- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application) of MOUNTAIN FUEL SUPPLY COMPANY for) an Increase in Rates and Charges.)	DOCKET NO. 93-057-01 REPORT AND ORDER

ISSUED: January 10, 1994

SHORT TITLE

Mountain Fuel Supply Company general rate case.

SYNOPSIS

By this Order the Commission has established a distribution non-gas revenue requirement for the Company of $155,362,477. This is based on an allowed rate of return on common equity of 11.00 percent and a rate of return on rate base of 10.08 percent. A decrease in revenue of $1,605,536 is required. In addition, three stipulation and settlement agreements are adopted involving interruptible rates, an incentive sharing mechanism for released upstream pipeline capacity, and pass-through treatment of the carrying costs associated with working storage gas. This Order and the stipulations respond to the industry restructuring effects of the Federal Energy Regulatory Commission's Order 636.

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COMMISSIONER STEPHEN C. HEWLETT DISSENTING IN PART 89

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I. PROCEDURAL HISTORY

On April 2, 1993, Mountain Fuel Supply Company (hereinafter "Mountain Fuel" or "Company") filed a request for a general increase in rates of $17,953,000.

On April 13, 1993, a prehearing conference was held in this matter pursuant to a notice of April 5, 1993. At the prehearing conference, appearances were entered by Mountain Fuel Supply Company, the Division of Public Utilities ("Division"), the Committee of Consumer Services ("Committee"), Geneva Steel, Energy Strategies, Inc., and the Utility Shareholders Association of Utah. The Commission ruled that all parties who made an appearance at the prehearing conference would thereafter be treated as parties to this proceeding.

On May 5, 1993, the Commission issued a scheduling order setting forth a tentative procedural schedule and requiring the parties to address the appropriate test year to be used in this case in prefiled position statements and at a May 6, 1993, hearing. Position statements were then filed by various parties to this proceeding.

A hearing was held on May 6, 1993, in which the position statements and prefiled testimony of various parties were submitted into evidence. The Company proposed a limited waiver of the 240-day requirement, on condition that a final order in the case is issued on or before January 10, 1994, to be effective on or before January 1, 1994. On May 24, 1993, the Commission issued its Order Regarding

Test Year and Revised Procedural Schedule setting forth separate procedural tracks for rate design and revenue requirement with a true-up hearing scheduled for December 6, 1993. The Commission also ordered a non-calendar test year ending October 1, 1993, for use in this general rate proceeding under conditions set forth in the order, including the limited waiver proposed by the Company.

On May 26, 1993, Mountain Fuel filed a Motion for Entry of Protective Order. On June 2, 1993, the Commission issued a Protective Order in this matter.

On August 3, 1993, the Company submitted a Motion for Further Interim Relief, requesting authorization for interim revenue relief of $4,328,000. In addition, the Company asked for an open season to implement interruptible sales and an increase to the current interruptible transportation rates to reflect assignment of supplier non-gas costs to these rate classes.

On August 3, 1993, the Commission cancelled a scheduling conference previously set for August 12, 1993. On August 6, 1993, the Commission issued a Notice of Hearing to consider the Motion for Further Interim Relief of the Company (later withdrawn) and to consider consolidation of the general rate case docket with the pending pass-through docket (93-057-04) so that common issues could be considered in one docket.

On August 24, 1993, the Commission issued its Notice of Hearing and Technical Conference and Revised Procedural Schedule. This notice set a technical conference and hearing for August 31, 1993, to consider a possible stipulation, consolidation of cases and the interim relief previously requested by the Company. The notice also postponed and held in abeyance various procedural deadlines.

On August 26, 1993, all parties in this proceeding who had submitted rate design testimony filed a Stipulation and Settlement for review by the Commission. The Commission considered evidence regarding the Stipulation and Settlement at a hearing on August 31, 1993. On October 19, 1993, the Commission issued its Order Adopting Stipulation and Settlement which adopted the provisions of the Stipulation and Settlement. This Stipulation included tariff provisions described in Exhibit 1 to be effective on November 1, 1993, and interim provisions effective September 1, 1993, as set forth in Exhibit 2.

On September 20, 1993, the Commission issued its Notice of Cancelled Hearing canceling the hearing which was scheduled for September 27, 1993, on rate design issues decided by the Commission's acceptance of the Stipulation and Settlement.

On October 4, 1993, the Commission issued a Notice of Technical Conference for October 13, 1993, regarding Account 191 issues. On October 6, 1993, the Commission issued a Notice to Parties directing Mountain Fuel and the Division to submit testimony regarding the appropriate interest payments on security deposits and the appropriate interest charges on late payments with testimony to be filed by October 25, 1993.

In addition to the parties appearing at the initial prehearing conference in this matter, the following parties filed petitions to intervene: Pacificorp, dba Utah Power and Light Company, the Federal Executive Agencies, the Utah Industrial Energy Users, Kennecott Corporation, et al, Nucor Steel, the Industrial Gas Users, Kern River Gas Transmission Company, the Utah Office of Energy and Resource Planning, Grand Valley Gas Company, and other various industrial transportation customers who intervened as a group. These Petitions to Intervene were all granted by the Commission.

Commencing on July 1, 1993, and on a monthly basis until the last filing of October 18, 1993, the Company submitted monthly updates to its test-year data. The final update reflected data for the test year ended September 30, 1993.

Pursuant to the schedule established by the Commission, the Company, the Division and the Committee filed written direct, rebuttal and surrebuttal testimony addressing the various issues in this proceeding.

On November 2, 1993, the Commission held evidentiary hearings regarding revenue requirement issues, including rate-of-return and capital structure issues. Also submitted into evidence was a second stipulation, identified as Settlement Exhibit No. 2, which addressed ratemaking of supplier non-gas and gas commodity costs. These hearings ended on Tuesday, November 9, 1993.

On November 23, 1993, the parties submitted Joint Exhibit Numbers 1 and 2, which contained an issue-by-issue reconciliation and analysis of each party for Commission review.

On December 6, 1993, the Commission conducted a hearing on true-up issues and heard oral argument on the revenue requirement issues.

On January 4, 1994, the parties submitted a third stipulation, identified as Settlement Exhibit No. 3, which addressed ratemaking for working storage gas reserves assumed by Mountain Fuel pursuant to the Federal Energy Regulatory Commission ("FERC") Order No. 636.

II. DISCUSSION, FINDINGS, & CONCLUSIONS WITH RESPECT TO DISTRIBUTION NON-GAS REVENUE REQUIREMENT

A. INTRODUCTION AND TEST-YEAR ISSUES

The non-calendar test year in this docket, October 1, 1992, through September 30, 1993, has been termed a "rolling" test year to account for the periodic replacement of forecasted with actual information during case proceedings. When testimony was first filed, actual (historical) information was available for 1992 only; all 1993 information was forecasted. By the end of the proceeding, all test-year information was actual, making the test year, in the opinion of Mountain Fuel, historical.

Mountain Fuel had proposed the non-calendar year, rolling test year as a compromise made necessary by our policy favoring an historical test year without post-test-year adjustments. The Company wished to include the industry-restructuring effects of FERC Order 636, which was scheduled to take effect on or before October 1, 1993. Preliminary indications were that the Division would argue for an historical 1992 test year, with post-test-year adjustments. The Committee had expressed a similar preference, strongly supporting an historical test year.

These positions were presented at a scheduling hearing held April 13, 1993. We stated that we had the authority to choose the particular test year best suited to the needs of the applicant, the parties, and the regulatory process. We expressed preliminary judgment that the proposed rolling test year probably could not be considered historical due to the difficulty of coordinating party investigation of information revisions with the hearing process, given the tight time demands of the docket.

Testimony indicated three ways to bring the key event, FERC Order 636, into the test year. It could be considered as a post-test-year adjustment to an historical 1992 test year, as an event in a fully forecasted 1993 test year, or as part of a rolling test year which, at the end of the hearing, would consist of historical information only. A fourth but not advocated alternative would have been to conduct two rate cases, the first using an historical 1992 test year and the second an historical 1993 test year. This was viewed as too costly to seriously entertain. In Mountain Fuel's opinion, a rolling test year seemed the least objectionable departure from our test year policy. The Division advised that proper auditing of a rolling test year would be difficult to accomplish.

Our May 5, 1993 Scheduling Order asked parties to consider: (1) under what circumstances we should deviate from an historical test year; (2) under what circumstances post-test-year adjustments should be considered; (3) whether the Division could adequately audit a rolling test year or a projected one; (4) how the Company would be advantaged by an incomplete audit, should that occur; (5) how the rolling test year would distribute the risks of regulatory lag; (6) disadvantages to regulation of a test year not corresponding to the calendar year; (7) whether the effective date of FERC's Order 636 would be within the proposed test year; (8) whether the effects of that Order on Questar Pipeline Company would be within the test year; and (9) whether the proposed schedule placed key hearings so close to the end of the 240-day period within which a revenue requirement decision had to be rendered that our deliberation and order preparation would suffer. Answers and the parties' positions on test year were filed April 30, 1993. On May 6, 1993, an evidentiary hearing on test year issues was held. By that time, parties had stipulated to the rolling test year alternative.

Our Order Regarding Test Year and Revised Procedural Schedule was issued May 24, 1993. We determined that the October 1, 1992 to October 1, 1993, compromise rolling test year proposed by the parties would be acceptable, with caveats intended to protect the regulatory process, and noted on page 6 of that Order three potential problems:

> First, the period for review, audit, and assessment of the reasonableness of the Company's rolling forward test year may be too short to be adequate. Second, problems may be created because the test year does not match the Company's fiscal year and thus does not include year-end accrual adjustments, corrections and audit information. Third, the time permitted for the Commission to issue its order in the docket, given the interruption of the December holiday season, is short.

We requested that the Division and the Committee critique the rolling test year at the end of the proceeding.

The Division's experience with this form of test year was negative, according to its witness, Chet Sullivant. He stated: "The Division and the Committee are disadvantaged and put in the position of having to respond to a number of changing situations and facts without having enough time to completely do the job, particularly with the limited resources that we have." The Division pointed out that the test year did not represent a normal operating cycle, made more work because two years of information had to be examined, and seriously strained limited resources at the end of the proceeding.

The purpose of this non-calendar test year was to allow the Company to go forward with a rate increase request to include certain adjustments within an historical test-year which our recent test-year policy would not allow. We recognize that the test year caused difficulty. We anticipated some of the problems in our Order of May 24, 1993. In addition, there were record-keeping problems created by the periodic updates of test year information and consequent revision and refiling of exhibits. Presentation and cross-examination of witnesses was more difficult, but the chief problem was the difficulty caused regulatory agencies in the auditing of the completed test year. We conclude that the net result was diminished regulatory effectiveness and that will be a significant consideration for similar proposals in any future rate case.

The parties have indicated that the Commission's preference for historical test years combined with its policy barring post-test-year adjustments was a source of test year difficulties. We acknowledge that is true, but we have carefully considered the test year problem in previous dockets, and the rationale for the policy has been clearly stated. (See Report and Order, Docket No. 92-049-05, In the Matter of the Request of US WEST COMMUNICATIONS, Inc. For Approval of an Increase in Its Rates and Charges, April 15, 1993, pp. 9-15.)

In the present docket, we were confronted with FERC Order 636, a uniquely important, industry-restructuring event, which, though outside the preferred historical test year, would influence utility performance during the rate-effective period in ways that could not be ignored.

Thus, like the parties, we have struggled with a non-calendar, rolling test year. The problems experienced with the use of a non-calendar rolling test year will be considered in the context of future deliberations on test-year issues.

B. COST OF CAPITAL

1. Introduction

In our Order dated November 21, 1990, the most recent Mountain Fuel rate case docket, 89-057-15, we found 12.1 percent to be the reasonable rate of return on common equity capital and allowed it for ratemaking purposes. All witnesses in this present proceeding have testified that cost of capital has declined since then, and that the circumstances facing local gas distribution companies have changed, most particularly as a result of federal regulatory action. This raises the question whether new business risks now affect Mountain Fuel's cost of equity capital. On balance, we determine that an allowed rate of return on equity of 11 percent is proper for ratemaking purposes in this docket. With the appropriate capital structure, the overall rate of return allowed for the rate-effective period is 10.08 percent.

2. Positions of the Parties

We summarize the testimony of R. Charles Moyer for Mountain Fuel, Judith Johnson for the Division, George R. Compton for the Division on a point of rebuttal, and John B. Legler for the Committee.

Dr. Moyer recommended a 12.1 percent rate of return on equity. He assessed the effect of declining interest rates, as an indication of changes in the general economic environment, on cost of capital. Offsetting this, he stated, are increases in business risk owing to such factors as the Federal Energy Regulatory Commission's (FERC) Order 636. As another example, he suggested that large industrial customers might now find it profitable to leave Mountain Fuel's system to take service on the new Kern River pipeline. To quantify investors' required return, he employed the Discounted Cash Flow (DCF) model, and used risk premium and comparable earnings approaches to test the reasonableness of his principal estimates. He analyzed ten comparable companies as proxies for Mountain Fuel, which does not issue common stock. His comparison also addressed the regulatory consideration that Mountain Fuel's allowed rate of return on equity should reflect that which investors could earn on investments of similar risk. The range of reasonable estimates resulting from his analysis was 11.6 percent to 13.2 percent.

