient fuel portfolios, not for inaction. Removing profits during periods of stagnant fuel prices could encourage utilities to pressure suppliers, and in doing so act as a catalyst to lower prices.

As load patterns change so will the utility's operation of its generation facilities. Periodic changes (such as seasonal changes) or more rapid and lasting ones (caused by large industrial customers) will likely cause actual and fixed weights to diverge. Periodic changes are predictable so periodic reviews should occur routinely. By using load and production simulations along with current fuel price and technical information, the commission and utility can determine the optimal input weights for peak and offpeak generation. Although the weights are best guesses and will likely require some further adjustments, it is important that estimated adjustments be made; otherwise the energy rate could become overly high or low resulting in excess profits or losses and in consumption and production inefficiencies. Rapid changes in load growth can also cause actual and fixed weights to diverge significantly because of scale economies or diseconomies. Large industrial customers leaving or joining the system, for example, should signal the need to reevaluate the fixed weights and make necessary adjustments.

Utility Subsidiaries and Self Dealing

One prominent distinction in industrial organization between the electric and natural gas industries is the participation of utility subsidiaries. The role of subsidiaries is scant in the natural gas industry but extensive in the electric industry. Often relationships in the electric industry are vertical wherein the utility completely or partially owns a fuel supplier, an IPP, or a cogenerator. Sometimes, however, the relationship is horizontal; that is, between utilities involving joint ownership ventures. Competitive bidding, the goal of which is to bolster competitive pricing, has produced numerous contracts with subsidiaries, particularly IPPs.[9]

Although subsidiary relationships and affiliations in general can lead to greater economic efficiency, there always exists the potential for self-dealing abuse. Abuse by a utility and its subsidiaries can lead to higher AOC (production inefficiency), to higher energy rates (consumption inefficiency), and to a redistribution of wealth from the ratepayers to the subsidiary (inequities). In short, self-dealing abuse breaks every desirable precept of regulation.

No FAC is immune to the possible effects of self-dealing abuse including the FW FAC, although it is more immune than either the delayed or partial pass-through FAC. Its advantage stems from the fact that TOC is based upon fixed supplier and input weights, which limit the profits to a subsidiary from raising prices. Neither the delayed nor partial pass-through has this built-in advantage; therefore a subsidiary can increase its profits both by increasing prices and the amounts supplied.

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[9] As of June 1989, 100 percent of winning IPP projects had utility affiliations even though affiliated IPPs accounted for just 24 percent of megawatts offered by IPPs. For cogenerators, 19 percent of winning projects were affiliated even though they represented just 8 percent of megawatts offered by cogenerators. Overall subsidiaries accounted for 34 percent of the megawatts in winning bids even though they accounted for must 12 percent of total megawatts offered in competitive solicitations. For more information see: Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program For Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991); and National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation*, Working Paper Number Two (Washington, D.C.: National Independent Energy Producers, March 1990).

Another way the FW FAC can restrict self-dealing abuse is through reconciliation reviews. High prices by subsidiaries will result in subsidiaries being assigned lower supplier and input weights when load and production simulations are used to determine optimal fixed weights. The smaller a subsidiary's rate, the smaller its impact on TOC and therefore on the energy rate. This result holds even though the utility is free to purchase inputs in any amount it desires. The proof of this is easily seen by examining the effect on energy rates from increasing subsidiary prices. Recall the formula for the energy rate is the following when power sales are excluded:

$$ER = AOC + \tau(TOC - AOC).$$

If a subsidiary increases its prices then AOC will change, say, by the amount dAOC, and TOC will change by the amount denoted dTOC. The new energy rate, ER^*, becomes:

$$ER^* = AOC + dAOC + \tau(TOC + dTOC - AOC - dAOC),$$

with the difference (ER^* - ER) being $dAOC + \tau(dTOC - dAOC)$. If the utility purchases from its subsidiary are in the amounts specified by the fixed weights then dTOC=dAOC, which means energy rates are higher by dAOC which is also the increase in the subsidiary's average profit--the increase in total profits is dAOC multiplied by the amount of retail sales. It is equally important to notice that the utility's profit is unchanged. The profit to the utility is given as, $\tau(TOC + dTOC - AOC - dAOC)$, but if dTOC = dAOC then the utility's profit per megawatt becomes, $\tau(TOC - AOC)$, which is the same as prior to the price increase.

Suppose the utility increases its subsidiary purchases in amounts greater than specified by the fixed weights. Under this scenario, the increase in AOC will be larger than the increase in TOC, say, by the amount β. In other words, $(dTOC - dAOC) = -\beta$ which means that $(ER^* - ER) = dAOC - \tau\beta$, which is smaller than dAOC. Since τ is positive, the subsidiary's average profit drops to $dAOC - \tau\beta$, as does its total profit.[10] The utility also fairs worse since its profit per megawatt hour becomes, $\tau(\text{TOC} - \text{AOC} - \tau\beta)$, which is smaller than $\tau(\text{TOC} - \text{AOC})$.

The principal conclusion is that utilities will not purchase supplies from their subsidiary in amounts greater than specified by the fixed weights when the subsidiary increases its prices, although utilities would have no incentive to purchase less either. This tends to make a subsidiary's actual weight unchanging and always close to its fixed-weight value. Consequently, commissions would have a convenient way to detect potential self-dealing arrangements.

