AN EVALUATION OF
A FUEL ADJUSTMENT CLAUSE
FOR THE ALABAMA POWER COMPANY

prepared for

THE ALABAMA PUBLIC SERVICE COMMISSION

by

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in behalf of

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FOREWORD

This report was prepared by J. W. Wilson and Associates, Inc. for The National Regulatory Research Institute (NRRI) under Contract No. EC-77-C-01-8683 with the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the contractor and do not reflect the opinions nor the policies of either the NRRI or DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

The NRRI appreciates the cooperation of the Alabama Public Service Commission with the contractor in preparing this study and for their permission to make this information available to others interested in regulatory affairs.

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TABLE OF CONTENTS

I. Introduction

Throughout the nation, as in Alabama, the prices charged for electricity by privately owned electric utilities are regulated by state public utility commissions. When an electric utility such as the Alabama Power Company wants to raise its prices, it must file a set of rate schedules with its regulatory authority, showing the new prices that it proposes to charge. These schedules show the rates and charges for electric service, and also explain any other terms and conditions under which electricity is furnished by the utility. New rates proposed in this manner by a utility typically do not go into effect until approved by the regulatory commission, or as otherwise provided by law.[1/]

Before approving a utility's request for a rate increase, the commission generally institutes an investigation and hearing into the need for higher rates. This process of investigation and hearing is called a general rate case. It involves the presentation of testimony and other evidence by the utility company, arguing its need for the higher rates. Supportive or opposing testimony may also be submitted by the staff of

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[1/] In some states, new rates requested by a utility can go into effect shortly after the rate increase application has been filed with the state regulatory commission, with the increased revenues collected being subject to refund of any amounts found later by the commission to be excessive.

the commission and by intervenors, such as the state's consumer advocate[2] or the utility's large customers.

After all the parties to the rate case have been heard and cross-examined by those opposing their position, the commission examines the complete record of the proceeding and renders its decision with respect to the proposed rate change. The commission may accept the proposed rates as filed; reject them entirely, thus continuing the old rates in effect; or, as is usually the case, permit the utility to increase its rates by some part of the total amount originally requested.

Each general rate investigation is a major undertaking for a public utility commission, and it generally extends over a period of at least several months. The substantial effort and time required for a general rate investigation are needed in part to satisfy the procedural requirement that the interested parties (including the company, the commission staff, and any intervenors who wish to participate) all have adequate opportunity to prepare their evidence and arguments and to be heard. Even more important than the procedural requirements are the scope and complexity of the issues that may be considered in a general rate investigation.

In the broadest terms, there are two principal issues to be decided in a general rate investigation: the rate level

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2/ In Alabama and in several other states, the Attorney General has the responsibility of acting as the consumer advocate in utility rate cases.

and the rate structure. The rate level is the amount of money that the utility needs to collect from its customers to cover the total cost of furnishing electricity service, including a fair return on the capital invested in the business. This sum is sometimes called the revenue requirement. The rate structure issue involves the determination of how the total revenue requirement shall be distributed among the company's many customers. This may involve allocation among customer classes such as residential customers and large industrial customers, and it may also involve allocations between peak and offpeak consumption or allocations within a class based on customer usage and demand characteristics.

Because of the complexity and length of a complete general rate investigation, new rates, once established, are likely to remain in effect for at least a full year before they are superseded by the final decision that may result from the next succeeding rate investigation. In times of rapidly changing electric utility costs, the time required for a complete general rate investigation can result in "regulatory lag"--that is, rates which reflect cost circumstances as perceived at the time of the last rate case but out of line with current cost conditions.

In an effort to reduce the potential for regulatory lag resulting from the time and complexity of complete general rate investigations, attention has turned to the use of interim adjustment procedures for changing electric utility rates between complete general rate investigations. The purpose of these interim adjustment procedures is to permit prompt changes in electric utility rate levels, in accord with changes in some of the more volatile cost elements, without the necessity of a complete rate investigation.

This report explores the policy considerations relating to the use of one such interim adjustment procedure--fuel cost adjustments, which are the most common interim adjustments used for electric utilities. The report first explains generally how an interim adjustment procedure works and outlines the general advantages and disadvantages of interim adjustment procedures.

Turning in more detail to specific fuel cost adjustment procedures, two principal approaches to fuel adjustments are presented. The advantages and disadvantages of these two approaches are discussed in detail, and some problems in implementing fuel adjustments are identified. The report also discusses how potential problems can be minimized and how cost efficiency incentives can be maintained when fuel adjustment procedures are utilized. The final section of the report describes the Alabama Power Company's fuel and purchased power adjustment clause as it is presently approved and implemented by the Alabama Public Service Commission. Several suggestions for improvement are offered based on the foregoing analysis of optimal interim adjustment procedures.

II. Interim Fuel Cost Adjustments

A fuel adjustment clause is a provision in an electric utility's rate schedule which permits the raising or lowering of electric utility rates in response to changes in the fuel (and, frequently, purchased power) cost element of a utility's complete cost of service, without regard to changes in any of the other cost elements. The essence of the fuel adjustment clause procedure is that attention is focused only on those fuel and purchased power costs, which the regulatory commission has already determined require interim attention between complete general rate investigations. By adopting such a procedure, regulatory authorities can permit rate adjustments to be made in response to changes in fuel and purchased power costs, without the necessity for a general investigation of all of the cost elements that would normally be considered in a complete rate case.

Fuel costs are now subject to special rate adjustment procedures in most regulatory jurisdictions because they are such a large fraction of the total cost of electric service, and also because they may be very volatile. Moreover, interim rate adjustments for fuel cost changes are highly feasible, because electric utilities maintain detailed records on fuel purchases, including fuel type (oil, coal, etc.), quantity (barrels, tons, etc.), price, heat content (Btu's per ton, etc.), and on the electricity generated therefrom. Like the other accounting records of electric utilities, these data are maintained monthly, and they are available typically within fifteen to forty-five days after the end of each month for use in the calculation of interim fuel cost changes.

The use of the fuel adjustment clause procedure involves three steps:

(1) Determination of the specific fuel and purchased power cost elements for which interim adjustments are to be made.

(2) From time to time, as changes in these costs occur, determination of the dollar impact of these cost changes on the total cost of service.

(3) Translation of the total cost change into a rate change of an amount sufficient to effect a corresponding revenue change.

Advantages and Disadvantages of Interim Adjustment Procedures

Interim adjustment procedures offer one major advantage: because they are focused on only some of the many elements in the total cost of service for an electric utility, they permit more prompt and frequent adjustment of electric utility rate levels in response to changes in the costs on which they are focused than is possible through the process of complete rate investigations. This advantage is an important one, with the following consequences:

- If the costs subject to interim adjustment are moving in the same direction as the total costs of the utility, then the interim adjustment process helps keep the overall rate level in touch with the total cost level of the utility, and therefore it reduces the needed frequency of complete rate investigations.

- The interim adjustment process permits regulatory resources to be concentrated on those cost elements that are large, highly volatile, or otherwise important; and it conserves resources that would otherwise be used in repeated study, in complete rate investigations, of other cost elements not requiring such frequent regulatory attention.

- Interim adjustment procedures permit a prompt rate adjustment at times when extremely large changes in one or another of the costs of service make some interim adjustment in the rate level essential.

The first two beneficial consequences of using the interim adjustment process are simple procedural benefits. They are not glamorous, but they indicate a substantial contribution toward reducing regulatory lag. The third beneficial consequence is relevant only in extreme circumstances such as the fuel price increases of 1974. In such circumstances, an immediate rate increase may be essential. In instances where the immediate revenue needs of the utility are not met by established interim adjustment procedures, some commissions have granted emergency rate relief. Emergency relief is often granted near the beginning of a complete rate investigation, and the dollar amount of the relief is ordinarily determined by the commission without any explicit or reported calculation of the actual immediate needs of the utility. The establishment of interim adjustment procedures would help rationalize this process.

Against these advantages, interim adjustment procedures also involve a number of disadvantages:

(1) Since interim rate adjustments are based upon consideration of some, but not all the costs of an electric utility, it is possible for the rate adjustments to go in one direction while the total costs are moving in the other direction. This result is obviously worse than no interim rate adjustment at all.

(2) Even when not perverse, as in (1), interim adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering the offsetting factors, such as productivity improvements that reduce total cost increases. (In principle, the opposite bias could also be found, but in fact it has not appeared to be a problem.)

(3) Interim adjustment procedures may tend to weaken incentives.

(4) Interim adjustment procedures may distort incentives.

(5) Interim adjustment procedures, especially automatic ones, have been and may continue to be subject to abuse by the utilities to which they apply.

These disadvantages are considered in turn.

Electric utility rate levels have traditionally been designed to cover the total cost of service. Rate structures have generally been designed to reflect cost structures, but it has not been the usual practice to earmark any type of revenues to cover specific cost items. Viewed in this light, the purpose of interim adjustment procedures is to help the rate level keep pace with costs, whether they are going up or down.

The first problem with interim adjustment procedures is that they are concerned only with some, but not all, of the total costs of an electric utility; and there is no assurance that the costs for which adjustments are made must necessarily be moving in the same direction as total costs. If the costs for which interim adjustments are made go in one direction, while total costs go in the other, then the interim adjustment process will cause the costs and rate level to diverge faster than they would if there were no interim adjustments. For example, fuel costs in some areas fell during 1976, yet total costs of electricity supply continued to rise. In these circumstances, the operation of interim fuel adjustment procedures exaggerated the lag of the rate level behind rising costs. This example shows that interim adjustment procedures are not always helpful in keeping rate levels aligned with total costs.