Ms. Johnson recommended an equity return of 11.0 percent, selected from a range of return estimates she judged reasonable extending from 10.1 percent to 11.7 percent. These estimates were derived by application of the constant growth form of the DCF model, the form used by Dr. Moyer, to the set of comparable companies he had selected. She compared this result to her estimate of a risk premium, again the test used by Dr. Moyer. The specific risk premium was not the same, however, because witnesses could not agree about the relationship between the period's declining interest rates and the proper size of the premium. They also differed in the estimates used for the variables in the DCF equation and employed somewhat different criteria to identify non-representative calculations for removal from consideration. Ms. Johnson testified that Mountain Fuel had performed well under the rate of return awarded in 1990, and that cost of capital had declined since that time. Mountain Fuel's conservative capital structure justifies an award at the lower end of the range of reasonable estimates, she stated. But in order not to reduce equity return too much in a single decision, which she described as meeting an "objective of continuity," she recommended 11.0 percent rather than a point at or below the middle of the range of her estimates.

In rebuttal testimony, Dr. Compton took issue with Dr. Moyer's assertion that FERC Order 636 had made Mountain Fuel more risky than Questar Pipeline Corporation, and had increased Mountain Fuel's cost of equity above Questar Corporation's. Because the market does not deal directly with Mountain Fuel, this is Dr. Moyer's qualitative assessment. Dr. Compton attempted a quantitative estimate. He used the DCF model to examine equity returns of gas distribution companies, pipeline companies, and integrated companies like Questar Corporation, both before and after FERC Order 636. The results of this analysis did not support Dr. Moyer's assertion.

Dr. Legler recommended 10.8 percent, the middle of a range of estimates of 10.4 percent to 11.2 percent. Dr. Legler cautioned the Commission to be aware that witnesses' subjective judgments play a large role in reaching a recommended rate of return. The objective appearance of estimation models may mask judgment's role, he said. He testified that the Commission must weigh all relevant considerations, not just the results of financial models, in order to select a rate of return from the zone or range of reasonable estimates provided by witnesses. He applied the constant growth form of the DCF to a group of companies having risk and other important characteristics similar to Mountain Fuel. He performed a risk premium analysis, and applied the Capital Asset Pricing Model (CAPM) to these companies and to Questar Corporation. He testified that cost of capital had declined, and noted that all regulatory commission equity decisions for gas distribution companies since June 1993, had been below 12.0 percent. He asserted that business risks, including the effects of FERC Order 636, are fully reflected in the stock prices used in the estimation models and should not be the basis for further adjustment. Dr. Legler testified that Mountain

Fuel's capital structure is unusually conservative. He recommended an adjustment to reduce the equity component, or, alternatively, a reduction in the equity award to reflect the Company's lower financial risk.

3. Rationale and Findings

We find reasonable the approaches employed by the witnesses to estimate cost of equity for Mountain Fuel. In most important respects these approaches are the same, and they are consistent with the findings and conclusions about estimation method we have reached in recent dockets.

All witnesses share a conception of the equity cost estimation problem. In general, they agree that certain models are preferable and that comparable companies must be analyzed. Points of disagreement are clearly stated on the record, and some have been quantified. They state that the cost of common equity is equal to investors' required return, which is the competitively determined market capitalization rate. Though models derived from financial theory are used to estimate this rate, they agree other considerations must and should influence the Commission's choice of allowed rate of return on equity. These include the assumptions and data upon which modeled outcomes are based, the effects of general economic conditions, and the business risk faced by the firm. All are subject to individual judgment and interpretation.

We turn first to the DCF model. Because price is a variable, this model explicitly considers the opportunity cost of capital. This is the notion that the rate of return necessary to induce an investor to purchase a firm's common equity must be commensurate with what could be earned in similar risk alternatives. Behind this statement is the assumption that markets efficiently digest all relevant information so that price reflects a risk-adjusted return relative to that available from risk-adjusted alternatives. This conception is in the spirit of the regulatory guideline that a utility should be allowed the opportunity to earn a return comparable to that available in similar risk alternatives. It is this model, in its "constant growth" form, that the witnesses rely upon. We find, consistent with our decisions in other dockets, that it is reasonable for them to do so. In those dockets we stated several reasons for our preference for this model. First, it is straightforward and the assumptions behind it are widely accepted. Second, the data needed to estimate its variables is readily available. Third, it corresponds well to the concept of opportunity cost. Fourth, under this model it is relatively easy to determine the reasons why the results recommended by various witnesses differ.

Price, indicated dividend, and expected dividend growth must be estimated to calculate equity cost using the DCF. Witnesses do not agree on the values for these variables, though price is the least problematic. Each uses a three-month average stock price to avoid unrepresentative short-term (even daily) price swings. This is reasonable in our judgment. The record shows that differences in the price variable are mostly due to the time at which testimony was prepared. We used the updates that were submitted at the end of the hearing.

Choice of indicated dividend and the dividend growth rate is more difficult. We address each in turn.

The DCF calls for an indicated dividend. Witnesses agree that the current quarter's dividend, multiplied by four, is the correct starting point to derive it. Testimony differs, however, about how to account for investors' expectations that the dividend will increase during the coming year. The first proposition would increase the dividend by applying the annual growth rate (the growth rate we must find applicable as the DCF variable) to the annual dividend. The second employs the "FERC formula," which uses half the growth rate, implying that investors expect dividends to increase half a year ahead. This has been found by the FERC to be true on average. Use of the full growth rate to increase the dividend could mean investors expect dividends to increase at the start of the period. We reject the argument that because dividends are paid quarterly, the impact of quarterly compounding must be considered. We find it to be irrelevant, and, in any event, research shows the impact of quarterly dividend payment to equate to the FERC treatment.

We are not persuaded to consider the impact of quarterly compounding of dividends. The need for such an adjustment is too uncertain and unclear. In any event, there is but a resultant cost of equity difference of about 20 basis points between the two approaches. In past dockets, we have relied on the FERC approach, using half the growth rate. Again in this docket, it is reasonable to assume that investors expect dividends to increase during the coming year and not at the beginning of it. There is no new evidence to the contrary. We therefore conclude that the indicated dividend should be four times the current quarter's dividend, increased by half the expected growth rate.

Growth rate estimation is the point of greatest dispute. We need not resolve, however, the witnesses' debate about the use of earnings versus dividend forecasts. As a forecast, each approach is an exercise of informed judgment about an uncertain future. We do not believe either investors or regulators rely on forecasts uncritically. Without dispute, DCF theory calls for the dividend growth rate. Evidence shows that dividends are forecast to grow more slowly than earnings during the next five years. Longer term growth has not been addressed, even though the DCF assumes both a longer-term horizon and constant earnings and dividend growth. No witness suggested employing a non-constant growth DCF analysis. Over the longer term, dividends and earnings growth should converge. We are not convinced that earnings growth is the proper rate to use, though there is doubt about relying on a single dividend forecast. There is, however, only a 20-basis point difference between the use of earnings growth forecasts and a blend of earnings and dividend growth forecasts. As is the case when expert testimony yields no single answer, and no party successfully disposes of the arguments of the others, the Commission must fashion a reasonable outcome. We can be guided by the witnesses' tendency toward compromise, whether reached by using a larger set of forecasts and from different sources or by considering both earnings and dividend forecasts. Given the evidence in this docket, the use of both earnings and dividend forecasts to bound the problem of estimating the required growth rate is the most reasonable approach and we will accept it. But we must note that regardless of which source is used for the growth rate, when properly updated for the latest information, the differences produced are of minor significance.

Each witness indirectly measures equity cost for Mountain Fuel by applying the DCF to a set of comparable companies. These are selected on the basis of risk and other important characteristics. Companies comparable to Mountain Fuel are used rather than Mountain Fuel itself or its parent, Questar Corporation. We find this to be reasonable because Mountain Fuel does not issue equity securities, and Questar Corporation, which does, differs too much from Mountain Fuel to be used, uncritically, as a proxy.

When the DCF, fitted with the price, indicated dividend, and growth variables we have found reasonable, is applied to comparable companies, a range of equity cost estimates extending from 10.1 percent to 11.7 percent results. The upper end may be lower when the latest information is used and consistent application of criteria to exclude unrepresentative growth estimates occurs. The record is a bit ambiguous here. Before finding this to be the zone or range of reasonable estimates, we must consider application of other methods as checks on reasonableness of DCF estimates, the testimony on the special risks of industrial bypass and FERC Order 636, and the relationship of capital structure financial risk to equity return.

One can test DCF results using a risk premium method. In theory, bonds are less risky than common stock, so investors require a premium above bond yield to hold common stock. The sum of bond yield and risk premium is equity cost, but the risk premium itself must be estimated. Witnesses do not agree on the size of the risk premium. The differences center on the effect of current market conditions, including the level and behavior of interest rates, on the size of the risk premium. It is not necessary in this docket to resolve this technical point. There are other tests available, including the application of the DCF to Questar Corporation, the analysis of comparable companies, and the application of the Capital Asset Pricing Model (CAPM) to both comparable companies and Questar Corporation. Without repeating what we have said in other orders about these methods, we find that the results of these reasonableness tests support the witnesses' DCF analyses. Technical disputes about these methods aside, we find that the DCF, applied in accordance with our findings, produces reasonable cost of equity estimates.

We choose not to further adjust equity cost estimates to account for the FERC Order. We believe it is too soon to tell whether Kern River poses a problem, or is a net benefit, to Mountain Fuel's general body of ratepayers. The actions of management, particularly with respect to gas supply, will in large part tell this tale. At this time there is no need to adjust equity cost estimates for the alleged effects of these on the business risk Mountain Fuel may face. We conclude that the range of reasonable equity cost estimates, or required returns, from which allowed rate of return on equity will be drawn, extends from 10.8 percent to 11.7 percent. This is the range produced by the witnesses' point recommendations, adjusted to bring Mr. Moyer's recommended 12.1 percent to 11.7 percent to correspond to DCF results. The mid-point of this range is 11.25 percent.

Witness testimony, aside from the bypass and FERC Order 636 risk argument just rejected, holds Mountain Fuel to be about average with respect to comparable companies. This might support an equity return award at the mid-point. But there are other considerations. We find that Mountain Fuel's capital structure or financial risk is low relative to comparable companies. Though the evidence is not sufficient to support use of a hypothetical capital structure, reduced financial risk should be reflected in the equity return we allow. Selection of a return from the lower end of the range will accomplish this. Moreover, as we have found in previous dockets, the lower end is appropriate for companies, such as Mountain Fuel, having little or no need to raise capital in the market during the rate-effective period. Additionally, more than half of its total costs are recovered at no risk in a pass-through balancing account. Combined, these reasons lead us to 11 percent, which we conclude is a just and reasonable rate of return on equity for the ratemaking purposes of this docket. We note that the calculation of a pre-tax interest coverage ratio at an 11 percent equity return, taken as an indicator of financial health, shows a ratio well within the range for A-rated companies.

With this adjustment for financial risk, we find it is proper to use Mountain Fuel's actual capital structure to derive overall rate of return on rate base. That structure consists of 43.82 percent long-term debt at a cost of 9.06 percent, 2.59 percent preferred stock at a cost of 8.38 percent, and 53.59 percent common equity at a cost of 11.00 percent. The resultant rate of return on rate base, which we conclude is reasonable, is 10.08 percent.

C. RATE BASE ISSUES

1. Undisputed Issues

The test year rate base is a twelve-month average using the 13 months September 1992, to September 1993, with each September weighted as half a month. Rate base, excluding gas stored underground and cash working capital, was $361,453,270. There are five adjustments to rate base that are not in dispute.

As prescribed by the Wexpro Agreement, 6.3 percent of plant accounts related to production are costs assigned to the Wexpro operation. This results in a decrease in rate base of $2,991,063.

The Company has a program in which employees may bank unused vacation for use in a subsequent year. The Committee has argued that the net balance, banked vacation earned less banked vacation taken, should not receive rate base treatment since the banked vacation earned during the test year is included in the test year payroll costs. Using an average of the monthly net banked vacation balances for the thirteen months ending December 31, 1993, as provided by the Company, results in a decrease in rate base of $505,000.

The Company offers a program, termed the Equal Payment Plan, which permits ratepayers to make equal monthly payments based on annual use in order to eliminate the seasonal variation in bills. Since the annual period begins in July, a warm weather month, the Company pre-collects revenues from participating ratepayers. The Committee argued that the average net credit balance in the Equal Payment Plan, which accounts for the test year, should be recognized as an offset to rate base. This results in a decrease in rate base of $3,591,417.