Because purchases from a subsidiary will occur in amounts consistent with its fixed weight, a commission can punish a self-dealing abusive utility by holding a reconciliation review and lowering its subsidiary's weight in the FAC. A lower weight results in a smaller effect on TOC, and therefore, on energy rates.[11]

As a caveat, utilities will be cognizant of commission monitoring and may consequently try to cloak abusive self-dealing arrangements. One strategy would be to reduce purchases from a subsidiary by a percentage less than the percentage increase in price. For example, the percentage decrease could be fractionally tied to the percentage increase in price. The final result would be higher energy rates, higher utility and subsidiary profits, and a less efficient generation mix. Another strategy would be for utilities to enter agreements with unaffiliated suppliers with the understanding that higher prices by them will not result in smaller purchases, but rather in higher subsidiary prices. Again the consequences are higher energy rates, higher subsidiary profits, as well as higher profits to nonaffiliates and less efficient generation. This latter strategy poses additional problems to detecting self-dealing abuse since its involves participation by unaffiliated suppliers. The essential problem is in discerning whether price increases by affiliates and nonaffiliates are due to legitimate reasons, such as rising production costs and inflation, or to self-dealing abuses.

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[10] Total profit is $(\text{dAOC} - \tau\beta)\text{Q}$ where Q measures retail sales. As long as Q is constant then average and total profits change in the same direction.

[11] Since actual subsidiary weight will tend towards its fixed weight, $\text{dTOC} = \text{dAOC}$. As the subsidiary's weight approaches zero, $\text{dTOC} \rightarrow 0$ and $\text{ER}^* \rightarrow \text{ER}$.

Suggestions to Control Self-Dealing Abuses

Three suggestions may better control self-dealing abuses and collusion. The first is to tie price increases of a utility subsidiary to some relevant inflation index. This approach works best when the subsidiary is an upstream supplier of raw inputs such as coal. It is best that the inflation index be tailored specifically to the input and be as broad geographically as possible, when feasible. Commissions might wish to avoid using indices which heavily weigh regional input prices since these will be susceptible to the possibility of local collusive arrangements. A geographically broad index is likely to be less susceptible.

The second suggestion, particularly useful when the subsidiary is a power seller, is essentially an extension of the practice of competitive bidding. Before allowing a subsidiary to raise its price or sell to an affiliate, a commission could order a utility to issue a simplified request for proposal (RFP) to all current unaffiliated suppliers giving them the opportunity to bid away the subsidiary's supply. In a sense, this creates a continuous competitive bidding process for current suppliers and could be applied to subsidiaries that supply raw inputs as well as purchased power. This approach is also useful in breaking apart collusive arrangements between affiliated and nonaffiliated entities because once the RFP is issued nonaffiliates will be able to lower their prices and increase their share, both at the subsidiary's expense. Naturally, utilities and their affiliates will be well aware of the potential for such outcomes, yet there is little they can do except, of course, earn profits by becoming more efficient.

The third suggestion to control self-dealing abuses is the reconciliation review wherein supplier and input weights are recomputed to minimize generation costs. When input prices vary an efficient utility would respond so that actual weights diverged from the fixed weights; however, when self-dealing abuses exist the actual weight of an affiliate will diverge little from its fixed weight for reasons previously discussed. Commissions, upon noticing this, should hold a reconciliation review and update the fixed weights. Because self-dealing abuses result in overpriced supplies in comparison to the offers from other suppliers, the recomputed weights of affiliates will be smaller implying their effect on future energy rates and utility profitability will likewise become smaller. The utilities, however, will know this and, therefore, will be less likely to engage in abusive self dealing. Hence, commission alertness coupled with the power to hold a reconciliation review can become an effective deterrent to self-dealing abuses.

CHAPTER 6

THE APPROPRIATENESS OF PGAs AND FACs IN A MORE OPEN MARKET ENVIRONMENT: SOME CONCLUSIONS

We already have reviewed the three traditional criteria for continued use of fuel and purchase gas adjustment clauses to see if they still apply.[1] These criteria constituted a test of appropriateness. The absence of any one of the three constitutes a reason at least to question and perhaps disallow the use of automatic adjustment clauses. The earlier conclusion was that fuel costs still constitute a significant portion of total costs and utilities have little or no control over the cost of fuel unless they buy it from an affiliate. Although fuel prices have not undergone extreme volatility in the recent past, they may in the near future, particularly given the likely effects compliance with the CAAA will have on fuel prices of gas, as well as the price of high- and low-sulfur coal. While some reason may exist to question the continued use of automatic adjustment clauses for fuel given the current lack of price volatility, the original criteria for the continued use of adjustment clauses for fuel still seem to apply.

However, the criteria, while still necessary, are no longer sufficient to test appropriateness in a more open market environment. Markets are more open both because a majority of states have instituted competitive bidding procedures for new power generation and because a more active bulk power exchange market has developed on the wholesale level.[2] Likewise, gas markets are more open with LDCs having a wider choice of gas supplies for gas procurement, including direct gas

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[1] The first criteria is that the item, here purchased power or fuel costs, constitutes a significant or large component of the utility's total operating cost. The second is that the cost changes with respect to that item were volatile and unpredictable. The third criteria is that the purchased items are entirely outside the control of the outside utility.

