1979 WL 461903 (S.D.P.U.C.), 32 P.U.R.4th 1

Re Minnesota Gas Company

(F–3302)

South Dakota Public Utilities Commission

September 26, 1979

Before Klinkel, Fischer, and Stofferahn, commissioners.

By the COMMISSION:

On the twenty-sixth day of March, 1979, Minnesota Gas Company, hereinafter Minnegasco or company, filed with this commission an application to increase its retail gas revenues by appproximately $1,597,000. This represented an overall increase of 8.35 per cent affecting 35,500 customers in South Dakota.

Thereafter, the commission entered orders of suspension and granted motions to intervene filed by South Dakota ACORN and John Morrell and Company. Procedural dates were scheduled and hearings on Minnegasco's rate increase application were held by the commission commencing on the fourteenth day of August, 1979, and concluding on the seventeenth day of August, 1979. Thereafter, briefs were ordered by the commission to be filed by the parties.

The commission has carefully reviewed the entire record in this proceeding and hereby enters the following:

Findings of Fact

I.

1979 Plant in Service

(A) Staff Position:

Staff points out that Minnegasco's proposed adjustments included a number of items based on expenses to be incurred in 1979 that were related to projected 1979 plant in service. Staff recommends that the commission reject those adjustments. Staff contends that they are not known and measurable changes and effectively represent a 1979 projected test year.

Staff points out that Minnegasco proposed four adjustments to rate base, each of which consisted of increasing the average 1978 balance to year-end 1978 levels and adding an amount which reflects the change in the average balance for the 1979 proposed additions.

Staff witness Brown testified that this type of adjustment should not be allowed to the test year. She testified to the enormity of the task that would confront the commission if these types of adjustments, based entirely upon estimates, were routinely allowed. Staff witness Brown pointed out that examining all of the assumptions which go into such adjustments would as a practical matter be impossible. Further, staff witness Brown testified that even if Minnegasco, commission staff, intervenors, and the commission were to reach an agreement upon the reasonableness of all of the assumptions, the estimates may not materialize exactly as projected and, thereby, Minnegasco would thus be either overcollecting or undercollecting through rates established by reliance on estimates. She further stated that this violates the fundamental regulatory principle that consumers' rates should be based on actual costs adjusted for only known and measurable changes.

Staff recommends that an average actual test year adjusted only for known and measurable changes be employed. Staff contends that this avoids the burdens as well as risks inherent in the proposed adjustments made by Minnegasco which are based upon estimates. Staff further points out that the commission's past precedent fully supports ***3** utilization of an average actual test year adjusted only for known and measurable changes that will occur within twelve months after the end of an historical test year. Staff points out that each such adjustment for a known and measurable change must be accompanied by corresponding adjustments to assure that costs and revenues continue to match. Staff points out that the matching requirement is a basic principle in proper rete making and should not be violated. Staff recognized a number of adjustments which were known and measurable as a labor increase which will not occur until as late as October, 1979, a full nine months beyond the end of the test year utilized by all parties in this proceeding.

Staff notes that company contends its adjustments are known and measurable and should be allowed on that basis. However, staff points out that company's proposed adjustments are based upon historical trends, projections of new customers, experience of its personnel, and other estimates. Staff contends that Minnegasco's proposed adjustments require a great deal of judgment, as opposed to any methodology, in deriving its estimates and projections. Staff points out that Minnegasco's construction budget was utilized for a number of items in its proposed rate base adjustments. Staff notes that the budget is prepared in August or September of the prior year and is not subsequently revised in order to reflect current conditions. Staff contends that such a basis is speculative and not subject to confirmation, serious analysis, or verification. Staff further points out that further difficulties occur when attempting to classify construction in terms of expenditures related to customer or revenue growth. Specifically, staff notes that work orders can easily be erroneously classified which will totally distort the projections and estimates for rate making. Additionally, simply because an item appears in a budget, that does not assure that it will actually be constructed. Staff further contends that Minnegasco's approach is tantamount to suggesting that if some type of change, however great or small, may occur, Minnegasco is entitled to arbitrarily attempt to quantify the change. Staff points out that this is the antithesis of the sound rate-making principle of recognizing known and measurable changes, and not speculative estimates and projections. Staff concludes that Minnegasco's proposed adjustments do not constitute in any sense known and measurable changes and, consequently, should be rejected accordingly.

(B) Company Position:

Minnegasco contends that its proposed adjustments to 1979 plant in service should be adopted. Minnegasco witness Petersen testified that the adjustments are known with reasonable certainty and measurable with reasonable accuracy. Company witness Petersen testified that the first part of each adjustment involves an increase of the average 1978 level to year-end 1978. Company witness Petersen testified that this is known and measruable as an absolute certainty and that it is based on actual 1978 end-of-year balances. Company witness Petersen further testified that the second part of the adjustment reflects 1979 additions which in his opinion are reasonably known and measurable. The 1979 proposed adjustments are based upon forecasts and use of historical data ***4** for replacements coupled with existing and current information for labor purchases and related components. Company witness Petersen further testified that matching occurs in that the adjustment of revenues and expenses for the same number of additional customers have been proposed by Minnegasco.