Since the test year has been adjusted to include the full cost of postretirement benefits other than pensions (PBOPs, see

Section II.D.1.c. below), PBOP prepayments will no longer exist. As a consequence, the Division argued that PBOP prepayments should be removed from rate base. This results in a decrease in rate base of $751,000.

All parties agree to the inclusion of the costs of demand side management. This results in an increase in rate base of $72,795. A corresponding adjustment is made to increase depreciation expenses.

2. Working Gas Storage

One impact of FERC Order 636 is the transfer of responsibility from Questar Pipeline Company (QPC) to Mountain Fuel for providing working gas inventory required to inject and withdraw gas from underground storage. At issue among the parties is the amount and cost of the working storage gas to be included in the test period rate base.

The Company argued that the test year underground storage balances of QPC, less 3 Bcf to be retained by QPC, provide amounts which are unrepresentative of expected future conditions. Due to the effects of a colder than normal spring of 1992 followed by a colder than normal winter of 1992-93, the balances for the test year are abnormally low.

To obtain a more appropriate quantity of storage gas, the Company used average monthly balances from January 1990 to September 1993. Since QPC's 3 Bcf is not a constant monthly balance in storage, Mountain Fuel's share was obtained by multiplying the average historical monthly balances by the ratio of Mountain Fuel's storage capacity to total storage capacity after implementation of FERC Order 636, or 75.41 percent. The Company proposed pricing the average adjusted balances using the average price of gas in storage for each month of the test period. This produced the Company's requested increase in rate base of $16,681,351.

Both the Division and the Committee argued for the use of the 12-month average of the monthly balances during the June 1992 to June 1993 period. This produced a requested increase of $13,734,479.

At the urging of the Commission the parties presented a stipulation of issues related to the ratemaking treatment for working gas in storage on January 4, 1994. The stipulation proposed use of a 13-month rolling average of the working storage gas balance, adjusted to produce a monthly average balance of $15 million for the test year. The carrying costs associated with the updated 13-month rolling average balances of working storage gas were proposed to be recovered in the Company's 191 Account. The 191 Account provides for pass-through recovery of costs in which the risk of changes in costs is borne by ratepayers.

Given the lack of adequate history of post-636 management of working storage gas and the resultant inability to adequately anticipate storage requirements, this proposal is a reasonable compromise of party positions and is therefore accepted. The

Stipulation is an interim treatment which will remain in effect until the next general rate case. At that time an adequate history for general ratemaking purposes will exist and these costs are then intended to be recovered through general rates.

3. Accumulated Deferred Income Tax Issues

The Committee recommended excluding from the test period those deferred income tax items which were related to one-time events, not reflected in a prior test period and therefore not included in rates, or were derived from expenses for which ratepayers should not be responsible. These items included deferred tax debits of $5,737 for accrued interest expense, $31,603 for amortization of organizational costs, $11,404 for Questar organization costs, $202,991 for Mountain Fuel Resources reorganization, $1,329,683 for contributions in aid of construction, $8,314,900 for unbilled revenue, and $5,231 for unallowable contributions. Exclusion of these debit items would increase accumulated deferred taxes and reduce rate base. The Committee also recommended disallowing a deferred tax credit of $95,099 for executive insurance retirement.

In Docket No. 89-057-15 the Commission adopted the South Georgia method under which all tax timing differences are normalized and the undeferred balances for all timing differences are amortized over a 17-year period. The Company provided a document showing the calculation of the tax and book basis and timing differences and the computation of the South Georgia amortization necessary to recognize the flowback of the undeferred balance as of December 31, 1986. All items that the Committee recommended for disallowance were separately identified and included in the South Georgia amortization except contributions in aid of construction and unallowable contributions. The Company maintained that contributions in aid of construction, though not explicitly identified, were reflected in the calculation. The Company claimed that the Committee was attempting to change the South Georgia method by selectively excluding items that increase cost, i.e., deferred tax debits. We agree with the Company's position.

The Company stated that deferred debits associated with the amortization of organization costs, Questar organization costs and contributions in aid of construction will be removed from its books when the South Georgia amortization is complete. With respect to reorganization costs, the Company stated that the resulting deferred tax was included in the test periods used in both Docket No. 89-057-15 and the current case.

It is our assumption that all items included in the South Georgia amortization will be removed from the Company's books when the 17-year amortization period has ended, with the exception of unbilled revenues. We reject the Committee recommendation to exclude the deferred tax items, with the exception of unallowable contributions and unbilled revenues, because of the selectivity that we find to be inappropriate.

All parties agreed that the deferred debit of $5,231 related to unallowable contributions should be excluded from the test year. We accept this adjustment.

The Committee stated that the deferred debit related to unbilled revenue is appropriate to include as a rate base item only to the extent that the unbilled revenue itself has been included for ratemaking purposes. The Committee then claimed that the Company had neither reflected on an accrual basis nor included in rates the revenue associated with gas that had actually been delivered to ratepayers, but was as yet unbilled. In order to provide a proper matching of revenue and taxes with test year costs, the Committee recommended that unbilled revenue net of gas costs and the related deferred tax debit be amortized into rates over a five-year period.

The Company claimed that by including 12 months of temperature adjusted distribution non-gas revenue it had included the unbilled revenues in the test year. Consequently the Company argued that the Committee's standard was met, no revenue was unbilled and no adjustment to test year revenue or deferred taxes was necessary. Both the Company and the Division noted that the Committee's calculation failed to include supplier non-gas costs as a relevant gas cost associated with unbilled revenue for tax purposes.

Although unbilled revenue was not addressed in its original testimony, the Division agreed in concept with the adjustment proposed by the Committee, stating it thought the Committee arguments were substantially correct. The Division claimed that it would be unfair for unbilled revenues to be excluded from the ratemaking process on the revenue side while requiring ratepayers to pay the carrying charges on the deferred tax debit associated with unbilled revenue on the rate base side. In addition, the Division cited a prior Commission decision in which Utah Power & Light Company was ordered to recognize unbilled revenue for book and ratemaking purposes in Docket Nos. 78-035-21/79-035-03.

The Division calculated an adjustment to increase test-year revenues by $2,011,000, a dollar amount of unbilled revenue net of commodity and supplier non-gas costs. This is the first year of a five-year amortization period. The Division also calculated an adjustment to decrease test year deferred income taxes by $4,813,332, representing the effect of flowing back ratably a $9,513,000 debit balance over five years.

Unbilled revenues and corresponding deferred taxes are directly related to gas sales which in turn, under normal conditions, are directly related to the size of the utility system. In order to properly match test-year revenues with test-year expenses including taxes, and to maintain accrual accounting for deferred income taxes, we find it appropriate to phase into rates unbilled revenues and the corresponding deferred taxes over a five-year period. Since it is appropriate to include supplier non-gas costs in the calculation of the revenue adjustment, we adopt the recommendation of the Division.

This adjustment increases revenue by $2,011,000 and decreases deferred income taxes by $4,813,332.

We request the Division to analyze by September 30, 1994, the Company's deferred income tax balances. We will schedule a technical conference to identify the issues to be studied.

4. Cash Working Capital

Cash working capital was calculated in this docket using the lead-lag study for the 12 months ending December 1989, developed in Docket No. 89-057-15. The Committee recommended that a check clearing lag of 9.435 days be introduced and applied to those expenses which the Company does not pay electronically. The Committee also recommended that the expense lag associated with sales taxes should be reduced from 69.56 to 45.10 days to reflect the monthly rather than quarterly remittance of sales tax collections.

While the Committee used a sample of one hundred checks to derive a check clearing lag of 9.435 days, the Company demonstrated that most of its expenses are paid electronically. Furthermore, it argued that if a check clearing lag for expenses is appropriate, then it is also necessary to introduce a check clearing lag for revenues. The Division argued that it is inappropriate to update a select few elements of the lead-lag study.

The elements of the lead-lag study, derived from 1989 information, do not match the test year. Given the Company's demonstration, inclusion of a new element in the lead-lag study may not provide a better match with test year information. Selective updating of elements may or may not provide a better match. If elements of the lead-lag study need to be updated, then it is necessary that all elements be updated in a new lead-lag study, preferably one that matches the test year. The Commission therefore rejects the recommendations of the Committee regarding the lag days associated with check clearing and sales taxes.

The Committee also recommended that interest expenses and preferred dividends be included in the calculation of cash working capital. The Committee argued that the funds used to pay interest expenses and preferred dividends are collected from ratepayers monthly. However, payments for interest expenses are made semi-annually and payments for preferred dividends are made quarterly. Therefore, the funds collected represent a source of cash working capital to the Company which should be recognized as an offset to cash working capital.

In Docket No. 82-035-13 we adopted a method for determining cash working capital that excludes consideration of depreciation, interest expenses, and preferred and common dividends. That method has been reaffirmed in recent Commission orders and applies to PacifiCorp and U.S. West as well as to Mountain Fuel. If this method is to be changed, a strong burden of persuasion will first have to be met which must include a comprehensive analysis of all four of the above-mentioned items. Lacking such an analysis in this docket we reject the Committee's recommendation to include interest expenses and preferred dividends in the calculation of cash working capital.

Cash working capital is calculated as the sum of operation and maintenance expense, gas purchases, and taxes, all divided by 365 days, times the net lag day factor. The net lag factor from the 1989 lead-lag study is 3.266 days. Given Commission decisions, operation and maintenance expense equals $88,707,281 (see Section D. below) and income taxes equal $7,550,006 (see Section E. below). Gas purchases equal $205,672,000 and non-income taxes equal $10,226,881. Therefore, cash working capital is $2,793,156.

D. OPERATING EXPENSES

1. Annualization of Labor Expenses

a. Normalization of the O&M Expense Percentage

In Docket No. 89-057-15, a normalized expense percentage of 84.2 percent was uncontested. It was used to allocate labor and labor overhead costs to operations and maintenance expense. The Company recommended continued use of the 84.2 percent expense percentage. Since it had no plans for any large future expansion, the Company argued that years reflecting high levels of construction should be considered abnormal. These were years in which relatively large amounts of labor were capitalized and relatively small amounts were expensed. The Company stated that the normalized expense percentage used in Docket No. 89-057-15 was determined by calculating an average of actual annual expense percentages and excluded years when major expansions occurred. The Company claimed this figure would be representative of the rate-effective period and should be used in this case.

The Division recommended decreasing the expense percentage to 83.4 percent. This is an average of the percentages of the actual labor and labor overhead costs that were expensed during the five-year period 1988 through 1992. The Division claimed the Company was inappropriately selective to treat only high construction years as abnormal, citing the Kern River expansion in 1992 which was neither planned nor anticipated in Docket No. 89-057-15. The Division also argued against using results for the eight months of 1993, claiming that due to fluctuations in the monthly expense percentages, partial year information may not adequately represent the annual percentage.

The Committee recommended decreasing the expense percentage to 83.9 percent. This is an average of the percentages of the labor and labor overhead costs that were expensed during the three and one-half year period from 1990 through June 1993. The Committee claimed that it is necessary to treat high and low construction years as normal in order to smooth annual variations and that its time period gives effect to a construction cycle typical of Mountain Fuel. By treating high construction years as abnormal, the Committee argued that rates will recover more expense than will occur over time.

Excluding high construction years from the calculation of the average expense percentage on the basis that the Company has no plans for any large future expansion alters conclusions drawn from historical experience by Company expectations of the future. With the exception of expected dividend growth in the determination of the cost of capital, use of future information in this case has been minimized by reliance on an historical test year and consideration only of changes which occurred during that test year. For ratemaking purposes, recent experience is preferred to Company expectations of the future. This principle holds as well for the years to be included in the calculation of an average expense percentage for normalization purposes.

Evidence showed that the expense percentage averaged 85.2 percent for January 1993 through June 1993, 84.7 percent for January 1993 through August 1993, and 83.7 percent for October 1992 through September 1993. The 1993 annual expense percentage cannot be inferred from the available data. It is also circular reasoning to use incomplete 1993 information in the construction of an historical average to replace an unknown or variable 1992-1993 test year figure. Removing the 1993 information from the Committee's review period yields a 1990-1992 average of 83.4 percent, equal to the Division's recommendation using 1988-1992.

Given large annual variations in the expense percentage and absent fundamental changes, lengthening the time period increases confidence that the average represents normal conditions. Since the Division uses a longer period than the Committee, and both reach into the test year, this principle favors the Division's recommendation. The clearest fundamental change occurred in 1984 when the Company reorganized and the transmission function was removed from state jurisdiction and placed under federal jurisdiction. The evidence shows that from 1985 through 1992, the annual expense percentage averaged 83.1 percent. In light of this evidence, the Commission finds the Division's recommendation to be most reasonable and adopts a normalized expense percentage of 83.4 percent for use in this docket.

b. Annualization of Labor Costs

The Company recommended that test year labor expenses be annualized using September 1993 costs, the final month of the test year and a month which included a 5 percent merit wage increase. The Company stated it was following past practice in that labor was annualized at year-end levels in its last rate case, Docket No. 89-057-15. Debt refinancing and PBOP expenses are annualized in this case at year-end levels. The Committee supported the Company's annualizing adjustment.