A second potential problem with interim adjustment procedures is that they may be biased to register changes in those cost elements that are most subject to increase, but not to reflect factors that may tend to make costs decrease. For example, automatic adjustment clauses have in the past been designed to register fuel prices, taxes, and wage rates, but they have given little attention to productivity or efficiency. So long as there are any improvements at all in productivity and efficiency, average costs will increase less rapidly than the prices of the inputs that a utility buys.

An interim adjustment procedure that comprehensively registers inflation in the prices of the inputs bought and used by a utility, but that does not reflect productivity and efficiency gains, will therefore invariably overstate the upward movement of costs. In times when productivity gains and improvements in efficiency come rapidly but the rate of price inflation is relatively slow, as in much of the 1950's and 1960's, unit costs of electricity may actually be falling despite the existence of modest inflation.

The third problem with interim adjustment procedures is that they may tend to weaken the incentives for a utility to supply electricity at minimum cost. If the rate level is fixed, then it is the shareholders who stand to gain or lose the full amount of any cost savings or increases, at least until the next rate case, when the rate level is reset to the then prevailing cost level. If instead there are interim adjustment procedures to change the rate level quickly in response to cost changes, then these gains and losses are shifted very quickly to the ratepayers; and management has less incentive to minimize costs than when the benefits go to the shareholders. This argument in favor of regulatory lag has been espoused by Alfred E. Kahn, former Chairman of the New York Public Service Commission, and by others.[3/]

[3/] Alfred E. Kahn, <u>The Economics of Regulation: Principles and Institutions</u> (New York: John Wiley & Sons, Inc., 1971), Vol. II, p. 48.

In addition to weakening the incentive for a utility to minimize the outlay on items subject to interim adjustment, the existence of an interim adjustment procedure may distort the incentive for a utility to select the most efficient and least costly combination of inputs for supplying electricity. Specifically, when all costs are rising, the utility may have an incentive to use relatively more of the input for which interim rate adjustments are possible, and less of the input for which there is the greatest regulatory lag in recovering cost increases through higher rates. This point is made most often with respect to fuel adjustment procedures, which, it is argued, provide an incentive for utilities to build less capital-intensive generating plants that use petroleum fuels, rather than the more capital-intensive generating plants that use coal or nuclear fuel.4/

4/ In 1962, Averch and Johnson showed that a profit-maximizing utility would increase its plant investment above the most efficient level, and use less of other inputs such as labor or fuel if it were able to earn a rate of return on investment in excess of the cost of raising capital. Since excess returns were possible during most of the 1950's and 1960's, primarily because costs were falling and regulatory lag thus worked to the advantage of the utilities, this so-called Averch-Johnson effect was believed to have been an incentive for inflating the rate base. In the 1970's, many utilities have been unable even to earn a return equal to the cost of capital, and this same principle therefore suggests an incentive to restrict investment below the most efficient level. And this incentive is strengthened by automatic adjustment procedures that reduce the regulatory lag for recovering increases in other costs such as fuel, while leaving intact the regulatory lag in recovering increased capital costs.

The final disadvantage of interim adjustment procedures, especially the automatic ones, is that they have been and may continue to be abused by the utilities to which they apply. In some instances, the interim adjustment process has been badly designed, yet still received the regulatory approval necessary for its use. In other instances, the utility has either manipulated the transactions to which the interim cost adjustments apply, or simply misstated the facts, taking advantage of the absence of scrutiny by the regulatory authority. With regard to the latter problem, the solution is increased vigilance by the regulatory authority. And indeed, it is coming to be recognized that interim adjustment procedures are not a device for abdication of regulatory responsibility, as they may often have been in the past, but rather are a device enabling the regulatory authorities to focus their attention on those costs that are changing most rapidly and therefore are most in need of careful scrutiny. With regard to the former problem, the proper response to badly designed interim adjustment procedures is improvements in design, not necessarily the elimination of interim adjustments altogether. Since most of the furor over abuse of interim adjustment procedures relates to the fuel adjustment process, the presentation in the next four sections of this volume is appropriate as a guide to how a carefuly designed interim adjustment procedure can minimize the danger of abuse by the utilities to which it applies.

Implementing Interim Fuel Adjustments

On a procedural level, it is important to emphasize that the determination of which cost elements to make subject to interim rate adjustments is a determination that must be made in advance of and outside of the adjustment process itself. The reason is that the value of the interim adjustment procedure lies largely in its focus on changes in specific cost elements without the need for a general rate investigation. In that regard, attention can properly be focused on certain costs, while ignoring all of the others, only after it has first been determined which costs warrant this special attention.

An important consideration, therefore, is that there is not likely to be ready agreement about which cost elements require interim adjustment and which do not. Utility companies are likely to want interim adjustments for those factors most responsible for increasing total costs, such as inflation in the prices of the inputs they purchase; whereas consumer groups are likely to want consideration of those factors that tend to reduce costs or offset inflation, such as improvements in productivity. To make the interim adjustment process work effectively, a regulatory commission must establish and enforce a firm policy defining the cost factors that may be considered in this process. If the commission fails to do so, interim adjustment proceedings will degenerate into complete rate investigations, and they will no longer serve the purpose for which they were designed.

Because the issues are controversial and complex, the determination of which cost elements may properly be the subject of interim adjustments is itself a decision which may require investigation and hearing. Such an investigation and decision could be the subject of a separate general or rule-making proceeding, or the adoption of specific interim adjustment procedures for a particular company may result from their consideration in a general rate case involving that company.

When a fuel cost adjustment policy is established, it must specify the events that will trigger the adjustment process. This trigger may be simply the passage of time, as with a monthly or other periodic review of fuel costs; or it may be a specified event, such as a fuel cost change of a particular magnitude.

When the triggering event occurs, the next step is to calculate the changes in the costs for which interim adjustment is allowed. If the regulatory commission is able to prescribe a precise method for calculating the amount of the interim cost change at the time it establishes its interim adjustment policy, then this step may not involve subsequent controversy or the need for an extensive hearing or investigation. Such an adjustment procedure would be more or less automatic. On the other hand, a commission may wish to exercise its discretion more directly in limiting the scope of interim cost adjustments, without prescribing a standard formula in advance which would automatically dictate how all adjustments should be calculated. This type of discretionary interim adjustment will still require investigation, hearing, and decision by the commission, though it may be much simpler and faster than a complete rate investigation. Because the differences between automatic and discretionary interim cost adjustments are so important, this question is discussed shortly under its own heading.

The second and third steps of the interim adjustment process require the calculation of the total dollar amount by which a utility's cost of service (and thus its revenue requirement) is affected as a result of interim changes in the cost elements that are to receive special rate treatment, and the translation of such changes in the revenue requirement into changes in rates. This final step has received comparatively little attention, because it has generally been the practice in most jurisdictions to adjust all rates upward or downward uniformly on a per kilowatt-hour basis applied equally to all energy billed by the company.

For fuel, such a uniform charge or credit per kilowatt-hour may be roughly appropriate, but ideally there should be some special provisions for customers taking service at high voltages, where energy losses are less, and during offpeak hours, when fuel costs tend to be lower. These are essentially rate structure design considerations, but it is appropriate for regulators to be aware of such considerations in connection with interim adjustment procedures as well.

Automatic or Discretionary Procedures

Historically, most electric utility interim cost and rate adjustment procedures have been automatic. This means that the amount of the rate adjustment was calculated by the utility in accord with a formula stated in the tariff and approved by the regulatory commission in advance. Automatic fuel adjustment clauses date back to World War I, and they have remained in effect in many jurisdictions for many years without creating substantial controversy.

This situation changed when fuel prices began rising rapidly in 1974, initially as a result of the OPEC oil embargo and subsequently as other economic and political forces served to push all fuel costs to even higher levels. Nationwide electric utility rates increased by billions of dollars through the operation of automatic fuel adjustment clauses in response to these fuel cost increases. Rate increases of this magnitude attracted national attention to automatic fuel adjustment clauses, and, as a result, they were abolished in several states, either by legislative or regulatory action. In some of these states, the entire notion of interim rate adjustments reflecting fuel cost changes was done away with; but in others, the procedural change related only to the automatic nature of the fuel adjustment process not to the principle of making interim rate changes reflecting fuel cost changes. Thus it was determined that interim cost adjustment procedures could be discretionary as well as automatic. However, while discretionary interim adjustment procedures permitted greater frequency and restricted scope of interim investigations, they did not remove the need for significant commission oversight.

The experience since 1974 indicates that discretionary fuel adjustment procedures are workable in the states that have tried them. This, however, does not mean that interim adjustment procedures should invariably be discretionary rather than automatic. Discretionary procedures, which require significant action by the regulatory commision, do have their costs, including the additional burden that they place upon the staff and resources of the commission. It is enough, therefore, merely to note that both automatic and discretionary adjustment procedures are feasible; and the choice between these two methods should be left to the judgment of the regulatory commission based on factual circumstances at hand.

Using Proxies or Actual Costs

Interim fuel cost adjustment procedures generally reflect the fuel costs actually incurred by an electric utility. However, it is frequently noted that a prompt and complete adjustment of rates to compensate for changes in costs destroys the incentive for utilities to control their costs effectively. It has therefore been argued that interim rate adjustments should be based, at least in part, upon a proxy (which is clearly beyond the control of the regulated utility) for the fuel cost inflation that the utility is facing. This, it is argued, would enhance efficiency incentives in that the utility could either under or over recover its cost depending on how efficiently it was able to deal with a rising cost environment.