Commission Findings

The commission finds that staff's recommendation should be adopted for the reasons set forth in (A) above. The commission finds that Minnegasco's proposed adjustments include a number of items based on expenses to be incurred in 1979 that were related to projected 1979 plant in service. The commission finds that those adjustments are not known and measurable changes. Further, the commission finds that Minnegasco's filing in this regard represents a 1979 projected test year. The commission finds that not only is a projected test year impossible to fully evaluate and scrutinize, but moreover, a projected test year based upon estimates is in total contravention of the rational and sound rate-making principle of utilizing a test year adjusted for known and measurable changes. The commission finds that utilization of an average actual test year adjusted for known and measurable changes avoids the impossible task of evaluating the reasonableness of all of the assumptions, predictions, projections, and estimates involved in such a test year as well as lessens the possibilities of overcollection or undercollection by Minnegasco during the period the rates in this proceeding will be in effect.

The commission further finds that the fundamental rate-making principle of matching is violated by Minnegasco's poposed adjustments. The commission finds that Minnegasco's construction budget is an unreliable basis for establishing rates in this proceeding. The flaws of such an approach have been glaringly pointed out in this proceeding.

II.

Average Plant Balance

(A) Staff Position:

Staff witness Rislov recommended two adjustments to the plant in service. The first adjustment was for the inclusion of a January 1, 1978, figure in the calculation of average plant in service during 1978. Staff contends that without such an adjustment, an average monthly plant in service does not include any average amount for the month of January, 1978, and does not accurately represent the average plant over the whole year. Staff contends that the principle is the same as that used in calculating the average of plant in a single month, which would involve taking and dividing by two the amount of plant at the beginning and end of the month or averaged to compute the average amount over the period. Staff notes that Minnegasco utilized this well-accepted 13-month balance method in portions of its application. Staff further notes that Minnegasco witness Petersen did not argue with the position of Mr. Rislov, but rather only disputed Mr. Rislov's calculation which has been revised by staff accordingly. As to company's criticism of staff's deletion of the acquisition adjustment from accumulated depreciation, staff has ***5** provided company with a revised calculation incorporating company's acquisition adjustment.

(B) Company Position:

Company contends that while the revised calculation by staff is satisfactory, staff has, nonetheless, been inconsistent in its handling of the gas plant acquisition adjustment for computing the January 1, 1978, balance. Company contends that Mr. Rislov's revised calculation reflects the 1978 acquisition adjustment as a deduction in arriving at the January 1, 1978, plant-in-service balance. Company notes that the related accumulated depreciation applicable to the gas acquisition adjustment was not deducted from the January 1, 1978, accumulated depreciation balance by Mr. Rislov. Company contends that this inconsistency is erroneous and should not be allowed.

Commission Findings

The commission finds that staff's recommendation regarding average plant balance should be adopted for the reasons set forth above. The commission finds that staff's inclusion of a January 1, 1978, figure in the calculation of average plant in service during 1978 is totally proper. The commission finds that without such an adjustment, an average monthly plant in service would not include any average amount for the month of January, 1978, and, consequently, would not accurately represent the average plant over the entire test period. The commission finds that this is absolutely necessary when matching test-year revenues. The commission further finds that commission staff has made the revisions necessary to comply with valid company concerns. The commission further finds that staff's final recommendation incorporates said revisions and should be adopted accordingly.

III.

Exclusion of Construction Work in Progess

(A) Staff Position:

Staff witness Rislov testified that construction work in progress should be excluded from rate base. Staff witness Rislov testified to the general principle that ratepayers should only be required to pay for plant from which they derive benefit; i.e., plant that is used and useful to those ratepayers should be allowed in rate base. Staff notes that Minnegasco does not dispute the principle that CWIP should be excluded from rate base but rather that as a practical matter there was no CWIP in 1978. However, staff points out that the basis for staff witness Rislov's calculation excluding average monthly CWIP is related to Minnegasco's use of Account 107, CWIP, and to Minnegasco's admission that there was CWIP in 1978. Staff points out that based on Minnegasco's representations that this plant was used and useful within thirty days, staff witness Rislov acknowledged that Account 107 included plant in service and recommended including a portion of this plant in rate base. Staff witness Rislov's calculation estimates the amount of time that the projects included in Account 107 are underway before they go into service and is based on the very general information provided by the company which indicated that all 1978 CWIP was completed in less than thirty days. Staff ***6** witness Rislov determined the average CWIP additions per month and in so doing estimated that an average Account 107 expenditure would take fifteen days to become used and useful. He then excluded the resulting amount in an average month from rate base.