The Division was opposed to annualizing only a selected wage increase at the end of a test year favorable to the Company. From its analysis of the last five years, the Division concluded that customer growth produced growth in revenues which exceeded the growth in expenses and capital costs, rendering unwarranted a single adjustment to reflect only an increase in wages. Further, by using an October 1992, through September 1993, test year, the Division claimed employment was higher than normal and revenues were lower than normal, further distorting the matching of costs and revenues.

In prior rate proceedings we have allowed adjustments to annualize price changes which occur during the test year and will continue to do so in this docket. Since neither revenues nor investments have been annualized at year-end levels, proper matching with expenses can most reasonably be achieved by annualizing the labor price increase at an average of employment for the test year. Test year labor and labor overhead costs, excluding incentive compensation, were $60,953,909. The Division calculated $2,297,000 to be the increase in labor costs due to the wage increase using the average-of-year employment we have approved.

c. Postretirement Benefits Other than Pensions (PBOPs)

The Company recommended that the expenses of PBOPs, a component of overhead related to labor, be annualized along with direct labor costs. The proposed adjustment reflects the change in accounting from a pay-as-you-go or cash basis to full accrual of PBOP expenses under Statement of Financial Accounting Standards No. 106. Both the Division and the Committee supported this adjustment. We accept this change in accounting for PBOPs. The adjustment is an increase of $3,350,000 in labor overhead costs.

d. Pension Expense

The Company recommended that pension expense, a component of overhead related to labor, be annualized along with direct labor costs. The Committee supported this adjustment. The Division, opposed to annualizing labor cost changes, also opposed annualizing pension expenses. Since pension expense is an overhead cost that varies directly with labor cost, and given our acceptance of the annualized labor adjustment (in b. above), it is appropriate to annualize pension expense. This adjustment increases test year labor cost by $78,679.

e. Tax Preparation

The Committee proposed that the expenses for officer compensation for tax preparation be disallowed. The Committee stated it is inappropriate that such expenses, linked to a perk available only to the Company's highest-ranking officers, be recovered from ratepayers. The Company claimed that this is a small but normal component of officer compensation and is a reasonable business expense. The Division took no position on this issue. We accept the Committee's recommendation. This adjustment is a decrease of $2,185 in labor costs.

2. Annualization of Payroll Taxes (FICA)

The Company recommended that FICA taxes be annualized along with labor costs. While the Division did not support annualizing labor costs, it did agree that a payroll tax adjustment would be needed if the Commission were to adopt an adjustment annualizing labor costs. The Committee did not support this adjustment. As a cost related to employment, and given that we accepted an adjustment annualizing labor costs at average-of-year employment, it is reasonable to accept this adjustment also. This adjustment is an increase of $74,039 in indirect labor costs.

3. Gas Supply Employees Under FERC Order 636

At both the federal and state level Mountain Fuel has been directed to assume responsibility for its supply of gas. With the implementation of FERC Order 636, Mountain Fuel has assumed the gas supply function which previously had been performed by Questar Pipeline. The Company proposed an adjustment of $1,901,538 to cover the additional labor expenses associated with 33 new employees, which included the transfer of 21 employees from Questar Pipeline. The Committee supported the Company's proposed adjustment but urged the

Commission to require after one year a cost/benefit analysis of the reasonableness and cost of the gas supply organization.

The Division opposed the Company's adjustment. The Division argued that the costs associated with the 21 employees transferred from Questar Pipeline have not been removed from Questar Pipeline rates. Including these costs in Mountain Fuel's rates would lead to double recovery of these expenses from ratepayers. The Division recommended that labor expenses be increased by only $606,000. Division witness Sullivant testified, however, that the Division would not have challenged these costs if Mountain Fuel and Questar Pipeline were not affiliated.

The Company stated that the reasonableness of Questar Pipeline rates is determined by the FERC. Under the filed rate doctrine, rates filed by Questar Pipeline with the FERC are not lawfully subject to state disallowance, either directly or indirectly.

Several times in this docket the Commission voiced its concerns about whether the costs of the 636 employees would be included in the rates of both Mountain Fuel and Questar Pipeline, resulting in the double recovery that the Division alleged. We have considered the testimony of the Division and the Company as well as the briefs filed by each on the "filed rate doctrine." The Company maintained that this doctrine precludes Commission consideration of possible double recovery of these expenses, while the Division disagrees.

In Docket No. 89-057-15 we ordered the Company to assume its own gas supply planning function and in Docket Nos. 91-057-11 and 17 we ordered the Company to perform its own gas purchasing. Indeed the major thrust of FERC Order 636 was to force pipelines out of the merchant function and to require local distribution companies to competitively purchase gas supplies from producers. The Division has testified that the employees in question are now employed by Mountain Fuel and associated costs are being incurred by the Company. .

The basis of current rates for Questar Pipeline Company is the costs and revenues in its last Section 4 rate case. In October 1992, Questar Pipeline Company filed for an increase in rates of $9 million to cover what it called stranded and new facility costs due to implementing FERC Order 636. The FERC rejected this request stating that a full Section 4 rate case would be required in order to consider other aspects of Questar Pipeline's cost of service and to properly match revenues and costs. One can presume that the result would have been the same had some party petitioned the FERC to reduce rates for Questar Pipeline because the 636 employees would no longer be part of its expenses.

While the costs of the 636 employees were undoubtedly included in setting rates in that proceeding it cannot be said that they would be doubly recovered in 1994. The rates set in the last

Questar Pipeline Section 4 rate case did not include the so-called stranded and new facility costs or the PBOPs costs for Questar Pipeline Company, nor were the revenues the same as they are or will be in 1993 or 1994. The expenses of a regulated company are what they are year-by-year, not what they were in whatever test period on which rates were last determined.

Rates are set by this Commission and the FERC on the basis of a snapshot in time with its associated revenues and expenses. Rates will be set by this Commission on the basis of the 1992/1993 test-year snapshot which includes the 636 employee expenses. If the Division feels the Questar Pipeline Company rates are too high it should file at the FERC for a Section 4 rate case. More specifically, the Commission expects the Company to be an active advocate before the FERC to seek minimum pipeline rates, whether from its affiliate or not.

We direct the Division to perform an analysis of the Company's gas supply organization after one year of operation.

4. Incentive Issues

a. Incentive Compensation

The Division and the Committee question Mountain Fuel's incentive compensation plan[1], testifying that it is oriented toward

[1] Of four Questar Corporation and Mountain Fuel incentive compensation plans mentioned in testimony, three are at issue. These are: (1) Questar's Annual Management Incentive Plan (QAMIP, for managers), for which a substantial share of expenses are

the wrong goals, is impermissibly costly to ratepayers, and is flawed by its failure to distinguish and reward only what an employee is personally responsible for accomplishing. To determine program expenses that are properly recoverable in rates, we therefore must address incentive compensation plan design. Our concerns center on the choice of appropriate goals and whether employee awards should be based on outcomes outside their control.

Division witness Mecham testified that incentive compensation is a reasonable and proper way to motivate employees. He stated that goals are the key to an acceptable plan, in that goals ought to advance the legitimate interests of both shareholders and ratepayers. In his view, Mountain Fuel's plan favors shareholders at ratepayers' expense. He asserted that the plan's use of a net income "trigger" to govern award payout is a particular source of the imbalance. He testified that the plan does not, but should, reward

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allocated to Mountain Fuel from Questar Corporation and Questar Service Corporation; (2) Mountain Fuel's Annual Management Incentive Plan (AMIP, for managers); and (3) Mountain Fuel's Performance Incentive for Employees (PIE, for other employees). They will be referred to collectively as the "plan".

employees solely for goal accomplishments due to employee actions, instead of improperly including those which occur as a result of weather sensitive sales, regulatory decisions, or actions contrary to the interests of ratepayers. He proposed these considerations as standards the Commission should use to judge the amount of expense recoverable in rates. Ms. Cleveland, witness for the Committee, advanced a similar case. Mountain Fuel's Glenn Robinson testified that the plan, as the Company intends to implement it in the test year, meets these regulatory concerns.

The testimony of the Division and the Committee focuses first on proper plan design and second on recovery of expenses. The Company tends to parry the question of design by asserting that as the plan will be implemented in the test year it will meet the Division's proposed standards. In our judgment, plan design is the issue that must govern our determination of allowable expense.

We will be guided by the uncontested fact that any amount permitted in rates but not paid to employees for meeting goals will go, other things being equal, to shareholders. We find that the plan as currently designed makes this unacceptable outcome likely. Furthermore, since the purpose of the Company's plan is to motivate behavior yielding above-normal results, Mr. Mecham argued that above-normal earnings should be the source of the bulk of compensation expense. Otherwise, he asserted, incentive compensation is simply a wage and salary increase.

A third consideration also touches on the purpose of the plan, which is to promote performance exceeding normal expectations. The Division argued that this may place incentive compensation outside the bounds of normal rate treatment as not known or measurable, and not normal and recurring. The Division argued that the incentive payout for 1993 is not known and measurable because the last three months of the year are not in the test year and will affect payout, in part because of weather variations. In standard ratemaking, such an expense would not be eligible for recovery in rates. The Committee independently reached these same conclusions.

(1) Plan Design

The contested issues of plan design are, first, goals, second, whether outcomes not solely tied to the employee's own actions should be the basis for awards, and third, the net income "trigger."

Mountain Fuel has two financial and three operating goals in its incentive compensation plan. These are the net income, rate of return on equity, customer service, customers-per-employee (productivity), and temperature-normalized distribution non-gas revenues (sales) goals.

The net income goal of $23.5 million can be reached by both higher than expected sales and lower than expected expenses. Mr. Mecham agreed that both shareholders and ratepayers benefit from expense reductions, but noted that attainment of the goal is most affected by weather and other factors not within employee control. Mr. Robinson argued that financial goals promote performance resulting in a smaller revenue deficiency in this docket, and are therefore in the ratepayers' interest. Incentive compensation expenses for Questar financial performance also should be allowed, he asserted, because a strong parent company can raise equity capital on favorable terms, a ratepayer benefit. Mr. Mecham stated that no concrete evidence had been offered in support of these propositions. Because expense reduction is a benefit, he recommended allowance of only 50 percent of the payouts associated with this goal. Under cross-examination, he agreed with the Committee that 100 percent should be disallowed, because the Commission had previously disallowed recovery for financial goals, absent a definite showing of ratepayer benefit.

The Division and the Committee recommended complete disallowance of expenses associated with the rate of return on equity goal. Where customers are captive, the Division testified, it is unacceptable to deliberately reward employees with ratepayers' money to exceed allowed return unless ratepayer benefit is clear. Achievement of the goal also depends on weather variation. The Company argued that the goal is to spur improvements in efficiency by removing increased investment as a source of goal attainment.

Our policy has been to disallow recovery of expenses associated with financial goals where no credible link to ratepayer benefit is established. There is no apparent disagreement with this policy. Witnesses have quoted it in testimony and have agreed that the plan should benefit both ratepayers and shareholders. Therefore, the question is whether Mountain Fuel has established this link. We agree with the Division and the Committee that it has not done so. The record contains subjective assertion, not quantitative demonstration. We have consistently rejected this and will do so again here. We find that incentive compensation expense associated with the attainment of purely financial goals should not be recovered in rates.

One operating goal, the sales goal intended to increase weather-normalized firm sales, is disputed by the Committee. According to Ms. Cleveland, the goal is load building; it disregards efficiency, conservation and demand-side options. She noted that load-building programs have been prohibited by the Commission in Docket Nos. 6668 and 6791. In the Company's view, increasing sales can benefit ratepayers by spreading fixed costs over more units of sales. Without a more successful showing of ratepayer benefit, we will not alter existing policy. We therefore find that no plan expenses associated with meeting this goal should be allowed in rates in this docket.

The two remaining goals are customer service, measured by surveys of customer satisfaction, and productivity, measured by the number of customers per employee. The Committee argued that in a proper plan these goals would be linked so that both must be attained before payout for either occurs. The reason is that otherwise, customer service could be sacrificed to achieve short-term gains in efficiency. While not advocating disallowance of payout expense, Mr. Mecham expressed disapproval of the Company's failure to link the goals in this way. The Committee also pointed out that in 1992 the customer service goal could only be achieved if 90 percent of those surveyed reported good or excellent service. This was decreased to 87.5 percent for 1993, an amount just .8 percent above the results of the prior survey. The Committee testified that this goal is improperly formulated. By contrast, in 1992, the productivity goal was 359 customers per employee; in 1993, 361. In 1992, the productivity goal was attained but the customer service goal was not. The Company's response to these arguments is that it expects to meet both goals during the test year. We do not find this sufficient. We regard customer service as an important, even central, plan design consideration. It is not enough simply to forecast that both goals will be attained in the test year. Linking the two goals as suggested here is a sensible precaution. We see no credible objection, even by the Company, and therefore find that in an acceptable plan the two goals should be linked as recommended by the Committee.