[2] In general, see Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991).

purchases from the wellhead, firm or interruptible purchases from the pipeline, purchases on the spot market,[3] and purchases on the futures market. In addition, in most states large retail customers have these same purchasing options if they purchase transportation service from the LDC instead of gas sales service. Thus, an LDC must be cautious about its gas purchases or larger retail customers will switch from gas sales service to transportation service. This suggests, of course, that an LDC would have a strong incentive to control its purchase gas costs, whether a PGA exists or not. This incentive is offset in some states by non-cost-of-service (margin)- based transportation service rates designed to make the LDC indifferent as to whether a large industrial customer purchases sales service or transportation service from the LDC. The profit margin earned by the LDC is the same in either case.[4] Also, there will be a tendency for the LDC to use special contracts to price discriminate and to engage in value-of-service or Ramsey pricing. Such special contracts would tend to mitigate an LDC incentive to control its purchased cost of gas.[5]

The more open market environments in both the electric and gas industries suggest that another criteria is necessary for the continued use of automatic adjustment clauses for fuel purchases. This criteria would address the problem of possible perverse incentives that a traditional automatic adjustment clause might have on utility behavior. What should probably be avoided is an automatic adjustment clause that gives the utility either an incentive to engage in anticompetitive activity or no incentive to engage in least-cost purchasing to develop an optimal portfolio of contracts. Examples of an incentive to engage in anticompetitive behavior would

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[3] Generally, see Robert E. Burns, Daniel Duann, and Peter Nagler, *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, OH: The National Regulatory Research Institute, 1989); and Daniel Duann, Robert Burns, and Peter Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, 1989).

[4] This topic is examined in further detail in chapter 4 of Burns, Duann, and Nagler, *State Gas Transportation Policies: An Evaluation of Approaches*.

[5] For a further discussion on how contract prices can be used to price discriminate, see Chapter 3 of J. Stephen Henderson and Robert E. Burns, *An Economic and Legal Analysis of Undue Price Discrimination* (Columbus, OH: The National Regulatory Research Institute, 1989).

include an incentive for a gas LDC to shift costs from noncore customers who are capable of switching to transportation service to core customers who are not. A PGA that allows for cost shifting from an elastic customer class to an inelastic one could be considered anticompetitive if it allows the LDC to saddle core customers with costs that are associated with the cost of serving noncore customers.[6]

An example of an automatic adjustment clause that creates no incentive to engage in least cost purchasing might be a FAC that allows a utility to pass through all purchased power cost that result from competitive bidding. With such a clause a utility might tend to favor competitively bid external construction over its own. Even if the utility were the low cost builder a bias might be created in selecting the projects, possibly tending to favor fuel-intensive projects over capital-intensive ones, because the cost of fuel would virtually be guaranteed to be passed through while capital expenditures would be subject to review before being reflected in base rates. The utility would risk less by building or purchasing power from a fuel-intensive project than a capital-intensive one, all other things being equal.[7]

Therefore, there should be an additional criterion for the continued use of fuel and purchase gas adjustment clauses in a more open market environment; namely that any adjustment clause for fuel purchases creates an incentive for a utility to engage in least-cost fuel or purchase power procurement. If a fuel or purchased gas adjustment clause results in anticompetitive utility behavior or in a utility not procuring least- and best-cost fuel in the more competitive markets, there is good reason to question the continued use of the automatic adjustment clause.

Abolishing purchased gas and fuel adjustment clauses has drawbacks, however. Were FACs and PGAs to be abolished, utilities would have a strong incentive to minimize costs due to the regulatory lag involved in initiating a rate case. However,

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[6] Ibid.

[7] However, allowing pass-through of a winning bidder's fuel cost while not allowing automatic pass-through of capacity cost might be appropriate for a traditional FAC. See Daniel Duann et al., *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988), 92-94.

abolishing FACs and PGAs could lead to distorted price signals in the market. While these might be temporary, utility customers would make consumption and conservation decisions based on price signals that did not reflect current costs, which in turn could lead to over- or underconsumption of gas. In turn, the utility would be purchasing gas based on consumers' faulty consumption decisions, and they might buy more or less fuel or purchase power than would be justifiable economically. To guard against such faulty decisions, automatic adjustment clauses can be redesigned to encourage a utility to engage in least-cost fuel or purchase power procurement.

As shown in earlier chapters, however, most state public service commissions have not altered their PGAs or FACs in any significant manner to accommodate the competitive environments that LDCs and electric utilities operate in today. As such, in most states the FACs and PGAs do not provide LDCs and electric utilities with any significant incentive to find the lowest- and best-cost source of fuel or power. Indeed, the automatic pass-through of most, if not all, of the benefits of a successful fuel or purchase power procurement strategy to ratepayers would provide little incentive (other than weak incentives created by the limited regulatory lag associated with periodic automatic adjustment clauses and by market pressures to hold down prices in retaining market share in markets where alternatives or substitutes exist) for the utility to aggressively seek out low-cost suppliers of fuel or purchase power. Rather, utilities will tend to engage in fuel and purchased power procurement strategies that minimize their risk of having costs disallowed in a prudence review. To minimize the risk of disallowances, utilities might also seek regulatory preapproval of their fuel or purchased power procurement plans.