Staff contends that Minnegasco's own testimony substantiates staff witness Rislov's conclusions. Staff notes that company witness Petersen indicated that certain items in Account 107 were used and useful when purchased but that others, such as new distribution mains, can take from one to two weeks up to thirty days. Staff notes that Mr. Petersen also pointed out that in a different period than 1978 there may be some projects that would take up to sixty days and that he knew of two projects budgeted for 1979 that would take thirty days or a little longer. Staff contends that Minnegasco has fully substantiated staff witness Rislov's adjustment and that to fail to make that adjustment would provide Minnegasco the ability to rely upon vagaries and nuances created by its own administrative and accounting procedures. Staff concludes that staff witness Rislov's adjustment, while relatively small, properly represents the amount which excludes construction work in progress from Minnegasco's rate base.

(B) Company Position:

Company contends that staff witness Rislov's adjustment should be disallowed. Company contends that it had no construction work in progress in South Dakota during 1978. Further, company contends that general plant additions are used and useful when purchased, that most construction is completed within a day or two, and that new main construction can take up to thirty days but usually lasts from one to two weeks. Consequently, company contends that staff witness Rislov's adjustment is without merit and should be rejected.

Commission Findings

The commission finds that staff's recommendation regarding exclusion of construction work in progress should be adopted for the reasons set forth in (A) above. The commission finds that ratepayers should not be required to pay for plant from which they derive no benefit. The commission finds that only plant that is used and useful to those ratepayers should be allowed in rate base. The commission finds that Minnegasco's accounting methods may not be utilized to avoid the elimination of monthly construction work in progress and that commission staff's determination of the construction work in progress existent in 1978 and the exclusion thereof from rate base is totally proper. The commission finds that Minnegasco's own witness has fully confirmed the reasonableness of the amount of construction work in progress which was recommended for exclusion by staff.

IV.

Working Capital

(A) Staff Position:

Staff contends that Minnegasco's requested inclusion in rate base of $226,509 for cash working capital was inappropriate. Staff witness Rislov, after analysis and evaluation of Minnegasco's application and upon adjustments made ***7** to Minnegasco's lead-lag studies, indicated Minnegasco had a negative need for cash working capital from investor-supplied funds of $315,629. Staff points out that as a result of funds being held prior to the time they have to be paid out, Minnegasco was more than compensated for the lag between the time expenses were incurred and the time Minnegasco received payment. Additionally, staff witness Rislov rejected several bank balance items that Minnegasco claimed were necessary and that Minnegasco had included in its cash working capital calculations. Staff notes that excluding its claimed cash balance requirement, Minnegasco also found a negative need for working capital of $166,963.

Staff witness Rislov took account of the payment lags for long-term debt interest and preferred stock dividends. Staff witness Rislov testified that this was mere recognition of the fact that these funds are available to Minnegasco once they have been received for use to cover working capital requirements even though ultimately they will be paid out as interest or dividends. Staff notes that company maintains the funds accounted for monthly as dividends and interest in the same bank account as the rest of Minnegasco's cash. Staff points out that while interest on long-term debt and dividends on preferred stock will ultimately be transferred to bond and shareholders, company retains the funds pending the quarterly or semiannual payment dates and company can thereby make use of those funds. Staff notes that if this were not the case, Minnegasco would be inefficiently and improperly managing its funds.

Staff summarizes Minnegasco's position as being that only stockholders and bondholders should be allowed to benefit from funds that are being temporarily held by Minnegasco prior to being disbursed and distributed to those shareholders and bondholders. Staff contends that this is erroneous. Staff notes that the funds are in no way legally segreated and payment is not required until periodic payment dates. Additionally, staff points out that it could be contended that the return associated with long-term debt and preferred stock already contains an increment to compensate bondholders and preferred shareholders for the lag or delay in payment of the interest or preferred dividends. Staff notes that if the interest and dividends were to be paid at an earlier date, investors would have been willing to accept a lower rate of return taking into consideration the time value of money.

Staff further points out that a proper matching of costs requires that the delay in payment to bondholders and preferred shareholders be reflected in the cash working capital determination. Without such consideration, consumers would pay for that cost twice; i.e., once in the form of higher embedded costs of long-term debt and preferred stock and again in the form of a return on a working capital requirement already supplied by the customers. Staff contends that Minnegasco's refusals to include these temporarily available funds in its lead-lag study overstates the amount of additional working capital needed and places an additional burden on consumers while giving a windfall to common shareholders.