Accountability, responsibility, and motivating employees to pursue goals should guide incentive compensation. Rewarding employees for factors like weather changes reduces incentive compensation to something akin to a general wage or salary increase, as the Division pointed out. To be acceptable for ratemaking purposes, we find that an incentive plan should be based on employee performance alone.

Under the plan, no payout for goal achievement can occur unless the income trigger of $21.6 million is first met. Reaching this figure can be affected by weather, changes in business conditions, and other factors which are beyond the control of employees. We have just found employee actions to be the only relevant factor. But beyond this, we find that the income trigger skews the plan toward the attainment of the financial goals we have rejected. No operating goal payout can be made without first meeting the income trigger, but it appears the return on equity goal could be attained first. In the Division's opinion, the trigger concept makes difficult an assessment of the reasons for payouts, as well as the amounts, by mixing, or "intertwining" goals. We therefore do not approve of an incentive compensation plan which conditions compensation for attainment of the goals we deem important, productivity and customer service, on achieving a level of net income first. The trigger will have the effect of motivating employees toward increasing shareholder value first, and ratepayer satisfaction second. During final argument, Mountain Fuel agreed to eliminate the trigger.

(2) Allowable Expense

The Division argued that no incentive compensation plan expense should be recovered in rates because the plan should be funded from the results of above-normal performance. The Committee also argued that the expense should be eliminated. Mr. Mecham, however, would allow $643,522 to be recovered in this docket if the plan were to be redesigned to meet the Division's recommended standards. We agree with these standards and have been guided by them to reach our decisions on goals, actions beyond the control of employees, and income trigger.

Several factors underlie the Division's $643,522 recommendation. First is the matter of appropriate goals and the expense associated with them. Second, Mr. Mecham stated that the Company's method of accounting for the expenses of the plan in the test year, involving estimation and accrual, is a hybrid cash and accrual method, and is in certain respects inconsistent with Commission-allowed practices. Though actual incentive plan compensation costs for 1992 were paid to employees in February 1993, costs for 1993 are estimated and accrued, becoming part of the compensation plan expense in the test year. Thus, according to Mr. Mecham, events outside of the test year could materially affect actual payout under the plan. Therefore he recommended using 25 percent of actual 1992 expenses and 75 percent of the accrued 1993 expenses as an adjustment to incentive compensation expenses.

Mountain Fuel agreed that this is a reasonable way to arrive at test-year expenses for the plan. There being good reason for it and no objection to it, we find that the Division's recommended approach should be used in this docket. Any allowable test-year expenses will be calculated accordingly.

Third, the Company increased the payout amount by approximately 17 percent to account for overheads. These include FICA, unemployment insurance, workmen's compensation, general public liability insurance, pension plan, and stock plan. Mr. Mecham argued that, of these, only the first three, totalling 8.5 percent, are required by federal and state law, and are therefore a warranted addition to base pay. The last three are discretionary and should be rejected. Fourth, he testified that Mountain Fuel erred by calculating the plan expense based on total base pay, a sum which includes the pay of short-term employees who are not eligible for the plan. The associated expense should be eliminated, he stated. We find that these proposed modifications are reasonable and will adopt them for the purposes of this adjustment.

Mr. Robinson recalculated Mr. Mecham's $643,522 figure to "correct mistakes." This produced $1,686,447 as the amount the Company argued should be allowed if the Commission finds completely in the Division's favor. But, Mr. Robinson asserted, Mr. Mecham had also failed to reflect the fact that test-year accruals are only for operating goals, in the amount of $1,800,000, including overheads.

Thus, the Company argued, when all required factors are correctly accounted for, its initially filed amount of $2,109,420 should only be reduced to account for the acceptance of the 1/4-3/4 cash-accrual method of accounting for the expense in the test year, making the amount requested $1,938,123.

Mr. Mecham disagreed with this recalculation. With respect to payroll overheads and the use of a revised total base-pay figure, two factors which Mr. Robinson testified explain some of the difference between the $643,522 and the $1,686,447, we agree with Mr. Mecham. We are unable to reconcile the remaining difference.

To summarize, our policy has been to allow recovery of expenses if ratepayer benefit is demonstrated, and is not merely conjectural. We reaffirm this policy here and disallow expenses for financial goals and the net income trigger. We also eliminate the expenses of the load-building sales goal, because net ratepayer benefit has not been shown. We authorize recovery of payouts only for results achieved by employee efforts, and we disallow anything for the influence of extraneous factors like weather. To these alterations in plan design, we add that the recoverable expense must depend on the applicable portion of total base pay only. We permit an adjustment for overhead of 8.5 percent. Collectively, these decisions reduce the ratepayers' share of plan expenses.

The argument is correct that the plan could be funded, legitimately and completely, from the above average earnings it is designed to produce. On this basis, we could disallow the expense. But we have suggested changes to alter the plan to reflect ratepayers' perspective, and we believe it is better public policy to recognize that ratepayers have a direct interest in the performance of utility employees. A more effective utility is beneficial to ratepayers, and incentive compensation is a good way to motivate superior performance. To reject all plan expense could be interpreted as a denial of this unobjectionable premise and a shirking of regulatory responsibility. We therefore conclude that some plan expense should be recoverable in rates. By carefully limiting the amount, we are attempting to balance with the notion of ratepayer benefit the argument that allowing the expense may violate the long-standing regulatory rule allowing recovery only of normal and recurring expense. In this way too, we resist the potentially inequitable outcome that shareholders benefit by the amount of plan expense in rates when employees are not compensated because goals have not been attained.

We cannot determine the dollar amount of allowable expense precisely corresponding to our decisions. The record is replete with party differences, which, given the particular time demands of this docket, we are unable to resolve. As an example, witness Mecham testified that he had been unable to unravel goal-specific payouts. Nevertheless, we are satisfied that precision is unnecessary. What is important is an amount which follows from the rationale for our decisions. That could be zero or a positive amount, but far less than the Company has requested.

The Company is accruing $1,800,000 for the 1993 expense of the three operating goals it expects will be attained. But we permit recovery only for the productivity and the customer service goals. Our other decisions also reduce the amount. The Division has testified that about $640,000 is the amount for a plan meeting its proposed standards. We have adopted these standards but have rejected its recommendation to allow 50 percent of the expenses of the net income goal. On the whole, therefore, the Division's figure is too high, particularly because we intend ratepayers' exposure to be limited should the two goals not be met. Complete disallowance is unacceptable. We conclude that a reasonable amount of recoverable plan expense is closest to that advocated by the Division, and will allow $600,000.

b. 1992 Incentive Plan Overhead

All parties agreed that labor costs should be reduced by $208,913 to account for 1992 incentive plan overhead. We accept this adjustment.

c. Phantom Stock

"Phantom stock" is a deferred compensation program for officers and directors begun in February 1992, as an amendment to the Questar Corporation Annual Management Incentive Plan. It involves crediting the value of Questar Corporation common stock to an employee's account at market price. Thereafter, a quarterly comparison of that price to current market price is made and the difference booked to Account 9300, Miscellaneous and General Expense, as the outstanding liability for this "phantom" stock. In this way, phantom stock measures the value of deferred compensation. Because share price rose an extraordinary amount during the test year, the appreciation adjustment proposed by Mountain Fuel is large.

Financial accounting standards require Mountain Fuel to accrue an expense for phantom stock appreciation, according to its witness, Glenn Robinson. The proposed test-year expense is $498,866. Division witness Huntsman and Committee witness Cleveland gave four reasons why the expense should not be allowed. First, the program unnecessarily and unfairly forces ratepayers to bear the risk of stock price appreciation. According to the Division, the Company could and should have selected a stock option program which did not place ratepayers at risk. Second, the proposed expense is not known and measurable, and may not be normal and recurring. Third, the Committee noted that the expenses associated with programs having financial goals, or that reward employees for financial performance, as this one does, have been disallowed by the Commission in prior cases. Finally, the Division and the Committee testified that financial accounting standards may require the Company to book the expense, but cannot dictate regulatory treatment of it.

Though disallowance was their recommendation, at minimum, the Division and the Committee stated, the expense should be normalized to eliminate the effects of abnormal stock price appreciation.

If the phantom stock program were acceptable in concept, the abnormal stock price appreciation recounted on this record would suggest a need to normalize the test-year expense. Otherwise, because of an abnormality, and for the most part regardless of subsequent stock price behavior, rates would be too high for as long as they remained in effect.

But we find this new compensation program unacceptable. First, our policy is that ratepayers will not bear the expense of employee incentive compensation for attainment of financial goals unless ratepayers are shown to benefit from it. Mountain Fuel justifies the proposed phantom stock deferred compensation expense as part of the competitive compensation package required to retain and motivate management. Ratepayers, who are expected to bear the costs of the program, are said by Mountain Fuel to benefit from "management continuity." Despite a certain surface plausibility, this is not convincing. While it is clear ratepayers bear costs and risks, it is unclear that benefit is proportionate. The burden to demonstrate this benefit is Mountain Fuel's alone. It cannot do so by mere assertion. We require a basis for determining the reasonableness of the expense, such as the comparison of alternative forms of deferred compensation suggested by the Division. Second, though a variation of the first point, we find the phantom stock program unreasonable because ratepayers disproportionately bear its risks. We accept the Division's undisputed argument that other stock option approaches would treat risk more fairly. Thus, we conclude that the program's expense of $498,866 may not be recovered in rates in this docket.

d. Questar AMIP

Mountain Fuel proposed recovery of $235,182 allocated to it, using the Distrigas formula, for Questar Corporation's Annual Management Incentive Plan. This Plan rewards officers and key employees for attainment of Questar Corporation financial goals. It is not independent of factors beyond employee control, such as weather. After due consideration, we disallowed such expense in item II.D.4.a., Incentive Compensation. No new argument or issues are raised here. Consistent with our previous decision, we will not permit recovery of the proposed $235,182.

e. Celsius ECIP Bonus

All parties agreed that labor costs should be reduced by $472 to account for the Celsius ECIP bonus. We accept this adjustment.

5. Retirement Issues

The Committee recommended that the costs of Mountain Fuel's and Questar's Executive Incentive Retirement Plans and the Supplemental Executive Retirement be removed from test year expenses.

The Committee maintained that Mountain Fuel and Questar already provide a generous pension plan and that ratepayers should not fund additional executive benefits that are provided to a select group of employees. In addition, the Committee contended that the Internal Revenue Code disallows these expenses as a tax deduction because Congress has determined the costs of supplemental retirement programs to be excessive. The Committee argued that the Commission should decide similarly.

Expenses for Mountain Fuel's programs totaled $63,235, and Questar's allocation to Mountain Fuel for them totaled $52,216. The supplemental retirement expenses paid to one retiring executive amounted to $16,296. According to the Committee, the Company failed to adequately explain why one retired officer should receive a benefit not paid to other early retiring employees; hence, the expense should not be borne by ratepayers.

The Company testified that these expenses were indeed tax deductible, countering the Committee's main rationale for a disallowance. The Division testified that its investigation also showed the expenses to be tax deductible. The Company insisted that the programs are necessary to attract and retain qualified executives, and asserted that the costs are minor. The Company objected to the Committee's characterization of the Supplemental Retirement expense stating that the expense was incurred at a time of a major functional consolidation that significantly reduced costs.

We find the evidence supports that these expenses are tax deductible and are legitimate expenses to be recovered in rates. They should not be excessive, however, and we find that they are not. Therefore, they will be allowed as test-year expenses.

6. Advertising Issues

Mountain Fuel requested recovery of $1,309,704 in advertising expenses. This is an increase of $640,508 over the amount requested in its 1989 rate case, and is $949,530 more than is currently allowed in rates. In the previous rate case, only $360,174 of advertising expenditures, all classified as informational or institutional (financial), were recognized for cost recovery. We did not allow cost recovery in that docket for promotional advertising.

Rule R746-406 states:

> no electric or gas utility may recover from a person other than shareholders or other owners of such utility any direct or indirect expenditures by such utility for political, promotional or institutional advertising.

Exceptions are permitted for:

> advertising which informs consumers how they can conserve energy, use energy wisely, or reduce peak demand for energy; advertising required by law or regulation; advertising regarding service interruption, safety measures, or emergency

> conditions; or advertising concerning employment opportunities with such utility; or any explanation of existing or proposed rate schedules, or notifications of hearings thereon; or information about the availability of energy assistance programs. Barring such explicitly stated exceptions, the cost recovery of any promotional or institutional advertising by ratepayers would have to be found by the Commission, after due consideration, in either a rate case or separate proceeding prior to implementation to be in the public interest.