The authors here propose a fixed-weight PGA and FAC that could be designed to provide a utility with a strong incentive to engage in least-cost fuel and purchase power procurement. Such fixed-weight PGAs and FACs have the advantage of providing appropriate incentives for utilities to engage in least-cost procurement in a more competitive environment, while mitigating distorted price signals that would result were FACs and PGAs abolished. State commissions might, therefore, find it appropriate to reexamine the appropriateness of FACs and PGAs in a more open, competitive market environment and conclude that FACs and PGAs still are appropriate, but only if redesigned to provide utilities with the proper incentive to engage in least-cost fuel or purchased power procurement. Fixed-weight PGAs and FACs might provide commissions with appropriate conceptual models on which redesigned FACs and PGAs could be based.

APPENDIX A

PURCHASED GAS ADJUSTMENT SURVEY

This appendix contains the responses to the NRRI survey of state public utility commissions on purchased gas adjustment clause practices and their implications for ratemaking in competitive environments that was discussed in chapter 4. The survey was conducted during the spring and summer of 1990. Fifty commissions responded. In most instances the responses reported in this appendix are direct quotes from the survey forms. Some minor editing was done occasionally to improve readability.

The authors would like to acknowledge and thank the commission staff members who took the time to respond to this survey. They are: Jerry A. Nohe, Alabama PSC; Steve Pratt, Alaska PUC; Richard V. Kauffman, Arizona CC; Gail Jones, Arkansas PSC; Brian Schumacher, California PUC; Craig Merrell, Colorado PUC; Jeff Honcharik, Connecticut DPUC; Susan B. Neidig, Delaware PSC; Norman D. Reiser and Sharon Logan, District of Columbia PSC; Sherri L. Booye, FERC; Wayne R. Makin, Florida PSC; James Cole, Georgia PSC; Stephanie Miller, Idaho PUC; Tom Kennedy, Illinois CC; Adam King, Indiana URC; Vernon Jordan, Iowa UB; Joe Williams, Kansas CC; Leah Faulkner, Kentucky PSC; Arnold C. Chauviere, Jr., Louisiana PSC; David M. DiProfio, Maine PUC; David Valcarenghi, Maryland PSC; John C. Boll, Massachusetts DPU; Gary Kitts, Michigan PSC; Richard R. Lancaster, Minnesota PUC; C. Keith Howle, Mississippi PSC; David Sommerer, Randy Hubbs, and Bo Matisziw, Missouri PSC; Mike Foster, Montana PSC; Michael L. Greedy, Nevada PSC; George R. McCluskey, New Hampshire PUC; Nusha Wyner and Nueva Elma, New Jersey BPU; Gary Roybal, New Mexico DSC; Ronald H. Streeter, New York PSC; Ray J. Nery, North Carolina UC; Jerry Lein, North Dakota PSC; Marcy G. Kotting, Ohio PUC; Charles Ervin, Oklahoma CC; Gerald A. Lundeen, Oregon PUC; Paul C. Foster, Pennsylvania PUC; Thomas Massaro, Rhode Island PUC; James S. Stites, South Carolina PSC; Dave Jacobson, South Dakota PUC; Hal Novak, Tennessee PSC; Tym Seay, Texas RRC; Dan Bagnes, Utah PSC;

Kathleen Fleury, Vermont PSB; Gail G. Frassetta, Virginia SCC; Kenneth L. Elgin, Washington UTC; Byron Harris, West Virginia PSC; H. A. Meyer and Patti Schulthess, Wisconsin PSC; David M. Mosier, Wyoming PSC.

THE NATIONAL REGULATORY RESEARCH INSTITUTE

SURVEY OF STATE PUBLIC UTILITY COMMISSIONS ON PURCHASED GAS ADJUSTMENT CLAUSE PRACTICES AND THEIR IMPLICATIONS FOR RATEMAKING IN COMPETITIVE ENVIRONMENTS

This survey is being conducted by The National Regulatory Research Institute (NRRI), the official research organization of the National Association of Regulatory Utility Commissioners, as a part of its 1990 Board-approved research agenda.

The results of this survey will be reported in an NRRI report to the state commissions. The purpose of this survey is to identify what current state purchased gas adjustment clause (PGA) practices are and to find what experiences state commissions have had using PGAs in a more open and competitive environment, particularly when local gas distribution companies (LDCs) are engaging in direct gas purchases from producers or when an LDC has implemented a gas transportation policy.

The usefulness and quality of the report is dependent on your response. Individual state responses will be reported in an appendix to the report. Survey respondents will receive a complimentary copy of the final report.

Please mail responses **no later than April 27th** to:

Robert E. Burns
Senior Research Specialist
The National Regulatory Research Institute
1080 Carmack Road
Columbus, OH 43210-1002

If you have any questions concerning the survey, please contact Mr. Robert Burns or Mr. Peter Nagler by telephone at 614-292-9404.

Respondent Information:

Name: ______________________________

Title: ______________________________

Commission: ______________________________

Address: ______________________________

____

City, State, Zip Code: ______________________________

Telephone Number: ______________________________

1. Does your state commission have purchased gas adjustment clauses (PGAs)?
Yes ____ No ____

Responses to this question begin on p. 280 of Volume 2.

1a. If yes, does your commission have a generic rule, order, decision, or case that provides for a uniform PGA for all of the LDCs in your state? Yes ____ No ____ Does your commission treat PGA on an ad hoc basis with each PGA varying from utility to utility? Yes ____ No ____ If your commission has a generic rule, order, or decision which provides for a uniform PGA, please enclose a copy of it with your survey response.