Staff witness Rislov also rejected several of the expenses proposed by Minnegasco as either inappropriate, or not shown to be necessary expenses. The first item staff witness Rislov disallowed ***8** was cash balances required in lieu of service charges to the bank. Staff witness Rislov testified that if Minnegasco must maintain minimum bank balances due to avoid service charges, Minnegasco must demonstrate both the net amount required and that the costs to consumers of such a requirement are less than service charges avoided. Staff notes that system-wide, Minnegasco would have had to pay $110,230 for bank service charges in 1978 with South Dakota's portion being $7,352. However, Minnegasco did not pay any of this amount because it maintained $1,660,000 system-wide in bank accounts with South Dakota's portion being $110,722. Company witness Petersen testified that maintenance of these bank balances is Minnegasco's form of payment for bank services. However, staff notes that Minnegasco might well have maintained balances in this amount regardless of whether the banks would treat them as payment for service charges. Staff witness Rislov stated that it has been staff's position and has support in commission precedent that it is Minnegasco's burden of proof to demonstrate that these costs are actually incurred and, if so, to establish that the revenue requirements associated with the maintenance of minimum balances are less than those associated with service charges. Accordingly, staff witness Rislov requested Minnegasco to demonstrate that maintaining the balances was a true cost and that he only desired to carefully examine the circumstances behind the balances in order to ascertain whether they were true costs. After hearing in this matter Minnegasco provided data to staff witness Rislov sufficient to establish that the company did maintain cash balances in lieu of bank service charges. Staff has agreed to allow $7,352 representing service charges, as it is the most economical alternative available to the company, and staff's recommendations to the commission reflect that inclusion.

Staff contends that Minnegasco should not be allowed to recover in rate base the compensating balances related to company's line of credit. Staff points out that company witness Petersen testified that the credit was not used in 1978 except in the first quarter to pay a previously outstanding debt and was not used during the first part of 1979. Staff further points out that while company's 1978 construction budget system-wide was $19 million, the line of credit amount of over $25 million was untouched. Staff further notes that Minnegasco's construction will continue to be principally short-term installation of mains and services and meters, and represents small construction expenditures. Consequently, staff contends that the costs of maintaining these balances have not been shown to be necessary and that the size of the line of credit maintained is entirely out of line with Minnegasco's current needs. Further, staff points out that Minnegasco never reconciled the amount maintained with Minnegasco's actual short-term borrowing needs and also failed to show why some other form of short-term notes would not be a less expensive alternative. Staff points out that approximately 40 per cent of residential consumers are on Minnegasco's budget plan and that this should go a long way towards evening out the seasonal cash-flow needs of Minnegasco thereby lessening the need for credit. Staff notes that company witness Petersen concurred that the need for a line of credit would drop if all customers went on a budget plan yet nowhere did ***9** Minnegasco indicate whether more customers could be expected to change to a budget plan or even the effect of the current budget plan customers on the need for a line of credit.

Staff witness Rislov testified that a further reason for disallowing the cost of compensating balances for lines of credit is that credit is normally associated with construction costs and, consequently, should be excluded from rate base and capitalized as a part of the allowance for funds used during construction. This is the method utilized by FERC to allow recovery. Finally, staff points out that it is incorrect to allow recovery in rate base when the company has shown construction expenditures are made every year, and will be increasing in the future.

Staff witness Rislov disallowed Minnegasco's three-day allowance for cash collections on hand and in process of transfer purportedly reflecting the time lag between receipt of checks and other items and the time when money is credited to Minnegasco's bank accounts. Staff witness Rislov testified that the amount should be disallowed because Minnegasco did not provide the related analysis of positive float; i.e., extra money available to Minnegasco due to the lag between the time it writes checks and the time they are cashed. Staff contends that company did not substantiate its three-day allowance for cash collections on hand and in process of transfer and, accordingly, it should be disallowed. Staff witness Rislov pointed out that Minnegasco has precisely calculated a figure it wants included for treatment in this proceeding out totally dismisses a float calculation to determine the necessity for its claimed allowance. Subsequent to the hearing, company did calculate positive float. Staff contends that the positive float, along with the use of month-end receivables, which would tend to overstate the revenue lag, would offset the three-day lag and allow the company adequate cash balances.

Staff witness Rislov disallowed an amount for imprest accounts in South Dakota because there was no showing that maintenance of this amount was an actual and necessary expense. Staff contends that Minnegasco did not show that the amounts were required to be expressly maintained by Minnegasco and would not have been kept in the bank, in whole or in part, regardless of the service charge, and has not shown that the amount claimed avoided service charges. Further, staff notes that Minnegasco has not evaluated whether the net cost of a possible service charge might have been preferable. Staff concludes that Minnegasco has simply failed to show the actual size or necessity of the expense and the amount should be disallowed, particularly in light of their previous showing that service charges can be more economical.

Staff witness Rislov also recommended disallowance of the cashier working funds. Staff has stated that such amounts are already included in working capital as operation and maintenance expenses. Staff contends that Minnegasco uses these funds for operation and maintenance expenses, and to allow this amount in this fashion would be double counting. Consequently, staff contends that the amount should be excluded.