Mountain Fuel contended that there are three types of advertising defined in the Commission rules that are relevant to these proceedings. These are institutional, promotional and informational advertising. While informational advertising is typically deemed beneficial to ratepayers and expenses for it therefore allowed in rates, we must explicitly find that institutional and promotional advertising are in the public interest before permitting cost recovery. The Company argued that much of its promotional advertising is in the public interest, and that its financial, a form of institutional, advertising, and its "public interest" advertising should be considered for cost recovery.

a. Institutional Advertising

Mountain Fuel's institutional advertising expense is $48,325. It consists of an allocated portion of Questar Corporation's institutional advertisement. The Company did not request recovery of these expenditures, and all parties agreed that they are not eligible. The Committee also requested removal of Questar Service Corporation's allocation to Mountain Fuel of $4,352 of institutional advertising. The Company objected, and maintained that this allocation is a normal component of business cost. The Company charged that the Committee had engaged in "microscopic inspection" of these charges just because they are from an affiliate.

We find that institutional advertising is designed to increase goodwill, a shareholder benefit, and by Rule R746-406 should be funded by shareholders unless shown to be in the public interest. The record is devoid of such a showing. Therefore, we will not allow the expenditures to be recovered in rates. We find that the Committee's proposed affiliate adjustment for institutional advertising is reasonable and will accept it. We explicitly reject the Company's objection to the Committee's inspection of affiliate charges. To the contrary, given our often repeated concern about affiliate charges, we encourage parties to examine them closely.

b. Financial Advertising

The Company considers financial advertising a necessary cost of attracting capital that should be allowed in rates. This $37,691 expense was not contested by any party. Although financial advertising is not explicitly referred to in our rules, we find that such expenditures, in modest amount, could lower the cost of attracting capital and would thereby be in the public interest. We conclude that this expense should be recovered in rates.

c. Promotional Advertising

The promotional advertising category is controversial. The Company's promotional advertising is divided among its realtor/builder campaign, its Kern River corridor dealer co-op program, and its appliance/distributor co-op program. The Company claimed an expense of $478,337 for these programs.

The Company argued that these advertising campaigns are in the public interest, and deserve cost recovery, because promotional advertising, by increasing sales, will lower the cost of gas for the average consumer. Fixed costs will be spread over a greater volume of sales thus lowering the average cost of gas. The Company advised the Commission to disregard Case Nos. 6668 and 6791, which the Committee had cited, because they explicitly disallow promotional advertising. The Company contended that these past decisions were rendered in an era of perceived natural gas shortage and thus are not relevant to conditions today.

The Committee argued that the Company's promotional advertising is intended to build load by increasing natural gas appliance saturation. The Committee presented evidence that advertising is not needed to establish markets for gas appliances and cited Commission orders in Case Nos. 6668 and 6791 as support for their position.

The Division requested disallowance of all promotional advertising expenses based on the argument that the Company failed to provide adequate information to qualify for the public-interest exception of Rule R746-406. According to the Division, the Company also failed to prove that such advertising increases revenues enough to cover the associated expense. In addition, the Division expressed concern that promotional advertising could lead other utilities to request cost recovery for promotional advertising, resulting in an advertising war funded by ratepayers.

We find the Division's and the Committee's arguments persuasive. We find that the Company has failed to provide evidence showing a correlation, much less a causative relationship, between promotional advertising expenditures and increased sales. Nor has it provided other evidence of public interest. We conclude that such expenditures do not qualify as an exception to our rule prohibiting recovery and therefore should be disallowed.

d. Public Interest Advertising

The Company argued that its self-described "public interest advertising," which includes the Light a Better Fire Campaign, the "Project Environment" sponsorship, and the Natural Gas Vehicle campaign, has the dominant theme of improving air quality or advancing environmental and conservation themes. The total cost of this advertising is $475,662. Although acknowledging that aspects of this advertising are promotional, the Company contended that the public interest aspect qualifies it for cost recovery. The Company argued that the Commission should consider two points. First, consumers should be informed of, and thus be able to choose, natural gas for both economic and environmental reasons. Second, unless these advertising expenses are recovered in rates the Company could be disadvantaged in its competition with other unregulated, and perhaps environmentally unsound, energy alternatives. The Company stressed that the Commission should give proper weight to promotion of conservation and the dissemination of beneficial information as aspects of the public interest. The Company claimed these advertisements promote energy efficient appliances and are designed to reduce peak requirements in order to improve load factor. Thus, they are asserted to be in the public interest.

The Committee testified that these advertisements are promotional in that they encourage the purchase of gas appliances and natural gas vehicles. The Committee contended that advertisements that promote clean air should be regarded in the same light as charitable contributions, and thus funded by shareholders even if socially beneficial. Further, the Committee maintained that the promotion of natural gas vehicles is not a cost-effective means of increasing the Company's load factor, and asserted that the "Build a Better Fire" campaign only increases the winter peak, thereby exacerbating the Company's low load factor problem. The Committee argued that there is a lack of evidence showing that ratepayers benefit from these expenditures, and contended that funds could be better spent on demand-side measures to reduce winter peak. The Division agreed with the Committee's proposed adjustment.

We find that the "Light a Better Fire" campaign is clearly promotional and while there is some environmental benefit associated with the use of gas fireplaces, as opposed to wood or coal, there is also a detriment relative to using the same gas in an efficient gas furnace. These advertising expenses will not be allowed in rates. The Project Environment Campaign is akin to a charitable contribution and should therefore be funded by shareholders.

We found in Docket No. 92-057-04 that the natural gas vehicle program could benefit ratepayers by increasing demand in the low usage months, leveling yearly load and raising load factor, thus promoting lower rates. We also found that the program has air quality benefits. But the campaign is also clearly promotional and the Company, as directed in our July 2, 1992 Order in that docket, did not provide adequate evidence that benefits will accrue to all customers through increased throughput and higher system load factors. However, on balance, because of the public benefit of this program, we find that $100,000 should be recovered in rates. In the future we will expect the Company to recover these costs in the rates for natural gas vehicles. Further, only reasonable costs will be allowed.

e. Informational Advertising

The Company's informational advertising includes the Blue Stakes Campaign, the Equal Payment Plan, the Fall Furnace Preparation, the Consumer Segment, the Trade Ally advertising campaign and the Appliance Efficiency Program. The parties are in agreement that informational advertising, except for the Appliance Efficiency Program, should be included in the cost of service. The Company maintained that this latter program informs customers of the energy consumption, quality and performance standards of high-efficiency natural gas appliances, promotes conservation and wise energy use, and thus meets the criteria for inclusion in rates. The Committee argued that this program is part of the Company's co-op program of shared costs. Instead of being geared to promote higher levels of energy efficiency, it is intended to expand the natural gas market and should be disallowed. The Division agreed that the program is intended to encourage the selection and installation of appliances designed to use the utility's service, and should be disallowed.

We find that these campaigns, with the exception of the appliance efficiency program, are informational and not promotional. Recovery of expenses in rates will be allowed. The Company's appliance efficiency program, which is advertised through the co-op program, totals $107,355 of expense. We find this program predominately promotional, but with an important informational aspect.

We do not intend to discourage the Company from undertaking informational advertising which genuinely informs the public about energy conservation and efficiency. But we must distinguish this from load-building advertising, which we cannot justify as being in the public interest. We will view advertising to promote energy efficiency and demand-side resources differently than that which promotes one energy source for appliances over another.

There is no criterion or formula which we can apply to the Company's appliance efficiency costs to arrive at less than 100 percent disallowance. We intend to permit recovery of a small portion of this advertising because we find public benefit in it. Increasing appliance efficiency is important and we support it. In order to encourage the Company to address efficiency more directly, and less in the context of promotion, we will permit recovery of ten percent of the appliance efficiency advertising expense. Further analysis of this issue should take place in the context of the Company's Integrated Resource Planning process for demand-side measures.

f. Parade of Homes and Miscellaneous Advertising

The Committee recommended that expenditures for the Parade of Homes, $191,312, and for miscellaneous advertising, $8,481, be disallowed. The Company testified that Parade of Home expenditures were incurred to educate the public about efficient use of natural gas in new homes. The Company maintained that this qualifies as a public interest expense because it is a cost-effective way to inform the general public about energy efficient gas homes. The Committee argued that this program is not an effective way to disseminate information about energy efficient gas appliances and that its primary purpose is to encourage the consumption of natural gas. The Division agreed with the Committee's position. We find that the Parade of Homes expenditures are promotional and will not be allowed in rates.

Miscellaneous advertising includes national advertisements to attract new industrial and commercial customers to Utah of $7,235 and expenditures of $1,246 for Mountain Fuel's lobby displays. The Company argued that the national advertisements should be considered economic development expenses that are in the public interest. Lobby displays, it contended, are normal and customary in business. The Committee argued that both expenditures are promotional in nature and should be disallowed. We find that the national advertising may be considered Company-sponsored industrial promotion to enhance the state's economic base, is reasonable in magnitude, is in the public interest, and therefore qualifies for recovery in rates. The lobby displays lack this public interest characteristic, however, and expenses for them are not recoverable.

7. Dues and Donations

a. American Gas Association (AGA) Dues

Mountain Fuel paid about $300,000 to the AGA for dues during the test year. The Committee contended that a portion of these dues were used to fund activities the Commission would disallow if the Company paid for them directly. The Committee used a 1992 National Association of Regulatory Utility Commissioners' Oversight Committee audit of AGA expenditures to derive its proposed adjustment to disallow expenditures for media communications, community and consumer affairs, and government relations. This proposed adjustment would reduce test-year expenses by $190,158. The Division agreed that activities that would be disallowed by the Commission if funded directly by Mountain Fuel should receive that same treatment if funded by a third party through dues. The Company presented evidence that only

9 percent of AGA dues are used for promotional advertisement. Likewise, approximately one percent of these dues were for lobbying.

We find that ratepayers should not support third-party funding of activities that we have previously excluded from recovery in rates. We will, however, accept the unrebutted testimony of the Company regarding the percentage of AGA dues devoted to activities that we disallow. This amounts to a decrease in the dues expense of $31,693.

b. Questar Dues and Donations Allocated to Mountain Fuel through Questar Service Corporation

Questar Corporation pays dues to various organizations and allocates these costs to its affiliates. We have determined that most of the costs allocated to Mountain Fuel are not eligible for recovery in rates. The Committee and the Division recommended that these dues should not flow to Mountain Fuel through affiliate charges where the dues support organizations for which Mountain Fuel itself would not be allowed recovery. The Committee and the Division did not recommend adjustment to the affiliate charges of Questar Pipeline and Wexpro, because these affiliates are monitored or controlled by either the FERC or the Wexpro Agreement. The Company did not contest these proposed adjustments. The Committee calculated an adjustment of $19,484 by using the actual expenditures made during the test year, and determined the percentage of total Questar Corporation expenditures that were disallowed and the portion that was allocated to Mountain Fuel by Questar Service Corporation. The Division calculated the adjustment at $34,772 by a different procedure, using data that approximated test year expenditures. The Division did not update its calculations. The Company agreed with the Committee's estimate of the amount of the adjustment.

We find that donations, dues, lobbying expenses and political contributions that are disallowed for cost recovery when directly funded by Mountain Fuel are not recoverable when included in affiliate charges. The amount that will be disallowed recovery is $19,484.

c. Miscellaneous and Economic Development

Mountain Fuel donated to causes and paid dues to associations, for which it requested recovery, including Ballet West, Miss Tooele County, Late Night Basketball, and Junior Achievement. The Committee maintained that it is inappropriate to ask ratepayers to fund the Company's charitable contributions. The Division agreed.

Although we might personally agree with many of the charitable contributions made by the Company, we find that we cannot require ratepayers to fund them. Therefore, we disallow the proposed expense of $21,650.

The Committee also recommended that dues and donations to organizations that the Company claimed promote economic development should be disallowed. Examples include dues or donations to the Utah Foundation, the American Economic Development Conference, and the Economic Development Corporation of Utah. The Company maintained that these expenses, incurred to promote economic development, benefit the citizens of Utah and are therefore in the public interest. In support of its position, the Company cited the recommendations of an Economic Development Task Force established by our January 8, 1992 Order in Docket No. 90-035-06. While these recommendations have not been adopted in any formal way, they do express a concern for the role of utilities in economic development.

We favor responsible efforts to promote economic development, and find acceptable reasonable amounts of direct utility involvement. We have found direct utility involvement acceptable when auditable, verifiable, and in reasonable amounts. Our reservations about the third-party approach stem in part from our inability to audit the activities of such organizations and to gauge effects on the public interest. Therefore, we find that all dues and donations to third-party organizations will not be eligible for recovery in rates unless the Company can provide convincing evidence that such expenditures are directly beneficial to ratepayers. The burden to demonstrate this rests with the

Company and we find that it didn't meet its burden. It is not up to the parties to disprove a Company assertion. We conclude that these findings are consistent with the recommendation of the Economic Development Task Force.