Responses to this question begin on p. 282 of Volume 2.

1b. If your commission has a PGA, how long ago was it established? Recently established (within the last 5 years) ____ Long-standing PGAs (five or more years old) ____ If your PGAs were recently established, please state the reason(s) for their establishment.

Responses to this question begin on p. 287 of Volume 2.

1c. If your commission does not have a PGA, did it at any time? Yes ____ No ____ If it did have a PGA in the past, when was it abolished? ______________ Why was it abolished? In particular, was the PGA abolished because of the effect that it might have on the LDC's gas purchasing decision in a more open gas market? Please enclose any order, opinion, or decision concerning the abolishment of a PGA.

Responses to this question begin on p. 289 of Volume 2.

2. For each LDC in your state, what is its mix of gas supply sources? In other words, what percentage of their purchased gas comes from long-term pipeline sales gas, from long-term (more than one year) gas contracts with producers, from intermediate term (more than one month, less than one year) contracts with producers, and from the spot market (one month or less)? Alternatively, please indicate if your commission does not have this information readily available.

Responses to this question begin on p. 290 of Volume 2.

3. For each LDC in your state, does it own or lease gas storage? Own ____ Lease ___ Neither ____ If it owns or leases, what is the gas storage capacity in Mcf? _______

Responses to this question begin on p. 300 of Volume 2.

4. Does your commission require the LDC to make periodic PGA filings? Yes ___
No ___ How frequently must the LDC make such filings? _______________
What types of data must the LDC include in its submittal to the commission?

Responses to this question begin on p. 306 of Volume 2.

5. Does the commission hold hearings on an LDC's PGA filing? Yes ___ No ___
Are hearings held on every filing or only certain ones? Every filing ___ Only certain filings ___ If only certain filings, which ones are considered?

Responses to this question begin on p. 311 of Volume 2.

6. Is the commission required to hold PGA hearings at any set frequency? Yes ___
No ___ If yes, how frequently? ______________________

Responses to this question begin on p. 314 of Volume 2.

7. Are your commission's PGA hearings public or closed? Public ___ Closed ___
Are purchased gas contracts considered during the hearings kept confidential protection?
Yes ___ No ___

Responses to this question begin on p. 316 of Volume 2.

8. If your commission has a PGA, what costs are allowed in the clause? Please check all that apply.

Gas commodity costs ___
Demand-related costs ___
Pipeline transportation charges ___
Gas take-or-pay liabilities ___
Deficiency-based pipeline gas inventory charges ___
Market-based pipeline gas inventory charges ___
Gas storage costs ___
Administrative costs associated with fuel procurement ___
Other costs (Please specify.) ___

Responses to this question begin on p. 319 of Volume 2.

9. Does your commission require an LDC to use any particular accounting practices?
Yes ___ No ___ If yes, please describe any such requirement.

Responses to this question begin on p. 323 of Volume 2.

10. Please describe any monitoring procedures used to assure that customers are not over- or undercharged for purchased gas in the PGA.

Responses to this question begin on p. 325 of Volume 2.

11. Does your commission's PGA procedure treat cost decreases any differently than cost increases? Yes ___ No ___ Are purchased gas cost decreases passed through to customers as quickly as cost increases? Yes ___ No ___ Please describe any differences in your commission's treatment of cost increases and cost decreases (especially noting any differences that may exist among different customer classes).

Responses to this question begin on p. 329 of Volume 2.

12. Does your commission's PGA procedure include a true-up procedure? Yes ___ No ___ Please describe any true-up procedure used by your commission.

Responses to this question begin on p. 333 of Volume 2.

13. Are there explicit provisions for making refunds to customers, or are overcharges deducted from the next period's PGA charge, or is some other mechanism used to return overcharges to customers? Explicit refund provisions ____ Overcharges offset in the next period's PGA ___ Other mechanism (Please describe.) ___

Responses to this question begin on p. 336 of Volume 2.

14. Is gas purchased directly from the producer by the LDC treated differently in the PGA procedure than gas purchased from other sources, such as the pipeline? Yes ___ No ___ If yes, how?

Responses to this question begin on p. 339 of Volume 2.

15. Is spot gas purchased by the LDC treated differently in the PGA procedure than gas purchased from other sources? Yes ___ No ___ If yes, please describe how.

Responses to this question begin on p. 342 of Volume 2.

16. Are there incentive mechanisms for minimizing purchased gas costs in your PGA? Yes ___ No ___ If yes, please describe in the space below how the incentive provision operates, including any reliability considerations. Please enclose with your survey response any commission rules, orders, or decisions that describe how the incentive mechanism operates.

Responses to this question begin on p. 344 of Volume 2.

17. If your state commission has an incentive mechanism for minimizing purchased gas costs in your PGA, how effective has it been? Can you cite evidence demonstrating its effectiveness? Have there been any difficulties that the commission has encountered in the operation of its PGAs? Please summarize below.

Responses to this question begin on p. 348 of Volume 2.

18. Has your commission addressed the effect that its PGA will have on customer class allocations? Yes ___ No ___ If yes, please explain, with particular emphasis on how core customers are treated.

Responses to this question begin on p. 350 of Volume 2.