Finally, staff makes several recommendations regarding future filings. Staff contends that Minnegasco should be required in future cases to furnish information sufficient for staff to perform an independent revenue lag study. In this proceeding, staff witness Rislov was ***10** forced to rely on Minnegasco's revenue lag data. Staff points out that Minnegasco's method of calculating revenue lag relies entirely on average month-end balances and does not incorporate any information about actual individual customer behavior. It is the position of staff that Minnegasco should furnish information for all customer classifications on the time between meter reading and billing and between billing and payment. Staff points out that since Minnegasco's bills are computerized, this should not be a difficult endeavor and that other utilities in South Dakota routinely provide the information in the recommended format. Staff notes that company witness Petersen felt that keeping track of the customer accounts on a monthly basis would be extremely expensive, and, accordingly, staff recommends that Minnegasco should, at a minimum, be required to supply information on a statistically significant number of customer accounts for each customer class in order to avoid expense but to provide a basis in its future filings for independent analysis.

(B) Company Position:

Company contends that staff's adjustments regarding cash working capital are erroneous. Company witness Petersen testified that cash balances are required and are necessary for use at local offices and banks as working funds, because three days' receipts are always in transit, and because average collected balances must be on deposit to support activity charges and lines of credit. Company witness Petersen testified that staff's basis for disallowance was incorrect and described the manner in which the lead-lag study fails to recognize cash balance requirements. Company witness Petersen pointed out that the time frame from payment of bills to local office to deposit in a principle bank and that bank's collection of the funds averages three days. Company witness Petersen testified that positive bank float is very short and that 78 per cent of disbursements have a zero float. He further testified that bank service charges are like any other expense in that the only difference is in the method of payment. As a result, balances are maintained by Minnegasco to compensate the banks for the bank's services to Minnegasco. Company witness Petersen further testified that the compensating balances for lines of credit are required and that only the amount for establishment of the credit line is included. He noted that none was for actual borrowings. Further, company witness Petersen testified that the company's documentation establishes the need for credit lines and the actual maintenance thereof.

Company contends that since there was no construction work in progress in 1978 in its view, staff's recommendation that compensating balances should be recovered through the AFUDC rate will simply not work. Company contends that the need to maintain cash balances has been fully established and the Minnegasco must be compensated for this facet of its cash working capital.

Company disputes staff's inclusion of payment lags for long-term debt interest and preferred stock dividends. Company contends that staff ignores the fact that a return on these items is due Minnegasco at the time service is rendered and that the cash funds available from this lag belong to the stockholders.

In sum, Minnegasco urges adoption of its recommendation and rejection of commission staff's determination.

11 *Commission Findings

The commission finds that staff's recommendation regarding working capital should be adopted for the reasons set forth in (A) above. The commission finds that as a result of funds being held by Minnegasco prior to the time they have to be paid out, company has been more than compensated for the lag between the time expenses were incurred and the time Minnegasco received payment therefor. Additionally, the commission finds that certain items have been shown not to be necessary and, as a result, should be excluded from Minnegasco's cash working capital requirements.

The commission finds that payment lags for long-term debt interest and preferred stock dividends must be considered. The commission further finds that this recognizes the fact that these funds are available to Minnegasco once they have been receibed for use to cover working capital requirements even though ultimately they may be paid out as interest or dividends. The commission funds that Minnegasco maintains these funds in the same bank account as the rest of Minnegasco's cash. The commission finds that while the interest on long-term debt and dividends on preferred stock will ultimately be transferred to bond and preferred stockholders, Minnegasco clearly retains the funds pending the quarterly or other payment dates and Minnegasco thereby has the opportunity to make use of those funds. If Minnegasco did not efficiently and properly manage those funds, the commission finds that that is no basis for Minnegasco attempting to require the ratepayers to compensate for such inefficiency. The commission further finds that the returns associated with long-term debt and preferred stock may already contain an increment to compensate bondholders and preferred shareholders for the lag or delay in payment of the interest or preferred dividend. Accordingly, the commission finds that if the interest and preferred dividends were to be paid at an earlier date investors would retionally be expected to accept a lower rate of return taking into consideration the time value of money. Further, the commission finds that a proper matching of costs requires that the delay in payment to bondholders and preferred shareholders must be reflected in the cash working capital determination. Absent such matching, consumers would be required to pay for the cost twice; once in the form of higher embedded costs of long-term debt and preferred stock and once again in the form of a return on a working capital requirement already supplied by the customers themselves. The commission finds that this cannot and should not be allowed.

The commission finds that staff's allowance of service charges in lieu of cash balances required by the bank is proper and should be permitted. The commission finds that the documentation supplied as a posthearing exhibit provides support for and substantiation of the propriety of allowing service charges.