We will consider for cost recovery a reasonable amount of direct Company expenditures for economic development activity if such expenditures promote efficient use of natural gas and neither promote the use of natural gas in lieu of other forms of energy nor favor one jurisdiction over another. We believe that the Company's best contribution to economic development is the provision of high quality, reliable natural gas service at the lowest possible rates.

d. Taxpayer Association Dues

The Company paid $5,612 in dues to Utah and Wyoming taxpayer associations and asserted that the educational services received by Mountain Fuel's employees benefit ratepayers. Furthermore, these associations provide valuable tax information to the public in general. The Committee testified that these associations are overtly political lobbying organizations that promote tax law changes to benefit its constituency and thus do not deserve to be funded by ratepayers.

We find that the Committee's arguments are persuasive. There is insufficient evidence that these dues benefit ratepayer interests, and therefore they will not be recovered in rates.

8. Affiliates' Rate of Return

Services received by Mountain Fuel from affiliates are billed as required by Questar Corporation's "Intercompany Billing Policy" at cost of service, including rate of return. Billings were received from Questar Corporation and Questar Service Corporation. The return component for the test year was 13 percent, which was adjusted by Mountain Fuel to its requested rate of return of 12.1 percent.

Both the Division and the Committee proposed adjustments to bring the rate of return to their respective recommendations of 11.0 percent and 10.8 percent. On rebuttal, Mountain Fuel witness Glenn Robinson argued that 13 percent is reasonable and appeared to dispute any proposed adjustment even though one had already been incorporated into the testimony of another of its witnesses, Gary L. Robinson. In the final analysis, the Company did not challenge the adjustment.

Our policy, stated in our Order in the prior rate case, 89-057-15, and elsewhere, is that affiliate billings should not include a rate of return greater than we authorize for the utility. Otherwise, transactions with affiliates would be a means of increasing return beyond that allowed, and ratepayers, other things being equal, would pay more for utility service than we have found just and reasonable. We have consistently ordered revisions where necessary to reduce the rate of return component of affiliate billings to that authorized for the utility. Parties differ only as a result of their rate of return proposals, which are not the same.

We conclude that 11.0 percent, the rate of return on equity found reasonable in this docket, is appropriate for calculating the affiliate billing expense to be recovered in rates. This reduces test-year expenses by $139,607.

9. Other Disputed Issues

a. Allowance for Uncollectibles

The Company accrues an allowance for uncollectible accounts and has used a rate of .5 percent of General Service sales as an approximation of bad debt. The Committee claimed that the Company has historically over-accrued this bad debt allowance. The actual write-off, as a percent of the allowance accrual, has ranged from 54 percent to 73 percent from 1987 to 1991, and this has led to a substantial overage in the Company's allowance account. The Committee advocated a .35 percent accrual rate to better reflect write-offs in the rate-effective period. The Committee also recommended this reduced rate to account for an alleged failure by Mountain Fuel to strictly follow its own deposit policy. The Committee maintained that this failure could have had the effect of encouraging some ratepayers not to pay their bills, thus increasing bad debt expense.

The Company and the Division advocated a .36 percent accrual rate which they contended reflected actual write-offs during the test period. The Company reduced uncollectible accounts for 1992 by $500,000 to reflect past over-accrual. The Company termed the Committee's proposed adjustment for failure to strictly follow policy "punitive" and stated that it had become aware of the problem through an internal audit and had already taken steps to address it.

We find that the actual write-off expense for this test period should be used as the accrual rate for the rate-effective period. We will not accept the Committee's proposed adjustment of the accrual rate for the Company's failure to strictly follow its deposit policy. We regard internal audits as a means to reveal errors in Company procedures.

b. Delta Center

The Committee recommended that expenses for the Company's use of a Delta Center suite for viewing professional basketball, hockey games, and other entertainment should not be charged to ratepayers. Mountain Fuel sought recovery of $2,782 directly incurred and $33,959 allocated to it by Questar Corporation. The Committee's audit showed that the expense was primarily incurred to entertain homebuilders, appliance dealers, other business clients, and representatives of the Rocky Mountain Gas Association. The Company contended that the expense was in part for employee recognition and in part for business relations, but could not adequately differentiate between these in the amount allocated to it by Questar.

The evidence shows, and we find, that the primary use of the Delta Center suites was for business promotion. We cannot determine the extent to which the suite was used for employee recognition. Business promotion is not an appropriate expense for recovery in rates. Therefore, we conclude that the $36,741 of direct and allocated costs will not be included in test year expenses.

c. Annualization of the Distrigas Allocation Formula

Questar Corporation's general and administrative expenses are allocated to each of its subsidiaries based on the Distrigas Formula. This formula was used by the Commission in Docket No. 89-057-15, the Company's last rate case. The inputs to the formula and the resultant allocation factor is updated annually at the end of the calendar year. The test year combines portions of two calendar years, so the Company derived an allocation factor by using the 1992 allocation factor of 42.97 percent and the 1993 allocation factor of 41.90 percent weighted by the number of months of each year in the test year.

The Committee and the Division advocated annualizing the Distrigas allocation factor using the 1993 figure of 41.9 percent. The Committee asserted that this adjustment is analogous to a price change and thus should be annualized. In rebuttal, the

Company argued that because of weather and corporate restructuring, the allocation factor for the 1994 rate effective period would be higher than either 1992 or 1993. If any annualization were to take place, the Company asserted it should reflect such future conditions. It estimated this allocation factor at 43.09 percent. The Committee, in surrebuttal, pointed out that the corporate change referred to took effect outside the test period. The Division argued that other changes outside the test period could cause the allocation factor to decrease.

We find that the Distrigas formula used for allocating Questar's general administrative costs should be based on an end-of-year calculation which reflects what happened during the entire year. Given that this test year combines portions of two calendar years, there is some appeal to using a weighted average of the two years. However, we are persuaded by the Committee's argument that this adjustment is analogous to the annualization of a price change. Therefore, we find in favor of the Committee's and the Division's recommendation. This adjustment will result in a decrease in test year expenses of $37,623.

d. Company Aircraft

The Company used Questar Corporation's aircraft during the test year for employee travel, for which it was charged both a "fixed" and a variable charge. The Company requested rate recovery for both expenses. The Division and the Committee argued that the

Company's decision to use the corporate airplane instead of commercial flights resulted in inflated costs for air travel. The Division recommended an adjustment of $188,000, while the Committee calculated an adjustment of $212,809.

Mountain Fuel compared the variable cost of using the corporate jet with commercial airfare and on that basis determined that the corporate jet was less expensive than commercial airfare. The Company procedure includes the costs of meals and overnight expenses associated with commercial flights, if these additional costs are incurred. The Division and the Committee contended that it is improper to ignore the "fixed" charge component of the corporate jet use. The fixed charge is based on Mountain Fuel's previous year's hourly use of the jet as a percentage of the total hours used by all affiliates. According to the Division and the Committee, ignoring the current year use effect on the following year's "fixed" charges underestimates the true cost of the corporate jet's use. In addition, the Division alleged that the Company violated its own decision-making criterion on at least two occasions where the cost of commercial flights was substantially less than the variable costs of the corporate jet.

The Company testified that it is appropriate to consider only the variable cost for each decision because the fixed costs would be incurred whether the airplane was used or not. The Company's exhibit No. 1.11R shows a net savings of $4,729 in variable costs using the corporate jet rather than commercial flights. In addition, the Company testified that employees can gain as much as a half a day in travel time per trip using the corporate aircraft, thus improving employee productivity. The emergency response capability of the corporate jet was also used to justify the expense.

We find the Company's decision-making procedure inadequate. Its time horizon for determining fixed costs is too short. When viewed over a longer term, we believe the "fixed" charge is actually variable and therefore should be included in the Company's calculation. Our analysis of MFS Exhibit 1.11R and CCS Exhibit 4.27 shows that the total cost of air travel using the corporate jet was approximately five times that of commercial flights. We find this excessive. Nevertheless, we will not exclude the entire fixed cost from cost recovery. There are savings associated with the use of the corporate jet arising from lower travel times, convenience, and avoidance of additional hotel and per diem expenses. The Company, however, did not quantify them. Therefore, we grant one-half of the Division's $184,000 fixed cost adjustment and also find that the Division's $4,000 adjustment for two excessively costly trips is warranted. The total adjustment to aircraft expenses is $96,000. Future requests for recovery of corporate aircraft expense must include an analysis of "fixed" costs as well as better quantification of the saving of time and travel expense.

10. Demand-Side Management Depreciation Expense

In Docket No. 92-057-08, the Commission approved four demand-side management pilot programs for Mountain Fuel. The order approved the placement of incentive costs and their carrying charges in rate base with the balance amortized over five years. The Company recommended that the depreciation expense be increased by $14,794 to cover the amortization of incentive costs.

We find that these adjustments, which are not in dispute by any party to this docket, are reasonable and test-year expenses will be adjusted accordingly.

11. Other Undisputed Issues

A few adjustments to operating expenses were undisputed by the parties. These adjustments include insurance profit sharing, the Warranty system, a business golf tournament and depreciation of investments in demand-side management.

The Committee recommended that test-year expenses be increased by $27,995 to reflect an adjustment to an insurance policy profit-sharing credit. This credit results from Mountain Fuel's low number of claims during 1990 and 1991 and the fact that it renewed these insurance polices. The credits were recorded on Mountain Fuel's 1992 books. The Committee used an ad hoc normalization procedure to estimate credits that would occur during the test year. The Committee also testified that it is inappropriate for Mountain Fuel's ratepayers to bear the expenses associated with a Questar-sponsored golf tournament for its industrial customers which amounted to $942. The Company did not dispute either adjustment.

The Committee also requested an adjustment of expenses totaling $44,792 for Company work on designing a potential new service called the Warranty System. This project analyzed the market potential for offering a warranty service to Mountain Fuel's customers for their gas appliances. The project was dropped in December of 1992 and the accumulated expenses were then booked. The Committee argued that such expenses were inappropriate because the Company had not received prior Commission approval. The Company agreed to the adjustment, but disagreed with the Committee's logic. The Company stated that the expenses were incurred outside the test period.

We find these adjustments are reasonable and test-year expense will be adjusted accordingly.

E. INCOME TAXES

There was no dispute regarding the method for calculating income taxes. All parties' final recommendations were based on a federal income tax rate of 35 percent which became effective January 1, 1993, the fourth month of the test year. All parties included an additional deferred income tax amortization adjustment of $912,000 resulting from the South Georgia amortization adopted in Docket No. 89-057-15. Also all parties have included Section 29 Income Tax Credits in the amount of $4,477,000 related to the production of gas from wells classified as tight sands. This results in an increase of $686,643 to test-year income taxes.

F. DISTRIBUTION NON-GAS REVENUES

1. Weather Normalization

The Company used an average of temperatures observed during the thirty-year period ending 1990 to adjust sales volumes to reflect normal weather. The normalization method used by the Company was accepted by the Commission following a review by the Division, its consultant, and the Committee and its consultant in Docket No. 89-057-15. Using its revenue model based on bill frequency analysis, the Company priced weather-normalized test-year sales volumes at rates effective January 1, 1993, to derive test period distribution non-gas revenues. This revenue model has been effectively used by the Company in prior rate cases. Actual test year distribution non-gas revenues were $159,074,000. The Company calculated weather normalized revenues to be $155,436,000, a decrease of $3,638,000. No party disputed this adjustment.

2. Unbilled Revenues

Both the Division and the Committee proposed adjustments to test year revenue to recognize unbilled revenue. These adjustments correspond to the adjustments made to the deferred income taxes associated with unbilled revenue. As discussed in Section C.3. above, we accept the recommendation of the Division to increase test year revenues by $2,011,000 to phase-in recognition of unbilled revenues and corresponding deferred income taxes.

3. Natural Gas Vehicle (NGV) Billing

The Committee noted that during the test year the Company underbilled independent businesses due to a NGV billing error which was discovered by a Company audit. The Committee proposed that test year revenues be increased by the amount of the billing error, or $166. The Company stated it did not contest this adjustment. The Company also stated that this proposal raised questions about the level of materiality and the signal it sends to the Company about doing internal audits. The Commission will accept this adjustment since it is not contested. We encourage the Division and the Committee to audit carefully, but we do understand the concern about materiality.

4. State Sales Tax

Prior to July 1992, the Company was required to remit state sales tax collections on a quarterly basis. Beginning July 1992, the Company was required to remit sales tax collections on a monthly basis. The Company was also allowed by the state to keep 1.5 percent of the collections as an offset to the additional costs of remitting the collections on a more frequent basis. The Committee proposed that any revenue change authorized by the

Commission should recognize the 1.5 percent of sales tax retained by the Company.

We rejected the Committee adjustment to cash working capital designed to account for the change in the timing of remitting sales taxes to the state. The reasons for the rejection are specific to the lead-lag study (see C.4 above). In this instance, it is appropriate to recognize the change in sales tax retained by the Company resulting from the change in revenue requirement. The amount is a decrease of $314.