19. Has your commission addressed whether its PGA policy encourages bypass? Yes ___ No ___ Has your commission considered whether its PGA policy has encouraged end-user conversion from sales to transportation service? Yes ___ No ___ In particular, has the pass-through of take-or-pay liabilities and gas inventory charges in the PGA been examined with respect to whether or not such policies encourage bypass or increased use of transportation service? Yes ___ No ___ If yes on any of the above, please explain.

Responses to this question begin on p. 353 of Volume 2.

20. How are affiliated gas suppliers treated in PGA proceedings?

Responses to this question begin on p. 357 of Volume 2.

20a. Are there minimum take provisions that affect PGA recoveries from affiliated suppliers? Yes ___ No ___ If yes, what is the commission's policy on true-ups in this situation?

Responses to this question begin on p. 359 of Volume 2.

21. Has the commission addressed how PGAs affect:
Seasonality of gas costs? Yes ___ No ___
Transportation service rates? Yes ___ No ___
Back-up service rates? Yes ___ No ___
Availability of unbundled gas supplies for direct purchase by end-users? Yes ___ No ___
If yes for any of the above, please explain.

Responses to this question begin on p. 362 of Volume 2.

22. Has the commission addressed whether gas escalation provisions are appropriate in a direct LDC-producer gas supply contract? Yes ___ No ___ If yes, please explain.

Responses to this question begin on p. 365 of Volume 2.

APPENDIX B

FUEL ADJUSTMENT CLAUSE SURVEY

This appendix contains the responses to the NRRI survey of state public utility commissions on fuel adjustment clause practices and their implications for ratemaking in competitive environments that was discussed in chapter 3. The survey was conducted during the spring and summer of 1990. Fifty-one commissions responded. In most instances the responses reported in this appendix are direct quotes from the survey forms. Some minor editing was done occasionally to improve readability.

The authors would like to acknowledge and thank the commission staff members who took the time to respond to this survey. They are: Robert T. Duxbury, Alabama PSC; Judith M. White, Alaska PUC; James Matthews, Arizona CC; Lou Ann Westerfield, Arkansas PSC; Bill Y. Lee, California PUC; Craig Merrell, Colorado PUC; Walter Wisnefsky, Connecticut DPUC; Richard A. Latourette, Delaware PSC; Dwayne J. Boyd, District of Columbia PSC; Hugh Stewart, FERC; Jay Taylor and Lee Romig, Florida PSC; Ned Guillebeau, Georgia PSC; Henry Tsuyemura and Norman Lee, Hawaii PUC; Stephanie Miller, Idaho PUC; Thomas Paynter, Illinois CC; Laura User, Indiana URC; Donald P. Judisch, Iowa SUB; Laurie Kelly, Kansas CC; Marvin C. Goff, Jr., Kentucky PSC; Robert E. Crowe, Louisiana PSC; Richard Parker, Maine PUC; O. Ray Bourland III, Maryland PSC; Marla Friedman, Massachusetts DPU; Paul A. Carlson, Michigan PSC; Richard R. Lancaster, Minnesota PUC; B. Leon Browning, Mississippi PSC; Jim Ketter, Missouri PSC; Mark Lee, Montana PSC; Paul Anderson, Nevada PSC; Eugene Sullivan, New Hampshire PUC; Michael Ambrosio, New Jersey BPU; Angela N. Romero, New Mexico PSC; Frank Berak and Mike Santarcangelo, New York State PSC; David F. Creasy, North Carolina UC; Jerry Lein, North Dakota PSC; Ray Strom, PUC of Ohio; Charles Ervin, Oklahoma CC; Roger Colburn, Oregon PUC; Ahmed Kaloko, Pennsylvania PUC; Stephen Scialabba, Rhode Island PUC; A. R. Watts, South Carolina PSC; Bob Knadle, South Dakota PUC; William H. Novak, Tennessee PSC; W. J. Kmetz, Texas PUC; Daniel E. Gimble,

Utah PSC; Ennis John Gidney, Vermont PSB; William F. Stephens, Virginia SCC; Earl E. Melton, West Virginia PSC; Bruce Folsom, Washington UTC; Donna H. Holznecht, PSC of Wisconsin; Mark Stacy, Wyoming PSC.

THE NATIONAL REGULATORY RESEARCH INSTITUTE

SURVEY OF STATE PUBLIC UTILITY COMMISSIONS ON ELECTRIC FUEL ADJUSTMENT CLAUSE PRACTICES AND THEIR IMPLICATIONS FOR RATEMAKING IN COMPETITIVE ENVIRONMENTS

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The usefulness and quality of the report is dependent on your response. Individual state responses will be reported in an appendix to the report. Survey respondents will receive a complimentary copy of the final report.

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Respondent Information:

Name: ______________________

Title: ______________________

Commission: ______________________

Address: ______________________

____

City, State, Zip Code: ______________________

Telephone Number: ______________________

1. Does your state commission have electric fuel adjustment clauses (FACs)? Yes ____ No ____

Responses to this question begin on p. 375 of Volume 2.

1a. If yes, does your commission have a generic rule, order, decision, or case that provides for a uniform FAC for all of the electric utilities in your state? Yes ____ No ____ Does your commission treat fuel adjustment clauses on an ad hoc basis with each FAC varying from utility to utility? Yes ____ No ____ If your commission has a generic rule, order, or decision which provides for a uniform FAC, please enclose a copy of it with your survey response.