The commission finds that staff's treatment of compensating balances related to Minnegasco's line of credit is proper. The commission finds that the credit was not used in 1978 except in the first quarter to pay a previously outstanding debt and was not used during the first portion of 1979. The commission finds that while the company's 1978 construction budget system-wide was $19 million, the line of credit amount of over ***12** $25 million was undrawn upon. The commission finds that Minnegasco's construction will continue to be principally short-term installation of facilities which represent small construction expenditures. The commission finds that, consequently, the costs of maintaining the balances have not been shown to be necessary and that the size of the lines of credit maintained is entirely inconsistent with Minnegasco's current needs. The commission further finds that Minnegasco has never reconciled the amount maintained with the actual short-term borrowing needs of Minnegasco and has also failed to establish why some other form of short-term financing would not be a less expensive alternative. The commission rejects Minnegasco's low revenue during the summer argument in that Minnegasco has failed to take into account the increasing number of customers utilizing the budget plan which allows equal payments throughout the year commencing in July, and which approximately 40 per cent of Minnegasco's residential consumers are utilizing. The commission further finds that the cost of compensating balances for lines of credit is normally associated with construction costs and, as a result, if such costs are shown to be necessary, such costs should be capitalized as a part of the allowance for funds used during construction.

The commission finds that the disallowance by staff of Minnegasco's three-day allowance for cash collections on hand and in process of transfer is proper and should be adopted. The commission finds that any requirement to cover cash collection on hand and in process of transfer is met, in part, with float. The commission further finds that Minnegasco's method of calculating revenue lag relies on average month-end accounts receivable balances. The commission finds that the overstatement explicit in Minnegasco's averaging method has not been measured and, consequently, the revenue lag utilized by company and staff must be regarded as approximate only. In light of this, the commission finds that the average being utilized is already overstated and that any further allowance for cash allegedly needed to account for the delay between the receipt of revenues by Minnegasco and the processing of those receipts—i.e., the purpose of the allowance—is totally unwarranted.

The commission finds that staff's disallowance of an amount for imprest accounts in South Dakota for failure to show that maintenance of said amount actually occurs and that the expense is actually necessary is proper. The commission finds that Minnegasco has not established that the amounts were required to be expressly maintained and would not have been kept in the bank, in whole or in part, regardless of the service charge. The commission finds that Minnegasco has not shown whether other claimed balances would overlap, and that Minnegasco has not shown that the amount claimed avoided service charges. Further, the commission finds that Minnegasco has not evaluated whether the net cost and the service charge may be preferable. The commission finds that disallowance of an amount for imprest accounts in South Dakota is totally proper and is hereby adopted.

The commission finds that disallowance of the cashier working funds is fully supported and should be adopted herein. The commission finds that there was no proof that the amount claimed was representative of normal operations ***13** and that Minnegasco has already received treatment in the lag study as these amounts represent operation and maintenance expenditures. As a result, the commission finds that the exclusion is entirely proper.

The commission has reviewed the positions of Minnegasco and staff regarding future rate filings. The commission finds that Minnegasco and commission staff should arrive at a mutually satisfactory arrangement whereby Minnegasco could supply information on a statistically significant number of customer accounts for each customer class in order to avoid expense and, concurrently, provide a basis in Minnegasco's future filing for independent analysis.

V.

Deferred Cost of Gas Purchased from Northern Natural Gas Company and Deferred Supplemental Gas Costs

(A) Staff Position:

Staff contends that Minnegasco should not be permitted to recover twice for the lag in payment for gas purchased from Northern Natural Gas Company. Staff points out that there are two issues presented by Minnegasco's method of presenting its deferred costs for gas purchased from its supplier, Northern Natural, which it calls unbilled cost of gas. Staff contends that unless its recommendation is followed, the cost will be recovered once in the working capital allowance and once again as a prepayment. The second issue raised by staff is whether Minnegasco properly should treat this cost as part of its working capital study as staff recommends or, alternatively, as a prepayment.

Staff notes that the deferred natural gas cost represents the cost of gas purchased from Northern Natural on a monthly basis but not yet billed to Minnegasco's customers. Due to the fact that Minnegasco has 21 different billing cycles, recovery of the cost of any month's gas purchased from Northern Natural takes more than a month; e.g., some of the bills to customers will not be sent until almost a month after the cost is incurred. Staff contends that in Minnegasco's filing, Minnegasco double counted the amount in Minnegasco Exh C–1. Company witness Petersen testified that the lead-lag study accounted for actual recovery of gas costs. However, staff contends that from the manner Minnegasco filed its case in this proceeding, double counting occurred.

Staff points out that a combination of recommendations of staff witness Rislov and Brown would rectify the double counting and provide Minnegasco with recovery of its costs. Staff contends that the unbilled cost of gas included by Minnegasco as a prepayment should be removed from the rate base since any lag in recovery is accounted for by the cash working capital calculation. Staff witness Brown recommended deleting the total deferred gas costs from the rate base. Staff witness Rislov's cash working capital analysis was based upon Minnegasco's with certain revisions and adjustments. Like Minnegasco, staff witness Rislov fully accounted for the unbilled cost of gas in his working capital recommendation. Staff points out that Minnegasco does not have a permanently deferred unbilled cost of gas. The amount paid to Northern Natural for gas in any one month is billed out and those bills are paid. Both company witnesses Swetman and Petersen testified to this ***14** circumstance. Staff notes that it is only the overlap caused by the fact that it takes more than a month to bill and receive payment for a month's gas cost that causes an amount o be unbilled gas cost at all times. However, it is not always the same amount since gas use and gas costs vary seasonally. Minnegasco is free to maintain records of this variable amount in an informational account if it so wishes. The unbilled cost of gas is part of the lag in recovering costs and is primarily offset by Minnegasco's own lag in paying Northern Natural for the gas. To the extent that the amount has not been fully recovered, this fact is reflected in the working capital determination.