5. Interest Rate on Past Due Accounts

The Committee recommended reducing the interest rate charged on past due accounts from the current 18 percent per year to 9.6 percent per year. While not recommending an adjustment, the Committee calculated the effect of lowering the interest rate charged on past due accounts to be a $669,977 decrease in revenues and a $60,500 decrease in uncollectible expenses. The Division recommended lowering the rate to 15 percent per year. The Company recommended retaining the existing rate as the more effective debt-management tool. Salt Lake Cap/Utah Issues recommended reducing the rate to 7 percent per year, the same as the IRS late payment interest rate charge. Public Witness Duke-Rossati indicated that the threat of termination was a significant inducement to pay bills on time.

In view of the substantial reduction in interest rates generally over the last few years, the Commission finds the interest rate charged on past due accounts should be reduced to 12 percent per year. This results in reduction of revenues of $478,555 and the reduction in the uncollectible expense of $43,214.

6. Interest Rate on Customer Deposits

The Committee recommended increasing the interest rate on customer deposits to 9.6 percent per year based on the rationale that it should be the same as the interest rate for past due accounts. Salt Lake Cap/Utah Issues agreed that these two rates should be the same but advocated seven percent per year. The Division advocated six percent per year while the Company recommended nine percent.

The Commission believes that the general decline in all interest rates over the last few years should be reflected in the interest paid on customer deposits. We find a reduction of this rate to six percent per year is reasonable. This reduces test period expenses by $36,658.

G. STIPULATION ON SUPPLIER NON-GAS COSTS

On November 3, 1993, the parties filed a Stipulation intended to resolve all issues related to rate treatment of supplier non-gas cost. Testimony was presented to explain the Stipulation on November 4, 1993, after which we took the matter under advisement. Our review revealed ambiguities which we requested parties to correct. A revised stipulation was filed November 23, 1993. We accepted it from the bench during hearings on December 6, 1993.

FERC Order 636 was issued April 8, 1992. Its effects on supplier non-gas cost and gas commodity cost, and appropriate state regulatory responses, were disputed issues in this proceeding. For the present, the Stipulation resolves these disputes by retaining Account 191 treatment of supplier non-gas costs, including charges for upstream services such as transportation, gathering and storage; determining how the risks of the newly created capacity release program will be shared; encouraging Mountain Fuel, via an incentive approach, to vigorously participate in that program; and reserving other Order 636 effects for study in the Company's Integrated Resource Planning proceedings.

Order 636 causes most of a pipeline's costs to be recovered in demand charges borne by its firm transportation customers. In fact, firm customers will pay a larger share of the pipeline's total cost of service. Because of its low load factor, and its approximately 85 percent share of Questar Pipeline's capacity, Mountain Fuel is particularly vulnerable to this cost shift. But under the new capacity release program, Mountain Fuel can sell firm capacity it is not using, receiving for any such sale not revenue but a credit offsetting some of the demand charge.

Important aspects of this new program will be revealed only through experience. Under terms of the Stipulation, Mountain Fuel will bear substantial risk for underrecovery of costs formerly recovered in Account 191 pass-through proceedings. Actual credits will depend on who is willing to bid to use the released capacity, and at what price. Demand and supply conditions in this developing market are speculative. Even given Mountain Fuel's relationship as an affiliate, the FERC Order makes Questar Pipeline Company a competitor in the capacity release market, further increasing cost recovery risk.

Placing Mountain Fuel at risk for recovery of costs is intended to encourage its effective participation in the capacity release program. This is an unusual response to a highly unusual set of circumstances. The potential demand for released capacity is a matter of speculation. Though there are limits bounding capacity release prices, actual prices cannot reasonably be anticipated. We find the incentive mechanism adopted herein necessary given the uncertainties of this newly created, and therefore unknown market.

The Division and the Committee judged that firm ratepayers would be at risk for an estimated $13 million of costs shifted by Order 636 to the revenue requirement of Mountain Fuel as the principal firm transportation customer of Questar Pipeline Company. The Stipulation reduces this cost-shift exposure, substantially benefitting firm ratepayers, even if the capacity release credits do not reach anticipated levels. In the opinion of the parties it is the best accommodation of Order 636-related costs and risks that could be accomplished in this docket. Our review of the Stipulation and the filed testimony, as well as our understanding of the effects of Order 636, and of the relationship between federal and state regulation, has persuaded us that this is correct. We therefore conclude that the Stipulation is in the public interest and should be adopted.

It is important to note that nothing covered by this Stipulation affects revenue requirement in this docket. It deals with what for the present will remain Account 191 matters. Capacity release credits will offset pipeline transportation costs billed to Mountain Fuel in that Account.

H. SUMMARY

Our revenue-requirement decisions are reflected in appended Table 1, Summary of Revenue Requirement Decisions.

III. DISCUSSION, FINDINGS & CONCLUSIONS WITH RESPECT TO REVENUE SPREAD AND RATE DESIGN

A. STIPULATION ON RATE DESIGN

Mountain Fuel filed its general rate increase application April 2, 1993, proposing substantial changes in customer class cost of service and rate design. These were said to be in response to major cost shifts and other changes caused by FERC Order 636, and in anticipation of the September 1, 1993 conclusion of the Questar Pipeline Company compliance hearing at the FERC.

As proposed in the application, customer classes were to be grouped as "core" and "non-core," each subject to distinct ratemaking treatment and each having separate access to gas supplies. Gas supplies owned by Mountain Fuel were to be reserved for core customers only. A new interruptible sales service was proposed. The Application requested an increase in interruptible transportation rates, based on a proposed allocation to such customers of roughly $7.3 million of the estimated $13 million of supplier non-gas costs shifted to Mountain Fuel by Order 636. Several other matters necessary to implement this scheme were also addressed. The Company requested a substantial interim rate increase to be effective September 1, 1993.

Parties filed a stipulation resolving all these issues on August 26, 1993. Our Order Adopting Stipulation and Settlement was issued October 19, 1993.

FERC Order 636 is the culmination of the FERC's lengthy efforts to restructure the natural gas industry. It will profoundly affect the relationship between pipeline and local distribution companies. To fully consider this matter, we permitted the use of a rolling test year intended to include the results of the Questar Pipeline Company Order 636 compliance proceeding at the

FERC. But consideration of Order 636 and Mountain Fuel's proposed response also had the effect of changing the usual order of our rate case proceeding. Rate design, and to an extent cost of service, were resolved prior to determination of revenue requirement. Thus, while the Stipulation resolved all related rate design issues, and established interim rates, effective September 1, 1993, for transportation service, final rates await our determination of revenue requirement.

The net result of this Stipulation is a substantial reduction in the usual rate case analysis of cost of service and rate design. Because general service classes are the vast bulk of Mountain Fuel's service, and given the treatment accorded the large transportation and potential sales customers by the Stipulation, this is not a particular concern. The parties raised only minor rate design issues other than those covered by the Stipulation. These are discussed in Section C. below. Cost of service and revenue spread is discussed in Section B.

B. COST OF SERVICE AND REVENUE SPREAD

Stipulation and Settlement No. 1 covers revenue spread and rate design for interruptible service. We adopted the Stipulation in an order dated October 19, 1993. It conditions revenue spread for the remaining schedules. In his direct testimony Company witness Allred proposed that: "Within each firm class the Company proposes that the rates be designed so that the revenue requirement minus customer charge revenue is collected on a uniform percentage increase of the non-gas commodity charge in each block of all core rate classes." (The term "core" refers to firm customers.) This proposal was uncontested by the other parties. We judge it a reasonable basis for the spread of the revenue change and adopt it for use in this docket.

C. RATE DESIGN

Two rate design issues were raised by the parties in addition to those settled by stipulation. These concern the customer charges of firm customer groups. Mountain Fuel proposed increasing the existing general service customer charge from $5.00 to $6.50. This was opposed by both the Division, which argued that the $5.00 charge should remain unchanged, and by the Committee, which recommended that the customer charge be eliminated. The Division's cost of service analysis supported the $5.00 amount. We reject the Company's proposal because it includes costs that we have elsewhere found should be excluded from an appropriate cost-based customer charge. We reject the Committee's recommendation because, as we have consistently found in other dockets, there are customer costs of providing utility service that are properly recovered in a customer charge. No new evidence surfaced in this proceeding to cause us to revise this position. The Division's analysis is based on the costs we have designated in previous dockets to be properly recoverable in a customer charge.

Therefore, we accept the Division's recommendation and will not alter the $5.00 customer charge.

Also included in the Division's analysis was a recommendation to separately identify and price the types of meters in the general service customer class. Currently all are paying the $5.00 customer charge, despite differences in customer size and in corresponding metering complexity. Larger customers cause the Company to incur costs for metering which exceed the existing $5.00 charge. The Division recommended replacing the uniform customer charge with a set of meter-based customer charges. Three additional categories of meters were identified for repricing. Division witness Alt performed an analysis of the metering costs and recommended that Class II meters be charged $11.00 per month, Class III meters be charged $34.00, and Class IV meters be charged $195.00. The Company recommended higher amounts than the Division. On the basis of the Division's analysis of the customer costs that should be included in a customer charge which we have accepted, we will adopt the Division's recommendation.

IV. ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED that:

1. The Company file revised schedules and tariffs reflecting and incorporating the findings and conclusions of this Order and calculated to result in annual revenues of $155,362,477

and yield an overall annual return of 11.00 percent commencing January 1, 1994.

2. Stipulations 2 and 3 of the parties be and are approved.

3. The Division perform and report by September 30, 1994 a complete analysis of the Company's deferred income tax balance.

4. The Division perform and report an analysis of the Company's gas supply organization after one year of operation.

5. To the extent that the Commission has inadvertently omitted from the ordering provisions of this Order any duty or obligation intended to be imposed upon the company or Division, which duty or obligation is otherwise clear from the language of the preceding portions of this Order, it is hereby incorporated herein by this reference and made a part hereof.

5. Any party, shareholder, bondholder or other person pecuniarily interested in the Company may apply for reconsideration of any matter determined herein. The application for reconsideration must be filed within twenty (20) days after the issue date of this Order. An application for reconsideration not granted by the Commission within twenty (20) days of filing is denied. If the application for reconsideration is denied, a petition for judicial review of any matter determined in the Order must be filed with the Court within thirty (30) days of the date of the denial of the application for reconsideration.

DATED at Salt Lake City, Utah, this 10th day of January, 1994.

/s/ Stephen F. Mecham, Chairman

(SEAL)

/s/ James M. Byrne, Commissioner

/s/ Stephen C. Hewlett, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

COMMISSIONER STEPHEN C. HEWLETT DISSENTING IN PART

I concur with the results of this Order with the exception of incentive compensation and test year.

INCENTIVE COMPENSATION

I respectfully disagree with the decision of my colleagues in this order to fund $600,000 for incentive compensation. Incentive compensation for Mountain Fuel is an issue the Commission has not previously dealt with and approved for this Company. While I agree with my colleagues that incentive compensation is a reasonable and proper way to motivate and reward Company employees for superior performance benefiting ratepayers, we are allowing ratepayer funding of plans that have not been approved by this Commission and that will be triggered by net income only. That would mean if Company employees met their customer service goals and employee productivity goals, yet the net income trigger of $21.6 million were not attained because warm weather decreased natural gas sales for the year, employees would not be rewarded and the incentive funds would go straight to shareholders in the form of increased net income. That is unacceptable to me.

I would prefer to see a non-lapsing account set up for the purpose of carrying-over incentive compensation funds from one fiscal year to the next if employee customer service and productivity goals are not attained in a particular year. That would alleviate my concern that these funds could go to the Company's shareholders.

TEST YEAR

My preference for the test year in this docket, as delineated in my dissent regarding the test-year Order issued on May 24, 1993, was a complete calendar year to insure proper matching of revenues, expenses and investments. It concerned me that we placed the Division and the Committee at such a huge disadvantage by making them audit two different calendar years (1992 and 1993). The use of a rolling test year was also a concern to me. The Division and the Committee had only two weeks from receipt of final end-of-test-year numbers from the Company until the onset of hearings in November 1993. I believe this limits the ability of regulatory agencies to fully review and analyze the reasonableness of historical operating results. Also, important issues that the Commission had ordered examined in previous dockets, were not looked at in this rate case; i.e., accounting treatment and program evaluation of natural gas vehicles.

I note also that the non-calendar test year used did not match the Company's fiscal year and, thus, did not include year-end accrual adjustments, corrections and audit information. There is usually a large number of year-end adjustments to true-up accruals which take place in December of each fiscal year. Because of the test year approved by my colleagues in this case, we don't know whether the accruals accounted for by the Company in this docket were reasonable or not.

Another problem with the use of this test year was that the time permitted for the Commission to deliberate, decide, and issue its written order was entirely too short. With the interruption of the Christmas and New Year holidays in an already small time frame, the timely issuance of our Order would have been impossible except for the exceptional and dedicated staff of the Commission. I praise the tireless efforts of our staff in accomplishing this incredibly difficult task.

/s/ Stephen C. Hewlett, Commissioner