The use of proxies has not won substantial acceptance in the electric utility industry, but is has begun to appear in some telephone rate regulation, and it merits further consideration by regulatory bodies.[5]

Elements of Fuel and Purchased Power Cost

A utility's total fuel and purchased power expense depends upon four factors:

(1) the prices that it pays for fuel and purchased power;

(2) the quantities of fuel that must be burned in each of the utility's plants to generate one kilowatt-hour of electricity (these quantities are called the "heat rates");

(3) the proportions in which the total requirement for electricity is provided by the different generating plants and purchases (called the "generation mix"); and,

(4) the quantity of electricity required to be generated.

The import of fuel prices is obvious, but each of the other three factors deserves some brief comment.

Heat rates are important for two reasons. First, the heat rate is the technical efficiency of a generating plant in con-

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[5] For more detail and some case references, see Ralph E. Miller, "Commentary on Application of Productivity Measurement," in Walter L. Balk and Jay M. Shafritz, eds., Public Utility Productivity: Management and Measurement (Albany: New York State Department and Public Service, 1975), pp. 234-235.

verting fuel into electric energy. A lower heat rate, meaning less fuel used per kilowatt-hour of electricity, corresponds to greater efficiency and to reduced fuel expense. Second, heat rates are important because they are not the same at all generating plants. Newer plants generally have lower heat rates than older ones, although the environmental policies of the past few years have slowed the rate of improvement. Also, generating units used for peaking purposes, such as gas turbines, generally have higher rates than baseload units, which are more efficient. The existence of these differencs in heat rates is one reason why the generation mix is important.

If costs were the same for all fuel purchases and if the fuel cost per kilowatt-hour were the same for all generating plants on a utility's system, the total fuel and purchased power cost would not depend upon which plants were used to generate the required total amount of electricity. But fuel cost per kilowatt-hour is not the same at all plants. Hydroelectric plants have zero fuel cost, though their use is obviously limited by the available water. Nuclear plants have much lower fuel costs per kilowatt-hour than fossil-fuel plants (but much higher capital costs) because current nuclear fuel prices are much lower than fossil-fuel prices for the equivalent amount of heat energy. And even among fossil-fuel plants, fuel costs differ because of differences in fuel prices and heat rates. Prices are different for the different types of fuels--coal, oil and natural gas--and also because of differences in transportation cost and sulfur content, among other factors.

Since fuel costs per kilowatt-hour are different at different plants, a utility can reduce its total fuel cost by obtaining more electricity from plants with lower fuel costs per kilowatt-hour, and less electricity from plants with higher fuel costs per kilowatt-hour. In this way, the generation mix can have an important effect on total fuel costs.

The final factor affecting total fuel expense is the total power supply required. Power supply, which includes net generation plus purchases, differs from sales of electricity primarily by system line losses. Losses are typically 5 - 12 percent of total power supply, depending largely upon the type of service territory, and they average about 7 percent nationwide. If a utility can reduce its losses, its fuel cost per kilowatt-hour sold decreases even though its fuel cost per kilowatt-hour generated is not affected.

Changes in Fuel Cost Per Kilowatt-hour

Fuel and purchased power cost per kilowatt-hour changes whenever one of the four elements of total fuel expense changes.

Fuel prices depend largely upon the fuel markets, and as such they are subject to large variability, often unexpected. They may also depend upon the fuel purchasing practices of the utility, because contract terms are different from spot prices. In times of unexpectedly rapid fuel price inflation, fuel prices may also depend upon how aggressively utilities seek to enforce their contractual rights in the face of refusals of suppliers to deliver, as occurred in 1974 and 1975. Some utilities also purchase fuel from affiliates, and thus they may exercise some control over these prices.

Heat rates are more in the control of the utilities than fuel prices, but the heat rate for a single generating unit usually changes very little, except when modifications to the plant are made for environmental or other reasons.

The generation mix has become an important variable affecting fuel costs per kilowatt-hour. Fuel costs range from zero for hydroelectric power up to 2 cents or more per Kwh for fossil generation. Among the factors that affect the generation mix, and through it the average fuel cost per kilowatt-hour, three are extremely important:

(a) hydrologic conditions affecting the availability of water for hydroelectric power;

(b) unavailability or restricted availability of existing nuclear units, owing to refueling, maintenance, or safety requirements; and,

(c) outages, especially for unscheduled maintenance of large, efficient baseload steam generating units.

When more water than usual is available, fuel costs go down; when less water is available, they go up. When nuclear and efficient fossil-fired plants are available, fuel costs are lower than when these plants are out of service entirely, or are able to operate only at a fraction of their designed capacity.

Changes in the loss factor may also result from changes in the configuration of the transmission and distribution system, including those that result from temporary malfunctions or damage.

Types of Fuel Adjustment Procedures

There are two major types of fuel adjustment procedures that have gained wide acceptance:

- fuel price adjustments, in which rate changes are made to correspond only to the impact of fuel price changes on total fuel costs, disregarding the impact of the other elements of total fuel costs; and,
- fuel cost adjustments, in which rate adjustments are made to correspond to the full amount of the change in total fuel cost per kilowatt-hour of electricity sales, however that fuel cost change may occur.

In a typical fuel price adjustment procedure, the price of all electricity sales is adjusted upward or downward by a fixed amount (in mills per kilowatt-hour) for each unit change in the price of fuel (typically measured in cents per million Btu's). For example, a utility may have a retail fuel adjustment clause in which the rate is adjusted by, say, 1/10 mill (.01¢) per kilowatt-hour for each increase or decrease of 1¢ per million Btu in the cost of fuel to the generating stations that supply it with electricity. The proper size of the fixed adjustment factor in this case depends upon the generating mix, heat rates, and loss factor of the utility in question; and it is ordinarily determined with reference to the base period conditions of these factors, usually those observed in the test year of the rate case in which the fuel adjustment procedure is established.

In a typical fuel cost adjustment procedure, the size of the rate adjustment is simply the change in the total fuel cost per kilowatt-hour of sales from the base level embodied in the base rates to the current period. The regulations of the Federal Energy Regulatory Commission (formerly the Federal Power Commission) require that fuel clauses in electric rates for wholesale sales for resale be of this form (if a fuel clause is used at all).

In addition to these two major types of fuel adjustment procedures, there are also a large number of minor variations. Some fuel adjustment procedures have permitted rate changes equal only to the change in fuel cost per kilowatt-hour generated, rather than the cost change per kilowatt-hour sold. Since generation exceeds sales, because of losses, the effect of this provision is to limit the amount of rate adjustment to a large fraction, but not quite the entirety of the change in fuel cost per kilowatt-hour sold. Other refinements relate to the way in which fuel costs are calculated, to whether fuel costs may be estimated ahead, and to provisions for retrospective adjustment for so-called under-collections or over-collections. These matters are explored in the following sections where the details of fuel adjustment procedures are considered.

Fuel Price Adjustments

One design for fuel adjustment calculations adjust rates only for changes in the prices of fuels used for electricity generation. Adjustment for fuel price changes is the historical purpose of fuel adjustment procedures, and adjustment procedures based only on fuel prices have long been used in many jurisdictions.

If a utility has only one generating plant, the rate adjustment is based on the change in the average price (in dollars or cents or mills per million Btu) of fuel burned at this plant. But one million Btu's of fuel does not generate exactly one kilowatt-hour of electricity for sale, so the fuel adjustment charge per kilowatt-hour must be different from the fuel price change per million Btu. The appropriate conversion factor is the number of Btu's required to generate sufficient electricity for one kilowatt-hour of sales.

If a utility has more than one source of electricity supply, the change in fuel price may not be the same for all of the different sources. It is therefore necessary to have a formula for calculating the average change in fuel prices, and the impact of this average change on the fuel cost per kilowatt-hour. The most appropriate way to make this calculation is to determine what the average fuel price and fuel cost per kilowatt-hour would have been in the current period, if the utility used exactly the same quantities of fuel that it did use in the test period that serves as the basis to which the fuel price adjustment is applied. This calculation isolates and separates this effect from changes in the generation mix or in the heat rates.

If fuel prices are moving in the same direction as the total cost of electric utilities, then interim fuel adjustments will help keep rate levels in line with total cost. This is the one advantage of routine interim fuel adjustment procedures, but even it is suspect, as shown by the experiences of much of the 1950's and 1960's, when fuel prices were going up as total cost went down. There is much stronger argument for the use of interim fuel price adjustments in periods such as 1974 and 1975, when fuel prices are moving upward (or downward) with extreme rapidity. In these circumstances, it is highly likely that changes in fuel prices will dominate the total changes in electric utility cost, and interim fuel adjustments are therefore likely to keep rates in line with total costs.

The principal disadvantage of interim fuel price adjustments is that they may reduce the incentives for a utility to minimize the prices that it pays for fuel (and for purchased power, if the price of purchased power is also entered into the calculation of the adjustment). When markets for fuel are unsettled, it can be argued that there is considerable scope for aggressive action by utilities to seek lower priced fuel supplies. But if interim fuel price adjustments permit utilities to pass on fuel price increases to ratepayers, and also require utilities to pass on any fuel price savings, then the incentives for management aggressiveness in this regard are reduced. For example, many electric utilities agreed in 1974 and 1975 to renegotiation of their long-term contracts for coal and oil, thus allowing fuel prices to increase.[6/] Since it is extremely difficult for a regulatory authority to investigate in detail the circumstances of each such renegotiation, to determine whether in fact the electric utility had no practical option but to accept the fuel prices higher than those specified in its existing contract, the need for financial incentives affecting the utility is emphasized. If fuel adjustment clauses did not allow the utilities to pass on the higher fuel prices to the ratepayers promptly (or not at all until the next rate case), then perhaps they might have behaved differently in dealing with the fuel suppliers.