Responses to this question begin on p. 377 of Volume 2.

1b. If your commission has an FAC, how long ago was it established? Recently established (within the last 5 years) ____ Long-standing FACs (five or more years old) ____ If your FACs were recently established, please state the reason(s) for their establishment.

Responses to this question begin on p. 380 of Volume 2.

1c. If your commission does not currently have an FAC, did it at any time? Yes ____ No ____ If it did have an FAC in the past, when was it abolished? ________ Why was it abolished?

Responses to this question begin on p. 382 of Volume 2.

2. If your commission has an FAC, what costs are allowed in the clause? Please check all that apply.

Fossil fuel costs ____
Nuclear fuel costs ____
Administrative costs associated with fuel procurement ____
Other costs (please specify.) ____

Responses to this question begin on p. 383 of Volume 2.

3. Please describe how electric purchased power is handled with respect to FACs. Is the energy component of purchased power passed through in the FAC? Yes ____ No ____ Is the demand component of purchased power passed through in the FAC? Yes ____ No ____ Please describe.

Responses to this question begin on p. 386 of Volume 2.

4. Does your commission require the electric utility to make periodic FAC filings? Yes ___ No ___ How frequently must the utility make such filings? __________ What type of data must the utility include in its submittal to the commission?

Responses to this question begin on p. 391 of Volume 2.

5. Does the commission hold hearings on a utility's FAC filing? Yes ___ No ___ Are hearings held on every filing or only certain ones? Every filing ___ Only certain filings ___ If only certain filings, which ones are considered?

Responses to this question begin on p. 395 of Volume 2.

6. Is the commission required to hold FAC hearings at any set frequency? Yes ___ No ___ If yes, how frequently? __________________

Responses to this question begin on p. 398 of Volume 2.

7. Are your commission's FAC hearings public or closed? Public ___ Closed ___ Are purchased power contracts considered during the hearings kept confidential? Yes ___ No ___

Responses to this question begin on p. 400 of Volume 2.

8. Does your commission require the utility to use any particular accounting practices? Yes ___ No ___ If yes, please describe any such requirement.

Responses to this question begin on p. 403 of Volume 2.

9. Please describe any monitoring procedures used to assure that customers are not over- or undercharged for fuel costs in the FAC.

Responses to this question begin on p. 405 of Volume 2.

10. Does your commission's FAC procedure treat cost decreases any differently than cost increases? Yes ___ No ___ Are fuel cost decreases passed through to customers as quickly as cost increases? Yes ___ No ___ Please describe any differences in your commission's treatment of cost increases and cost decreases (especially noting any differences that may exist among different customer classes).

Responses to this question begin on p. 408 of Volume 2.

11. Does your commission's FAC procedure include a true-up procedure? Yes ___ No ___ Please describe any such true-up procedure used by your commission.

Responses to this question begin on p. 411 of Volume 2.

12. Are there explicit provisions for making refunds to customers, or are overcharges deducted from the next period's FAC charge, or is some other mechanism used to return overcharges to customers? Explicit refund ___ Overcharges offset in the next period's FAC ___ Other mechanism ___ Please describe.

Responses to this question begin on p. 414 of Volume 2.

13. Are there incentive mechanisms for fuel cost minimization in your commission's FAC? Yes ___ No ___ If yes, please describe in the space below how the incentive provision operates. Please enclose any commission rules, orders, or decisions that describe how the incentive mechanism operates with your survey response.

Responses to this question begin on p. 417 of Volume 2.

14. If your state commission has an incentive mechanism for fuel minimization in your FAC, how effective has it been? Can you cite evidence demonstrating its effectiveness? If so, please summarize below.

Responses to this question begin on p. 420 of Volume 2.

15. Has your commission addressed the regulatory implication of your FAC for ratemaking in a more competitive electric power market? Yes ___ No ___ If yes, has it addressed the implications of passing through capacity costs contained in purchased power as more IPPs and QFs come on line? Yes ___ No ___ Has it addressed the effect of these costs on customer class cost allocations? Yes ___ No ___ If yes for any of the above, please explain.

Responses to this question begin on p. 422 of Volume 2.

16. Has your commission addressed whether its FAC procedure encourages self-generation? Yes ___ No ___ If yes, please explain.

Responses to this question begin on p. 426 of Volume 2.

17. Is purchased power from an affiliated QF or IPP treated any differently than other fuel costs in your commission's FAC procedure? Yes ___ No ___ If so, how? In particular, what are the commission's true-up procedures in these situations?

Responses to this question begin on p. 428 of Volume 2.

18. Has your commission addressed what kind of electric fuel adjustments, if any, are appropriate for power purchased from QFs and IPPs that win competitively bid power supply contracts? Yes ___ No ___ If so, what did your commission conclude?

Responses to this question begin on p. 430 of Volume 2.

APPENDIX C

MATHEMATICAL PROOFS FOR FW FAC

Appendix C contains several proofs for some of the claims in Chapter 5 on the fixed-weight FAC.

The Legend

TOC	= Target Operating Cost		dTOC	=	change in TOC
AOC	= Actual Operating Cost		dAOC	=	change in AOC
π	= Profits w/o power sales				
π^W	= Profits with power sales				
Q	= Retail sales		α	=	Q_W/Q
Q_W	= Wholesale sales				
τ	= Retail profit share		τ^W	=	Wholesale profit share
MC	= Marginal costs				
P	= Price of wholesale power				

Proof 1: **The effect of purchasing power at prices above system marginal cost**

Assumption: Assume Q = 1 and P > MC, that is, self generation is cheaper than economy power.