Consequently, staff recommends that it is inappropriate for Minnegasco to treat this delay in payment as a permanent deferral. Staff witness Rislov testifies that it is more properly considered a timing difference because the amount turns over every month. Further, the timing difference is easily accounted for in the cash working capital study. Staff concludes that its recommendation which would incorporate these costs in the working capital determination is clearly preferable to a prepayment treatment, and to include these costs in both the prepayments and cash working capital would be double counting.

Staff further recommends that, rather than including the amount of deferred supplemental gas costs in Minnegasco's rate base, Minnegasco should be required to include the carrying charges caused by deferred recovery of cost as part of the costs of gas in its purchased gas adjustments. The situation regarding deferred supplemental gas costs exists because Minnegasco has to purchase propane gas above and beyond the amount included in the base rate for peak shaving. The additional costs related thereto are not billed to the customers until they are included in the rate through a PGA. Minnegasco only files a PGA once a year and once filed, Minnegasco begins to recover the costs of the previous year's supplemental gas. Hence, Minnegasco may not recover costs of supplemental gas associated with the past period for up to a year. Minnegasco desires to be compensated for the lag in payment by including the amount as part of deferred gas costs in its rate base. Staff witness Brown, however, recommends that the amount not be included in rate base because it is too speculative. Staff witness Brown points out that the amount Minnegasco will spend on supplemental gas and the amount of time it will take to recover costs associated therewith, depend on a number of factors including weather, costs of supplemental gas, and the terms of Minnegasco's currently effective PGA. Staff witness Brown notes that the company has not even attempted to make adjustments to this amount for various changes which may occur and that the future levels of supplemental gas costs is uncertain. She concludes that an error in estimating the typical deferred amount may result in over- or undercompensation for Minnegasco for associated carrying charges.

Staff witness Brown proposes a simple method which would include a cost component for the carrying charges by applying the overall allowed rate of return to the actual deferred cost balance when Minnegasco files its PGA. Staff further notes that the additional calculations required are not at all complex and that Minnegasco is in no manner penalized by utilizing staff's recommended ***15** method. Staff concludes that its recommendation will be far more precise than an attempt to forecast the balance and include in rate base that amount.

(B) Company Position:

Company witness Petersen testified that South Dakota deferred gas costs represent the commodity cost of supplemental gas supplies used for peak shaving and natural gas which have been purchased and delivered to customers but are unbilled at the end of each month and, consequently, are not reflected in revenue. Company witness Petersen stated that deferred income taxes on these deferred gas costs have been offset against the prepaid amounts. Company contests staff's elimination of the entire amount from prepayments in this proceeding and staff's recommendation that the carrying cost on all deferred gas costs be recovered as part of company's PGA. Company further contends that staff's treatment of unbilled cost of natural gas as being part of the lead-lag study is erroneous. Company maintains that it is entitled to recover carrying costs on both components of deferred gas costs and to do so most appropriately through inclusion as prepayments. Minnegasco contends that it would be simpler to include carrying charges on deferred gas costs in a general rate proceeding than in the PGA because of the additional complexities the carrying charge calculation would add to the PGA. Minnegasco contends that it has fully established that deferred unbilled costs of natural gas represent a permanent deferral due to the use of cycle billing and that those deferred costs are not reflected in the lead-lag study. Minnegasco urges inclusion of deferred gas costs as a prepayment in rate base and contends that its treatment of supplemental gas supply costs should, likewise, be allowed by the commission.

Commission Findings

The commission finds that staff's recommendation regarding deferred cost of gas should be adopted for the reasons set forth in (A) above. The commission finds that the cost will be recovered once in the working capital allowance and once again as a prepayment unless staff's recommendation is adopted. Additionally, the commission finds that the deferred cost of gas is properly treated as part of Minnegasco's cash working capital study and should not be treated as a prepayment.

The commission recognizes that due to Minnegasco's billing cycles, recovery of the cost of any month's gas purchased from Northern Natural takes more than a month. However, the commission finds that in Minnegasco's filing, Minnegasco has double counted that amount. Minnegasco witness Petersen testified that the lead-lag study performed by Minnegasco had accounted for actual recovery of gas cost. However, the commission finds that since Minnegasco also included this amount as a prepayment, double counting has occurred.