A second possible disadvantage of the fuel price adjustment procedure is that it may permit price adjustments based on quantities of fuel that have not in fact been burned. This is particularly so if the adjustment is calculated from the

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[6/] Environmental Action Foundation, "A Citizen Guide to the Fuel Adjustment Clauses," pp. 16-17, has several examples.

fuel quantities burned in the base period, rather than those burned in the current month. For example, if a utility uses less coal in the current month than in the base period, and if the price of coal has gone up, an adjustment which is calculated for the larger quantity burned in the base period, not the smaller quantity burned in the current period, will produce excess revenues. It can, of course, be argued that failure to adjust for changes in the generation mix is necessary to preserve the incentive for minimizing the cost of producing electricity, but such an approach is seen by some as a "rip-off". In any event, it should be noted that this effect works both ways: if the utility burns more coal in the current month than in the base period and the cost adjustment is still calculated from the base-period quantity, the result will be undercompensation rather than an overcharge.

A final point about the fuel price adjustment procedure relates to what this procedure does not do, and to the potentially favorable effect of this omission on incentives for minimizing the cost of electricity supply. When rate adjustments are made only for changes in fuel prices, the amount of the adjustment does not depend upon the actual generation mix used in the current month. If there are major changes in the generation mix, the average cost of fuel burned per kilowatt-hour of energy sales may change substantially. If the utility succeeds in obtaining more of its power from sources with low fuel costs, then its total fuel bill will go down; whereas the total fuel costs will go up if the generation mix shifts towards increased use of power supply sources with high fuel cost per kilowatt-hour. But in either event, these changes in the total fuel expense are not reflected in rate adjustments calculated according to the fuel price adjustment procedure, because these cost changes are due to changes in the generation mix, not to changes in fuel prices.

The advantage of not letting the fuel cost adjustment reflect changes in the generation mix is that the incentives for minimizing total short-run operating costs are preserved with the same strength that they have when there is no fuel adjustment at all. Since the adjustment to the utility's rates depends only upon the prices that it pays for fuel, but not upon the quantities that it uses, there is no financial incentive for the utility to treat fuel usage decisions differently than it would if there were no fuel adjustment at all. The rates are not increased on account of increased fuel expenditures due to increased fuel use, nor are they reduced on account of decreased expenditures due to decreased fuel use; and therefore the utility gains no financial advantage by substituting fuel outlays for outlays on other inputs to the production of electricity. This comment also applies to decisions that affect fuel usage through changes in heat rates, because these changes too are not reflected in rate adjustments pursuant to the fuel price adjustment process.

Adjustment for Changes in the Generation Mix

A key characteristic of a fuel price adjustment procedure is that rate changes do not reflect the effect of changes in the generation mix on average fuel expenditures per kilowatt-hour. This characteristic has both its advantages and its disadvantages, as noted briefly in the preceding discussion on the fuel price adjustment procedure. To explore these advantages and disadvantages more fully, it is helpful to consider a fuel adjustment procedure in which rate changes are made to correspond to the impact of both changes in fuel prices and changes in the generation mix on total fuel cost per kilowatt-hour of sales, but in which no rate adjustment is made for changes in heat rates or in the loss factor. The reason for reviewing this fuel adjustment procedure intermediate between the pure fuel price adjustment and the comprehensive fuel cost adjustment to be discussed in the following part of this section is to isolate the effect of adjusting the rate level for changes in the generation mix from the further adjustments corresponding to heat rate changes and changes in the loss factor.

The adjustment for changes in both fuel prices and the generation mix reflects the impact of fuel price changes in essentially the same way that the pure fuel price adjustment procedure reflects these fuel price changes. The one difference is that there are no rate level adjustments for changes in the prices of fuel not actually burned. The reason is that the amount of the rate adjustment is calculated on the basis of the current generation mix rather than the base period mix. Therefore, if less of an expensive fuel is used in the current period than in the base period, the rate adjustment will reflect the impact of higher prices for that fuel only on the smaller amount actually burned, rather than in relation to the larger amount burned in the base period, as under the pure fuel price adjustment procedure.

Since changes in the generation mix may be the cause of the greatest amount of change in total fuel costs per kilowatt-hour, especially when fuel prices are relatively stable, rate level adjustments that reflect the impact of these changes are likely to be much more closely coordinated with changes in average fuel costs per kilowatt-hour than rate level changes reflecting only adjustments for fuel prices. This matching has a certain philosophical appeal, but closer inspection suggests several important questions about its validity as a principle of public utility regulation.

Fuel costs are only one of several cost components for electric utilities, and the merit of changing utility rates in accord with fuel costs changes is therefore dependent upon other costs remaining more-or-less constant, at least with respect to the factors that cause changes in fuel costs. As a practical matter, however, it is not valid to assume that other cost factors will not change. As stated in the introductory discussion of incentives, there are numerous opportunities for utility management to make substitutions between fuel and other inputs to the production of electricity. Changes in the quantity and therefore the expenditure on fuel may be inversely related to changes in the use of other productive resources, and it is bad regulatory policy to reflect the change in fuel expenditure in the the rate level without also reflecting the offsetting changes in expenditure on other inputs. In addition to the important equity considerations of this policy, its effects on incentives may be strongly adverse. The utility has no financial incentive to economize on its use of fuel, if these fuel savings depend upon the expenditure of other resources, because the the cost of additional fuel can be passed on immediately to the ratepayers, whereas the costs of other resources cannot.

Consider several examples of the reasons why changes in the generation mix occur. First, suppose that these changes are due to changes in the availability of the various plants that a utility can use for generating electricity. If the change in availability is due to scheduled maintenance, or to the normal seasonal variation in hydrologic conditions, it is incorrect to reflect this change in plant availability in rates if, as is usually the case, these normal and expected variations in availability are (as usual) already taken into account in computing the base rates. If the change in generation mix is due to the addition or retirement of generating units, then it is also incorrect for the rates to reflect fuel cost differences due to this change in generation mix. Addition of a large new nuclear generating facility will reduce the average fuel cost of power production, because the fuel cost component of nuclear generation is much lower than the fuel cost of fossil-fuel generation. However, it does not follow that the total cost of nuclear generation is less than the total cost of fossil-fuel power, and it is therefore an incorrect presumption to assume that rates should be lowered simply because more nuclear generation is available. If there have been major changes in the utility's plant structure, there may have been major changes in all of the components of the utility's costs. Rate changes should therefore be based upon a full rate investigation, including analysis of the rate base, and not merely on changes in the fuel component of total costs per kilowatt-hour.

Another possible cause for changes in the generation mix is unscheduled plant outages. If these outages are completely beyond the control of the utility's management, and if they have a substantial effect on the utility's fuel cost, then it is perhaps appropriate that the cost effects be passed on to the ratepayers. However, it is unlikely that plant outages are completely beyond management control.[7/] In the competitive sectors of the American economy, each business bears the costs

[7/] For example, in the case of Alabama Power, the prolonged outage (1975-present) of the Bouldin Dam Hydroelectric generation unit may be at least partially attributable to the Company's actions prior to and subsequent to the breech.

of its own operational failures and difficulties because it cannot include in its prices the costs of production problems more severe than those experienced by its competitors. There is always a risk of encountering such difficulties and that is one of the reasons why common equity costs and returns exceed risk-free capital costs. This discipline of competition is one of the most important goads to productive efficiency, and there is no reason why it should not also be applied to public utilities to the maximum extent possible. If changes in the generation mix are <u>not</u> reflected in the rates, then a utility with unusually severe operational problems must bear the costs of these problems, at least until the next rate case, when it can attempt to convince its regulatory commission that these operational difficulties are a proper part of its cost and therefore its rate level. Conversely, a utility with an unusually good operating record will be able to earn greater profits than one whose track record is less satisfactory. These arrangements are the best incentives for good operational performance. Their disadvantage is that they may cause financial difficulties for a utility experiencing unusual problems, and they deny to consumers the savings that result from unusually high operating efficiencies. If that happens too frequently, and too severely, it will be to the ratepayers advantage if economic circumstances create pressures for corporate reorganization or at least encourage stockholders to insist upon a change in corporate management. Any regulatory process which automatically bails management out of financial difficulty will remove the economic impetus for change that is so essential for efficiency in a free enterprise economy.

In general, it can be a strong incentive for cost minization if the rates of a utility are fixed in a manner that does not automatically track all costs actually incurred by the utility. Such an approach would permit the shareholders to obtain some benefit from any cost savings that can be achieved through improved productivity and efficiency, and it forces them to bear some of the consequences of corporate cost control failures. At the same time, this approach would protect ratepayers from the cost consequences of managerial failure. Since the ratepayers derive no benefit from cost savings until they are eventually reflected in lower rates, and since an electric utility may be unable to continue to provide adequate service if it is not eventually compensated for its actual costs, periodic rate adjustments in general rate cases should eventually reflect newly attained cost levels and encourage further efficiency. One of the most important areas for informed judgment by regulatory authorities is in achieving an appropriate balance between performance incentives, which are strongest with fixed rates, and the reflection of performance results through changes in the rate level. Additional comments on this problem appear below.

Comprehensive Fuel Cost Adjustment Procedures

When a comprehensive fuel and purchased power cost adjustment procedure is used, the rate level is adjusted to reflect the actual total cost of fuel and purchased power per kilowatt-hour of electricity sold. This arrangement insures that an earmarked part of total revenues will exactly equal total fuel and purchased power costs. This, however, is no guarantee that the total revenues, including the base rates not subjected to interim adjsutment, will correspond exactly with total cost of service. Rates subjected to comprehensive fuel purchased power cost adjustments will move in accord with the total cost of service if and only if the changes in fuel costs--including those resulting from changes in fuel prices and the generation mix--are the dominant factor in total cost changes. The historical record of the electric utility industry certainly does not support this proposition.