$\pi^0 = \tau(TOC - AOC - MC)Q$ "profit when self generating"

$\pi^1 = \tau(TOC - AOC - P)Q$ "profit when purchase power"

$\pi^1 - \pi^0 = -\tau(P - MC)$ but P > MC by assumption so,

$\pi^1 - \pi^0 < 0$ implying $\pi^1 < \pi^0$

Conclusion: The fixed-weight FAC penalizes a utility for purchasing power at prices above system marginal cost by lowering its profits.

<u>**Proof 2**</u>**:** **The effect on utility profit and ratepayer energy rates when the profit share on wholesale power sales exceeds the profit share on retail power sales.**

Assumption 1: Let dAOC > 0, that is, wholesale power sales result in a higher level of operating costs.

$$\pi^W = \underbrace{\tau(\text{TOC - AOC - dAOC})}_{\text{"average retail profit"}} + \underbrace{\alpha\, \tau^W (\text{P - AOC - dAOC})}_{\text{"average wholesale profit"}}$$

$$\pi = \tau(\text{TOC - AOC}) \quad \text{"average profit w/o wholesales"}$$

(For simplicity, the profit formulas above have been divided by Q, the level of retail sales, and therefore are averages.)

$$\pi^W - \pi = -\tau\text{dAOC} + \alpha\tau^W(\text{P - AOC - dAOC})$$

$\pi^W > \pi$ requires that (P - AOC - dAOC) > (τdAOC/$\alpha\tau^W$)

Assumption 2: Assume the utility engages in a profitable wholesale power sale such that:

$$\pi^W - \pi = (\text{P - AOC - dAOC}) - (\tau\text{dAOC}/\alpha\tau^W) = (\delta\text{dAOC}/\alpha\tau^W) > 0 \ (\delta > 0)$$

Notice that δdAOC = $\alpha\tau^W$ (P - AOC - dAOC) - τdAOC where the first term on the right hand side is the average profit from wholesale power sales weighted by α (the ratio of wholesale to retail sales) and the second term is the average profit lost on retail power sales because of higher operating cost. The variable δ, therefore, can be interpreted as the net average profit on higher operating costs after dividing through by dAOC.

The critical question is what effect does $\tau^W \neq \tau$ have on the energy rate (ER) of ratepayers. The answer is as follows:

$$ER^W = AOC + dAOC + \tau\,(TOC - AOC - dAOC) - \alpha(1 - \tau^W) \times (P - AOC - dAOC)$$

$$ER = AOC + \tau(TOC - AOC)$$

$$ER^W - ER = dAOC - \tau dAOC - \alpha(1 - \tau^W)(P - AOC - dAOC)$$

But $(P - AOC - dAOC) = \dfrac{(\tau + \delta)dAOC}{\alpha\tau^W}$.

$$ER^W - ER = (1 - \tau)dAOC - \left[\frac{(1 - \tau^W)(\tau + \delta)dAOC}{\tau^W}\right]$$

$$ER^W - ER = \left[\frac{\tau^W - \tau) + \delta(\tau^W - 1)}{\tau^W}\right]dAOC$$

Claim 1: If $\tau^W = \tau$ then $ER^W < ER$, that is, if the profit shares are identical then a profitable sale by the utility results in a lower energy rate.

Proof: Let $\tau^W = \tau$ then $ER^W - ER = \left[\dfrac{(\tau - \tau) + \delta(\tau - 1)}{\tau}\right] dAOC$

$$ER^W - ER = \left(\frac{\delta(\tau - 1)}{\tau}\right) dAOC < 0 \text{ since } \tau < 1$$

Claim 2: If $\tau^W < \tau$ then $ER^W < ER$.

Proof: Let $\tau = \tau^W + \epsilon$, $\epsilon > 0$, then

$$ER^W - ER = \left(\frac{(\tau^W - \tau^W - \epsilon) + \delta(\tau^W - 1)}{\tau^W}\right) dAOC$$

$$ER^W - ER = \left(\frac{-\epsilon + \delta(\tau^W - 1)}{\tau^W}\right) dAOC < 0$$

Claim 3: If $\tau^W > \tau$ then $ER^W < ER$ only if the average profit on higher operating costs (δ) exceeds the difference in profit shares ($\tau^W - \tau$) divided by share of profits on wholesale power sales that are returned to ratepayers ($1 - \tau^W$).

Proof: $ER^W - ER \lesseqgtr 0$ if $(\tau^W - \tau) + \delta(\tau^W - 1) \lesseqgtr 0$

So $ER_W < ER$ if $(\tau^W - \tau) + \delta(\tau^W - 1) < 0$ or when $\delta > \dfrac{\tau^W - \tau}{1 - \tau^W}$

For example, let $\tau^W = .5$ and $\tau = .4$ so that $\tau^W > \tau$ then

$$\delta > \frac{.5 - .4}{1 - .5} = \frac{1}{5} = 20\%.$$

As a result, ratepayers only benefit (lower ER) if δ, the net return on the additional operating cost, exceeds 20 percent; otherwise $ER^W > ER$ making ratepayers worse off.