The key disadvantage of a comprehensive fuel and purchased power cost adjustment procedure is that it both weakens and distorts the incentives for cost minimization. With this type of fuel adjustment procedure in effect, a utility has no financial incentive to economize on the use of fuel, when to do so would require the expenditure of money on any other resource. The reason is the obvious one that fuel costs can be recovered immediately and in full; whereas variations in expenditure on other costs cannot be recovered at all, except to the extent that they occur within a period that becomes the test year for a future general rate investigation.

This analysis comes down quite hard against the use of comprehensive fuel and purchased power cost adjustment procedures. The question may therefore arise as to why procedures of this type have gained the popularity that they now have. Two answers can be given. First, a comprehensive fuel and purchased power adjustment clause is somewhat less subject to abuse than a pure fuel price adjustment procedure. The comprehensive fuel and purchased power cost adjustment can be defined by a relatively simple set of regulations, such as those adopted by the FERC in its Order No. 517, and the implementation can be left largely to the regulated utility. In contrast, the proper specification of a pure fuel price adjustment procedure is somewhat more complex, and general regulations defining this procedure have not been adopted in any jurisdiction. Second, many commissions, including the FERC, have been much more concerned with accuracy in tracking actual fuel costs than with the problem of incentives. This attitude may be due in part to the view that imperfect tracking is _ipso factor_ an abuse, but whatever the reason, it is strongly held by many regulatory bodies.

Abuses in the Design of Fuel Adjustment Procedures

Much of the opposition to interim fuel adjustment procedures results from the past misuse or abuse of these procedures, rather than from objection to the inherent characteristics of properly designed fuel adjustment procedures. It would be wrong to condemn all fuel adjustment procedures in principle, merely because abuses have occurred at some time and in some jurisdictions. On the other hand, if the danger of abuse is greater with interim fuel adjustment procedures than with other kinds of regulatory response to changes in costs, then that argument should be given some weight. In the judgment of the authors of this report, properly designed interim fuel adjustment procedures can be less subject to abuse than other means for reducing regulatory lag, such as the use of a future test year. However, this is a matter that each regulatory authority must decide for itself.

To aid in understanding and avoiding the common pitfalls of interim fuel adjustment procedures, the following paragraphs present information about some of the most frequently cited abuses of fuel adjustment procedures.

1. Use of fuel adjustments only when fuel prices are rising.--The first abuse of interim fuel adjustment procedures is their use only in times when fuel prices or fuel costs are rising, and their cancellation when fuel costs and prices are falling. It has happened, at least for some companies in some jurisdictions,[8/] and it is understandable why customers and consumer groups are upset about it.

[8/] Citizen's Guide, *supra*, p. 3.

2. Adjustments for phantom fuel.--A second abuse of fuel adjustment procedures is to calculate the amount of the adjustment on the assumption that all electricity is generated in fossil-fuel plants, even when this is not so (because there is substantial nuclear or hydroelectric generation). This error is found most frequently in a fuel adjustment procedure relating only to changes in fuel prices, and it commonly results in an adjustment factor that is too high. If the adjustment factor allows the utility to increase the price of each of its kilowatt-hours of sales as though that kilowatt-hour were generated entirely from fossil fuels, despite the fact that a substantial fraction of the total energy is obtained from other generation sources, then obviously the fuel adjustment will create excess revenues at times when fossil fuel prices are rising. On the other hand, this same provision will penalize a utility when fossil fuel prices are falling, but this has not happened since nuclear generation has become a major factor in the electric utility industry.

The problem of phantom fuel should be distinguished from the use of a fuel adjustment procedure based upon a fixed generation mix. If the generation mix changes between the base period for the fuel adjustment calculation and the current period, then, as noted in the description of this type of fuel adjustment calculation, the adjustment amount will be based in part upon fuel quantities not actually burned. However, changes in the generation mix between one complete rate investigation and the next are likely to involve operational activities and not merely changes in the composition of the generating plant. In these circumstances, the use of a fixed base-period generation mix between general rate investigations can be an appropriate incentive. It is only when the generation mix used to derive the fuel price adjustment factor remains unchanged for many years, and fails completely to keep up with changes in the structure of the utility's generating operations, that the abuse of phantom fuel is likely to be a serious problem.

A similar problem may arise with the heat rates used to derive the fuel adjustment factor. Since there has been a secular trend to improvements in heat rates, the use of a far out-of-date rate leads to a fuel adjustment factor that is too high. But again, there is some offsetting desirable incentive value of retaining a fixed heat rate for interim adjustments from one general rate investigation to the next, revising the heat rate downward (if appropriate) only when the fuel adjustment factor is recalculated in the next general rate investigation.

3. <u>Manipulation of fuel prices, especially in dealings with subsidiaries</u>.--Many electric utilities own fuel subsidiaries, including coal mining companies and, especially more recently, subsidiaries engaged in the search for and purchase of petroleum fuels. The prices paid by electric utilities for fuel purchased from their own subsidiaries or affiliates

have long been a serious regulatory problem. This problem is not primarily related to interim fuel adjustment procedures, because concern over the fairness and reasonableness of fuel prices is as much applicable to the base-period fuel costs identified in a general rate investigation as it is to the claim for interim rate adjustments reflecting fuel price increases since the last complete rate investigation. This having been said, it is also worth noting that the existence of an interim fuel adjustment procedure may provide the excuse for ignoring fuel costs in a general rate investigation; while the interim procedure itself may not afford the regulatory authority sufficient opportunity to make an in-depth study of the relationship between the utility and its affiliated fuel supplier, or of the relationship among the prices paid to the affiliate, the affiliate's costs, and the fuel market in general.

4. Estimated fuel adjustments.--Another opportunity for abuse of fuel adjustment procedures is the use of estimated fuel prices or fuel quantities. The danger of estimation is that the utility may err consistently on the side of higher rates. One way to correct this problem is to hold over-collections and under-collections in a revolving fund to which interest should also be imputed, and amortize whatever balance may appear in the fund in the calculation of the next period's estimated interim fuel adjustment factor.

Use of An Incentive Factor With Fuel Adjustments

The discussion in the two preceding sections relates to the determination of the way in which fuel costs per kilowatt-hour are changing. This is the second step in the implementation of an interim adjustment procedure; and after it, there remains the translation of the cost change into a rate adjustment. This final step involves the determination of how the cost change is to be recovered in the rate structure, but it also involves the decision about how much of the cost change is to be recovered through an immediate adjustment to the rate level.

The opportunity for choice at this point has not generally been perceived. In the past, where fuel adjustment procedures have been used, the change in the rates has generally been set exactly equal to the total cost change, as calculated by whatever fuel adjustment approach has been adopted. This arrangement is equivalent to making an interim rate adjustment of one hundred percent of the fuel cost change. One alternative, which has been embraced where the abuses and defects of fuel adjustment procedures became a dominant concern, is the complete elimination of interim fuel adjustments. This, of course, is equivalent to rate adjustments of zero percent of the fuel cost change. But zero and one hundred percent are just two extreme points in what should be seen as a continuous range within which regulatory commissions may exercise more rational discretion.

The principal reason for permitting a partial--but not complete--inclusion of the fuel cost change as an interim adjustment to the rate level is that interim fuel adjustments are neither entirely good nor entirely bad. If a utility is required to include only some fraction of its calculated fuel cost change in its rates, then some of the benefits that result from interim fuel cost adjustments are still being realized. At the same time, some of the efficiency incentives that depend upon the fixity of rates are also present, because some of the additional costs or cost savings that result from changes in fuel expenditures are borne by the utility. For this reason, the allowance of a rate level adjustment equal only to a percentage of the calculated change in fuel costs is here called an incentive factor.

The argument given to this point does not prove conclusively that the use of an incentive factor is desirable. It may be that incentive considerations outweigh the arguments in favor of any fuel adjustments, and that no fuel adjustment is therefore the proper regulatory policy. This is an important area for the exercise of regulatory judgment, and it is not the purpose of this report to reach a single conclusion on the merits of fuel adjustment clauses. However, it is possible to argue strongly against a 100 percent pass-through of the calculated fuel cost change and in favor of the application of some incentive factor in whatever fuel adjustment clauses may be adopted.

The argument for an incentive factor is based primarily on the proposition that public utility regulation has been and seems likely to remain an art, rather than an exact science. Public utilities are far too complex for regulatory agencies to maintain rates at levels exactly equal to what costs currently are, and it is even more difficult for regulatory agencies to ensure that costs are continuously what they should be. Since rates can only be established within a zone of reasonableness, it is spurious to argue that monthly rate changes must be made exactly equal to monthly changes in fuel costs. An incentive factor of, say, ninety percent will provide essentially all of the benefits of a fuel adjustment procedure, namely extension of the time during which the divergence between rates and costs is kept within a zone of reasonableness, and it will add an important incentive element to the rate design. Stronger incentives (i.e., lower percentage factors) may also be desirable; but once there is at least a significant incentive factor, it remains for the judgment of the regulatory agency to determine whether the benefits of stronger incentives are or are not outweighed by the possibility that revenues will fail to keep pace with costs in a time of unsettled fuel prices.

The need for a strong incentive factor is greater with a comprehensive fuel and purchased power cost adjustment procedure than it is with an adjustment procedure based only upon fuel price changes. The reason is that the fuel price adjustment procedure preserves most of the incentives for efficient management of fuel and other resources in the short run, whereas comprehensive fuel cost adjustment procedures do not. Both approaches dilute the incentive for the utility to obtain the best possible prices for its fuel, but this aspect of public utility management is perhaps one where strong incentives are less necessary than in system planning and operational procedures.[9/]

Both types of fuel adjustment approaches also direct the incentives for planning investments to achieve the minimum-cost combination of fuel and capital. However, a utility achieves only a diminution of risks, not an absolute increase in its profits, by building generating plant with lower capital cost but higher fuel use. The reason is that the consequences of these investment decisions are established at the time the plant is built, and the costs--both for fuel and for plant --are reflected in base rates established in complete rate cases. If a utility's investment decisions result in higher fuel costs and lower expenditure for other inputs to the production of electricity, the utility does not need an interim fuel adjustment to recover these higher fuel costs. All that interim fuel adjustments do is protect the utility against the risks of unforeseen increases in fuel costs, thus reducing the risks associated with a fuel-intensive investment policy.

[9/] Fuel price minimization may also be a problem where fuel is purchased from an affiliated company, as explained above. Further possible solutions are discussed below.

Correspondingly, use of generating plant with lower capital costs reduces the risks associated with regulatory lag in regard to determination of base rates; but, as has been shown, this also reduces the benefits that utilities reap when regulatory lag works in their favor. In sum, investment decisions are probably the area in which it is most crucial that there be appropriate incentives for utility managements, but it is somewhat less certain that interim fuel adjustment procedures are an important and an adverse factor here, though the empirical record of investment decisions over the last decade is not inconsistent with a concern about the possible adverse effects of fuel adjustment clauses on capacity expansion decisions.

One of the ways that regulatory commissions have found (perhaps accidentially) to introduce incentives into fuel adjustment procedures is to ignore some of the costs actually associated with fuel. In some jurisdictions, fuel cost changes are calculated in relation to total kilowatt-hours generated, not in relation to kilowatt-hour sales. This forces the utility to absorb, at least until the next complete rate case, the fuel cost changes applicable to that fractional portion of its total net generation that is lost in transmission and distribution rather than sold. This arrangement is thus an incentive factor equal to the percentage of energy losses experienced by the utility. Another similar omission is that related to gross receipts taxes, which are imposed in many jurisdictions.

If the rate adjustment is not marked up to permit recovery of the gross receipts tax (where one exists) on the additional fuel adjustment revenue, then that percentage of the rate adjustment goes to the tax collector rather than to the utility; and this amounts to an incentive factor. On the assumption that utility managements understand their business and their rates thoroughly, these incentives are no less real even as omissions from the regulatory decision process than are explicitly intended incentive factors.

Special Considerations Involved in Fuel Adjustment Procedures

This section presents a discussion of three common special considerations that arise in the use of interim fuel adjustment procedures. These considerations are the treatment of purchased power; seasonal fluctuations in fuel costs; and the uncertain availability of low-cost energy.

1. Purchased power--Virtually all electric utilities now engage in the purchase and sale of electric power. Three major types of purchased power transactions can be identified: unit purchases; firm power purchases; and energy service. These three types of transactions are discussed in turn.

Under a unit purchase arrangement, the purchasing utility acquires the use of part (or all) of a specific generating unit, and it becomes responsible for its proportionate share of the operation and maintenance costs of that unit during the term of the purchase. For purposes of fuel adjustment proceedings, the simplest way to deal with unit purchases is for the purchaser to report its share of the generation and fuel costs of the purchased unit as though it were its own. The same applies to a share in any jointly-owned generating unit.

Under a firm power purchasing arrangement, the purchasing utility pays both a demand charge and an energy charge. Typically the energy charge includes a fuel adjustment provision of some kind. The simplest and most usual way to incorporate firm power purchases into fuel adjustment procedures is to treat the firm power purchase as though it were a generating unit on the purchasing utility's own system, and to recognize the identifiable fuel cost component of the purchased power price as though it were a fuel expense of the purchasing utility on that unit. This arrangement implicitly accepts the fuel adjustment provisions governing the purchased power transaction as appropriate for reflection in the retail rates, even though the purchased power transaction in most instances is made according to the rules and regulations of a regional power pool subject to FERC jurisdiction. Where the quantities of purchased power are small, it is probably not worthwhile for a state regulatory commission to attempt to recalculate the firm power fuel adjustment, to reflect principles that the state commission may prefer, even if they conflict with the fuel adjustment provisions actually governing jurisdictional power sales. Such a passive role may, however, not be appropriate where a jurisdictional utility purchases a large portion of its bulk power supply from another company, or from an affiliate or parent.

In the case of firm power purchased from an affiliated company, it may be particularly appropriate for the state regulatory commission to require that the affiliate submit the fuel cost data that would otherwise be required of the company regulated directly by the state, and it may then be possible for the state commission to pierce the jurisdictional veil and calculate fuel adjustments as though the generation were actually done by the jurisdicational utility.

The third kind of purchased power transaction is the provision of energy service. Energy service may be required at times of scheduled maintenance or unscheduled outage of a generating unit; and exchanges of so-called economy energy are often made through power pools to insure that as much energy as possible is generated from the units with the lowest running costs available to any member of the pool. Where the transaction prices for energy service are based upon actual running cost, which consists almost entirely of fuel, it is appropriate to treat the payments for energy service as though they were fuel costs.

2. Seasonal factors--In some parts of the country, there are seasonal fluctuations in the average fuel cost for electricity generation. These fluctuations are due largely to seasonal fluctuations in the hydrologic conditions affecting the availability of hydroelectric energy. Seasonal differences in the

availability of natural gas, which is less expensive than other fossil fuels, have also been a factor in the past; but the continued availability of large quantities of natural gas for electric utility boiler fuel is now at best doubtful. In any event, the determination of a proper seasonal structure for electric utility rates, reflecting to the appropriate extent the seasonal variations in both supply and demand conditions, is not a matter conveniently determined through interim fuel adjustments. Instead, such fluctuations for expected seasonal as well as time of day cost variations should be reflected directly in base rates rather than through the fuel adjustment mechanism. Therefore, especially where seasonal or time of day cost variations are reflected in the base rate structure design, some attention is required to insure that the interim adjustment procedure does not impose a further unwanted fluctuation on the rate level.

Several methods may be used to smooth the rate impact of seasonal fluctuations in fuel costs. One is to let each month's adjustment charge in the rates be the average of the previous six months' fuel cost factors. Six months is chosen as the shortest span likely to cover a period of both high and low fuel costs. This lag in rate adjustments behind fuel cost changes also has a beneficial effect on incentives, because partially delayed recovery of fuel cost increases is not as attractive to the company as immediate recovery. However, delay is not nearly as strong an incentive as exclusion of a part of the fuel cost adjustment from ever being recovered (until base rates are reviewed in a full rate case), as is here proposed.

A second method for smoothing seasonal fluctuations is to base fuel adjustments on fuel prices only with a fixed generation mix. Since the seasonal fluctuations are caused by seasonal changes in generation mix, use of a fixed base-period mix will eliminate these fluctuations. On the other hand, this smoothing technique applies only to some design variants of the fuel adjustment clause; and where there are large and predictable fluctuations in the generation mix, this fuel clause design variant is subject to abuse through management impact on the scheduling of fuel use and its effect on fuel prices.

The third way to smooth seasonal fluctuations in fuel adjustment charges is to use different fuel cost bases for the different months of the year. If the adjustment depends only upon fuel prices, with a fixed base-period generation mix, this mix can be different for the different months of the year, reflecting each month's normal hydrologic conditions. If the adjustment is for the average fuel cost per kilowatt-hour sold, reflecting fuel cost changes from all sources, then the base cost amount can be taken from the corresponding calendar month of the base year, instead of from the annual average for the base year. In either case, the monthly adjustment charge will not be influenced by the normal seasonal variations in the generation mix or in the associated fuel cost.

3. <u>Uncertain availability of low-cost generation</u>--In some areas, the amount of water available for hydroelectric generation varies widely from year to year. Where hydro is a large fraction of the total generation of electricity, the variations in hydroelectric output have a substantial impact upon the average fuel cost per kilowatt-hour of electricity generated. Under these circumstances there can be special fuel cost problems.

For example, in the past, it had been the policy of the California Public Utilities Commission to establish rates based upon "normal" hydrologic conditions, and to have the utility company shareholders (rather than the ratepayers) absorb the financial consequences of water flows above or below normal level. The large increase in fuel prices in 1974 and 1975 has magnified greatly the dollar impact of variations in hydrologic conditions, because it greatly increases the value of fuel savings in good water years or of additional fuel requirements in bad years. The impact of hydrologic variations upon the financial situation of the California utilities was dramatized by record water conditions in the first two years of much higher fuel prices, with the result that the utilities reaped savings of hundreds of millions of dollars. Where changes in the generation mix can have so great a financial impact, it may well be desirable to introduce an interim fuel adjustment procedure solely for the purpose of reflecting these cost changes in the rates, even if no other fuel adjustment is necessary. An interim fuel adjustment amount should be calculated to reflect the effect of changing hydrologic conditions upon fuel costs, as well as other fuel cost factors that the regulatory commission may choose to incorporate in the adjustment procedure.

It must be noted in this connection that the effect of changing hydrologic conditions relates to the saving or increased expenditures on fuel at the base fuel price, not merely to the amounts by which fuel prices have changed since the last complete rate investigation. This point escaped notice in several analyses of the California situation, because the bulk of the fuel cost was being recovered through fuel clauses rather than in the base rates, owing to the then recent and extremely rapid increases in fuel prices, which had not yet been reflected in the base rates. But the collection by the utilities of phantom fuel costs in good water years would be just as great if the fuel costs were in the base rates as if they were recovered in a fuel adjustment, though they might be less visible in the base rates. Fuel adjustment procedures should therefore be viewed as a solution to the problem of uncertain availability of low-cost hydroelectric generation, not as part of the cause of that problem.

III. The Alabama Power Company Energy Adjustment Factor

Alabama Power Company's Energy Adjustment Factor (EAF) appears in the Company's tariff as Rate FT, and includes a monthly adjustment for both energy costs and changes in taxes. The energy cost portion of the charge consists of two parts. The first part is an adjustment based upon estimated energy costs for the current billing month and the fuel costs included in the base rates, expressed as mills per Kwh sold. The second part is a clearing provision which adjusts for differences between previous estimates and actual costs. The general form of the calculation procedure is shown in Table 1.

Rate FT was initially approved by the Alabama Public Service Commission on July 20, 1964, in Informal Docket U-2090, and replaced the Company's first fuel adjustment, Rate Schedule IL (applying only to large industrial customers) which was approved by the Commission in 1953. Rate FT applied to all[10/] retail customers, and first appeared on customer bills in November of 1969. The present form of Rate FT is the result of several revisions and is dated April 28, 1977. The Commission has been conducting an investigation of the energy adjustment clause in Docket 17107 since December of 1975.

[10/] With the exception of several large contract customers. The exceptions are being eliminated as the contracts expire.

The computation procedure shown in Table 1 includes two constant values. The 2.5 mills per Kwh was the energy cost per Kwh generated as of the 1964 creation of Rate FT, and therefore represents a portion of the energy costs in the Company's base rates. The second constant, designated as R and currently set at 9.0 mills, is the additional base energy cost, expressed in mills per Kwh sold, included in the Company's base rates in Docket 17261 (April 1977). The value of R can be changed in subsequent rate proceedings to reflect the level of energy costs rolled into base rates.

The Energy Adjustment Factor is calculated according to estimated energy costs for the current billing month, limited to the Uniform System of Accounts numbers indicated on Table 1. The EAF included costs of fossil fuels, nuclear fuel and net purchased power, expressed in mills per Kwh sold. Estimates of fuel and purchased power costs, estimated generation and estimated sales for 1978 are shown on Table 2. Estimated hydro output is included implicitly in the sales estimate, and reduces the cost of energy.

In addition to the cost estimates shown on Table 2, Alabama Power Company's EAF includes an adjustment factor which is intended to reconcile the estimates with actual costs as they become known. The computation of the adjustment is shown on Table 3. The adjustment portion of the EAF takes the difference between actual energy costs, prorated to the customers subject to the clause, and the cumulative recovery from these customers (including the 9.0 mills in the base rates) on both an actual and estimated basis. The recovery amount is cumulated to account for the estimates used in calculating recoveries for the immediately previous month. The adjustment amounts for each of the months in 1978 are shown in Table 4.

In the monthly fuel reports filed with the Alabama Public Service Commission, the Company provides data useful for evaluating the performance of the clause. For example, cost and generation are broken down by Uniform System of Accounts number and by plant. Sales estimates are provided by customer class. Furthermore, comparative data are provided for fuel cost adjustment amounts provided to wholesale and steam customers. The wholesale-retail energy adjustment charges are shown on Figure 1.

In addition, the Alabama Public Service Commission monitors the EAF through monthly audits and public hearings. The audit staff keeps cost and usage data, including the accumulated balance of the adjustment amount. The records maintained at the Commission and audited by the Commission staff can be used to track cash flows and recovery times, and are a useful source of information for the monthly hearings.

The comprehensive energy cost adjustment clause (Rate FT) applicable to electric power sales by the Alabama Power Company is comparable to fuel adjustment procedures in other jurisdictions. It is apparent that the Alabama clause passes through fuel costs to consumers as intended and that the resulting monthly rate adjustment calculations are checked regularly by the Commission and its staff.[11/] Rate FT is therefore free from several of the more important potential abuses of fuel adjustment clauses discussed above. Revenues appear to track costs accurately over time; subsidiary transactions problems which plagued the past have been substantially removed; and cost savings attributable to improvements in system generation mix are flowed through to consumers wherever they occur.

[11/] The procedures followed in Alabama with respect to energy cost adjustment Rate FT appear to be in full compliance with new federal standards applicable to automatic adjustment clauses as specified in Section 115 of the Public Utility Regulatory Policies Act of 1978 which states: (1) an automatic adjustment clause of an electric utility meets the requirements of this sub-section if--(A) such clause is determined, not less often than every four years, by the state regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and (B) such clause is reviewed not less often than every two years, in the manner described in paragraph (2), by the state regulatory authority having ratemaking authority with respect to such utility (or by the electric utility in the case of a nonregulated electric utility), to ensure the maximum economies in those operations and purchases which affect the rates to which such clause applies.

(2) In making a review under sub-paragraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause, and shall require such reports as may be necessary to carry out such review (including a disclosure of any ownership or corporate relationship between such electric utility and the seller to such utility of fuel, electric energy, or other items).

Possibilities for improving the Alabama Fuel Adjustment Clause therefore pertain largely to fundamental questions of regulatory policy rather than to changes in technical implementation. Indeed, there are only two purely technical matters of significance and both are relatively minor. First, it would be possible to simplify the adjustment formula somewhat by combining the 9.0 mill and 2.5 mill offsets so as to make the computation appear less cumbersome and more intuitively comprehensible. This is essentially a matter of cosmetics, but it is certainly not irrelevant insofar as consumer displeasure with utility rate increases tends to accelerate when the basis for such increases is too confusing to be easily understood. Second, it would be possible to track costs somewhat more accurately by including an element in the clause to reflect the fact that fuel costs per kilowatt-hour vary by delivery voltage level. That is, since it takes fewer Btu's at the generation level to deliver a kilowatt-hour of energy at high voltages where line losses are less, it would be appropriate for the energy cost adjustment factor to vary by delivery voltage. Similarly, as time-of-use rates are implemented, it will also be appropriate for the adjustment factor to be higher for peak period consumption than for off-peak deliveries.

Turning to the more important areas of regulatory policy where fundamental conceptual modifications to rate FT may be appropriate, it is clearly a matter of regulatory judgment as to whether (and to what extent) a fuel adjustment clause should be designed to promote and encourage efficiency and productivity improvements as opposed to merely passing through cost changes to consumers. The Alabama Energy Cost Adjustment Clause passes through costs, and that is all; there is no provision for efficiency incentives. For the reasons discussed in detail above, the authors of this report do not believe that such an approach constitutes an optimal regulatory strategy. If the Alabama Commission were to determine that efficiency incentives are an appropriate ingredient in the energy cost adjustment process, that could be easily accommodated by simple modifications to Rate FT. For example, the energy adjustment factor could be computed to pass through, say, only 90 percent of any monthly cost change rather than the full amount. This would not only create the now absent stimulus to hold purchased fuel cost increases down, it would also add an incentive to more efficient system planning and generation mix improvements that would benefit both stockholders and ratepayers.

Another potential area for improvement concerns the lagged adjustment for over- or under-collections. This adjustment takes place because collections are based on prospective cost estimates. At a minimum, the Commission may wish to consider the incorporation of an interest charge for any over-collections so as to discourage any tendency to systematically overestimate costs in the knowledge that over-collections will, in effect, constitute an interest free loan. An appropriate

interest charge on over-collections would be equitable and it might also serve to restrain inflationary biases in cost forecasts which can otherwise become self-fulfilling prophesies.
A second possibility would be to lag the energy cost adjustment until actual costs are known. That would both simplify the computation and at the same time provide a further incentive for cost control. In summary, the Alabama Energy Cost Adjust-Clause is an effective cost pass-through mechanism. Possible modifications to the present approach depend more on the objectives of regulatory policy than on any need for improved technical implementation. The changes suggested here are therefore matters of discretion and judgment and should be considered within the overall context of Alabama's regulatory objectives.

Table 1

Energy Cost Adjustment
Calculation Procedure

The energy adjustment factor to be applied to each kilowatt-hour sold by the Company subject to Rate FT shall be calculated in accordance with the following formula:

$$EAF = \left[\frac{(EFC + ENC + EPPC) - 2.5\ (EFG + ENG + EPP)}{ETS}\right] - R \pm ADJ$$

WHERE:

EAF = Energy adjustment factor to be applied to the retail kilowatt-hour sales to which this Rate FT is applicable during the current billing month and computed to the nearest one-thousandth of a mill per kilowatt-hour.

EFC = Estimated cost of fossil fuel to be recorded in Accounts 501, 518 and 547 of the Uniform System of Accounts prescribed by the Alabama Public Service Commission for the current billing month at the Company's generating plants, including also the Company's portion of estimated fossil fuel cost at generating plants whose capacity is shared with others and the Company's portion of such cost at plants owned or operated by any affiliated company.

ENC = Estimated cost of nuclear fuel to be recorded in Account 518 of the Uniform System of Accounts prescribed by the Alabama Public Service Commission for the current billing month at the Company's generating plants, including also the Company's portion of estimated nuclear fuel cost at generating plants whose capacity is shared with others and the Company's portion of such cost at plants owned or operated by any affiliated company.

EPPC = Estimated net purchased power energy cost to be recorded in Account 555 of the Uniform System of Accounts prescribed by the Alabama Public Service Commission for the current billing month (excluding the cost related to the generation at plants owned or operated by any affiliated company included in EFC and ENC) which remains after deducting capacity or demand charges included therein.

EFG = Estimated fossil generation in megawatt-hours for the current billing month at the Company's generating plants, including the Company's portion of generating plants whose capacity is shared with others and its portion of such generation at plants owned or operated by any affiliated company, corresponding to the cost included in EFC.

ENG = Estimated nuclear generation in megawatt-hours for the current billing month at the Company's generating plants, including the Company's portion of generating plants whose capacity is shared with others and its portion of such generation at plants owned or operated by any affiliated company, corresponding to the cost included in ENC.

EPP = Estimated net purchased power energy in megawatt-hours to be received or delivered for the current billing month, corresponding to the cost included in EPPC.

ETS = Estimated total energy sales by the Company in kilowatt-hours for the current billing month.

2.5 = 2.5 mills per kilowatt-hour.

R = 9.0 mills per kilowatt-hour.

ADJ = The adjustment necessary to compensate for the difference between estimated and actual costs of fossil fuel, nuclear fuel, and net purchased power energy in prior months. Such adjustment represents the accumulated summation of the actual excess or deficient fossil fuel, nuclear fuel, and net purchased power energy costs from the date of implementation of this energy adjustment factor through the second month preceding the current billing month, less the accumulated summation of the actual fossil fuel, nuclear fuel, and net purchased power energy costs recovered through operation of this energy adjustment factor for the same time period, adjusted for the estimated excess or deficient fossil fuel, nuclear fuel, and net purchased power energy costs to be recovered by this adjustment during the first month preceding the current billing month, divided by the estimated kilowatt-hour energy sales to consumers subject to the energy adjustment factor for the current billing month.

TABLE 2

Month	Energy Costs ($000)	Estimated Generation (Mwh)	Estimated Sales (Mwh)	Cost/Kwh Sales (Mills)
January	$31,349	2,537,670	2,702,660	11.60
February	25,838	2,067,100	2,525,000	10.23
March	26,647	2,098,800	2,407,600	11.07
April	25,417	2,171,870	2,395,650	10.61
May	33,831	2,620,640	2,411,020	14.03
June	41,444	3,039,800	2,665,660	15.55
July	46,359	3,221,800	2,934,490	15.80
August	46,135	3,270,080	3,123,250	14.77
September	40,514	2,767,830	2,942,830	13.77
October	28,543	2,406,540	2,609,940	10.94
November	29,234	2,313,060	2,372,620	12.32
December	31,800	2,545,100	2,400,900	13.25

Source: Alabama Power Company, Monthly Fuel Reports filed with the Alabama Public Service Commission.

Table 3

Calculation of the Adjustment Portion of the EAF

$$ADJ = \frac{\sum\left[(AFC_{sp} + ANC_{sp} + APPC_{sp}) - 2.5\,(AFG_{sp} + ANG_{sp} + APP_{sp})\right] P_R - \sum\left[(ATS_R)\,R + AR\right] \pm \left[ADJ_p\,(ETS_R)_p\right]}{ETS_R}$$

WHERE:

AFC_{sp} = Actual fossil fuel cost recorded in Accounts 501, 518, and 547 during the second month preceding the current billing month at the Company's generating plants, including the Company's portion of fossil fuel cost at generating plants whose capacity is shared with others and its portion of such cost at generating plants owned or operated by any affiliated company.

ANC_{sp} = Actual nuclear fuel cost recorded in Account 518 during the second month preceding the current billing month at the Company's generating plants, including the Company's portion of nuclear fuel cost at generating plants whose capacity is shared with others and its portion of such cost at generating plants owned or operated by any affiliated company.

$APPC_{sp}$ = Actual net purchased power energy cost recorded in Account 555 during the second month preceding the current billing month (excluding the cost related to the generation at generating plants owned or operated by any affiliated company included in AFC_{sp} and ANC_{sp}) which remains after deducting capacity or demand charges included therein.

AFG_{sp} = Actual fossil generation in megawatt-hours during the second month preceding the current billing month at the Company's generating plants, including the Company's portion of generating plants whose capacity is shared with others and its portion of such generation at generating plants owned or operated by any affiliated company, corresponding to the cost included in AFC_{sp}.

ANG_{sp} = Actual nuclear generation in megawatt-hours during the second month preceding the current billing month at the Company's generating plants, including the Company's portion of generating plants whose capacity is shared with others and its portion of such generation at generating plants owned or operated by any affiliated company, corresponding to the cost included in ANC_{sp}.

APP_{sp} = Actual net purchased power energy in megawatt-hours received or delivered during the second month preceding the current billing month, corresponding to the cost included in $APPC_{sp}$.

P_R = Ratio of retail sales in kilowatt-hours subject to this energy adjustment factor to total sales in kilowatt-hours during the second month preceding the current billing month.

ATS_R = Actual total sales in megawatt hours subject to this rate FT during the second month preceding the current billing month.

AR = Actual recovery of fossil fuel, nuclear fuel, and net purchased power energy costs through operation of the energy adjustment factor during the second month preceding the current billing month.

ADJ_p = Estimated excess or deficient fossil fuel, nuclear fuel, and net purchased power energy costs to be recovered for the first month preceding the current billing month in mills per kilowatt-hour.

$(ETS_R)_p$ = Estimated total sales in megawatt-hours to retail consumers subject to the energy adjustment factor for the first month preceding the current billing month.

ETS_R = Estimated total sales in kilowatt-hours to retail consumers subject to this energy adjustment factor during the current billing month.

$\sum$ = Represents the accumulated summation of the respective formula components from the date of implementation of the energy adjustment factor through the second month preceding the current billing month.

Figure 1

Fuel Adjustment Clauses Billed
in 1978: Wholesale and Retail Customers

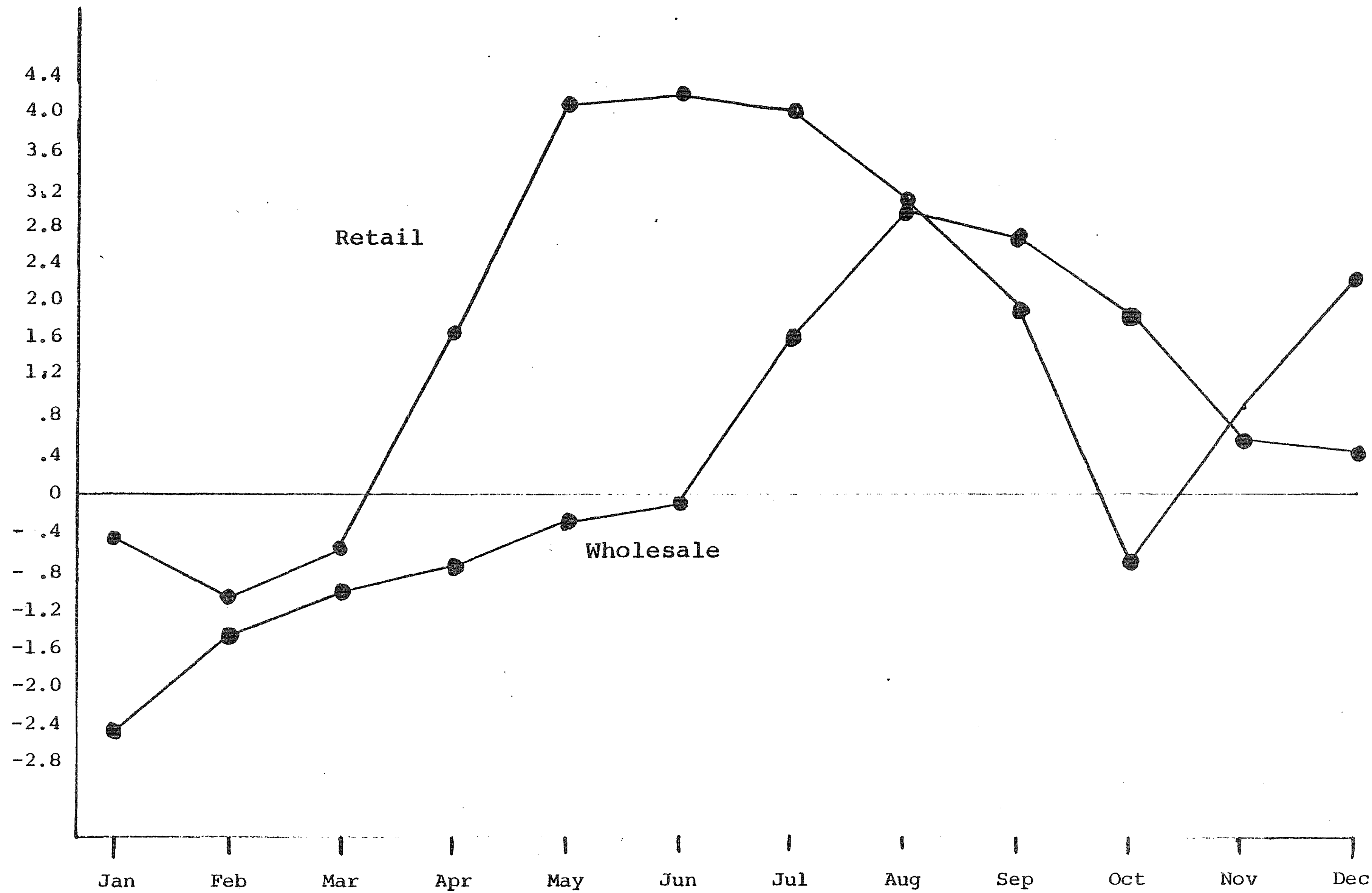

TABLE 4

Alabama Power Company's
Energy Adjustment Factor: 1978
(Mills per Kwh)

Month	Energy Cost Less Base Rate Amount	Adjustment to Actual	EAF Billed
Janaury	.252	- .680	- .428
February	- .814	- .994	-1.808
March	- .112	- .451	- .563
April	- .063	1.733	1.670
May	2.314	1.789	4.103
June	3.696	.546	4.242
July	4.053	.088	4.141
August	3.154	- .042	3.112
September	2.415	- .446	1.969
October	.885	-1.555	- .670
November	.884	.012	.896
December	1.595	.686	2.281

Source: Alabama Power Monthly Fuel Reports filed with the Alabama Public Service Commission.