The commission finds that the unbilled cost of gas included by Minnegasco as a prepayment should be removed from prepayments since any lag in recovery is accounted for by the working capital calculation. The commission finds that both Minnegasco and commission staff fully accounted for the unbilled cost of gas in their respective working capital recommendations. The commission finds that it is only the overlap ***16** caused by the billing circumstance which creates an amount of unbilled gas cost at all times; however, it is neither the same amount since gas use and gas costs vary seasonally. The commission finds that the unbilled cost of gas is part of the revenue lag in recovering costs but is primarily offset by

Minnegasco's own lag in paying Northern Natural for that gas. To the extent that full recovery has not occurred, the remainder of the cost is reflected in the working capital determination. The commission finds that this issue is more properly considered a timing difference rather than a permanent deferral and, consequently, incorporation of those costs in the cash working capital determination is clearly preferable to treating same as prepayments. The commission further finds that staff's recommendation regarding proper treatment of supplemental gas costs should be adopted. Since Minnegasco has to purchase propane gas above and beyond the amount included in the base rate for peak shaving and in light of the delayed recovery of those costs through inclusion in Minnegasco's PGA at year-end, the commission finds that the amount should not be included in rate base but rather should be reflected as a cost component in the PGA. The carrying charges associated with these deferred supplemental gas costs will be recovered by applying the overall allowed rate of return to the actual deferred cost balance and including same as part of Minnegasco's PGA. The commission finds that Minnegasco's proposal to include the amount as part of a deferred gas cost in its rate base is too speculative since the amount involved will depend upon a number of factors including weather, costs of supplemental gas, and the terms of Minnegasco's currently effective PGA. The commission further finds that staff's recommendation serves to compensate Minnegasco for the delay in recovery of its supplemental gas costs and that the calculations required are not complex and will not cause any undue burden upon Minnegasco whatsoever.

VI.

Flow Through Versus Normalization

(A) Staff Position:

Staff witness Brown has recommended that, consistent with prior commission precedent, Minnegasco should flow through the deferred income taxes related to capitalized payroll taxes and employee benefits. In its filing, Minnegasco has normalized the tax benefit of payroll taxes and employee benefits which are capitalized on Minnegasco's books because the related expenses are recognized in the future through depreciation. However, staff points out that for income tax purposes, the costs are deducted currently producing an immediate tax benefit because current expenses reduce current taxable income. The issue is simply whether current ratepayers should receive the benefit of the tax savings Minnegasco actually experienced or whether the rates should reflect a fictional tax calculated as if the tax deduction had to be spread over the life of the plant. Staff contends that its recommendation reflects the actual taxes paid or payable by Minnegasco related to payroll taxes and employee benefits capitalized and, consequently, the costs imposed on ratepayers fully match the costs actually incurred to provide service to those ratepayers. Staff notes that Minnegasco's normalization method does ***17** not provide for such matching and reflects in rates taxes the company did not actually pay in 1978.

Staff contends that Minnegasco's arguments regarding normalization are without merit. Staff points out that if Minnegasco continues to construct plant for expansion or replacement, Minnegasco can continue to defer new amounts and, under tax normalization, recover more for taxes in each year than it actually pays in that year. This would result over time in a utility being compensated for more federal income taxes than it ever pays out. Additionally, inflation of construction costs which serves to magnify each new deferral relative to previous deferrals increases this effect. Finally, staff notes that the same dollar amount of benefit to consumers now is more valuable than that amount to consumers years later. Further, staff points out that the tax normalization approach assumes the tax circumstances are constant. However, if tax rates change, tax normalization no longer returns to the consumers the same benefit the company derived; e.g., the recent tax change resulted in an overcollection at 48 per cent for tax expense that a utility will experience, if at all, at 46 per cent. Further, if ratepayers pay for expenses which are in fact continually deferred, those ratepayers are making a capital contribution to the utility which is the responsibility of stockholders.

Finally, staff contends that tax normalization presupposes that the costs of ongoing operations and the costs of construction can be completely separated. Staff notes that this is not the case in that customers are paying a rate presently including rate of return for capital secured both for construction and present operations.

(B) Company Position:

Company recommends that tax normalization be utilized. Company witness Swetman testified that staff's recommendation is erroneous in that tax normalization is the only technique which will match the tax benefit received with the related expense. Company contends that the amount involved is actually a timing difference and is not a permanent difference. Further, company contends that since future ratepayers will pay the expense of the capitalized payroll taxes and employee benefits in the form of depreciation, those future ratepayers should also receive the applicable tax benefit. Company points out that staff's recommendation deprives future ratepayers of a benefit to which they are entitled. Company contends that since the expense giving rise to the benefit is not being recognized currently in rates, flow through of those benefits to current ratepayers results in a mismatch of revenues and expenses. Company concludes that the commission should allow normalization of capitalized payroll tax normalization of capitalized payroll

Commission Findings

The commission finds that staff's recommendation regarding the flow through of the deferred income taxes ralated to capitalized payroll taxes and employee benefits should be adopted for the reasons set forth in (A) above.

The commission finds that, consistent with all prior commission precedent, the flow through of the deferred income taxes related to capitalized payroll taxes and employee benefits should be adopted. The commission finds that for income tax purposes, the costs are ***18** deducted currently thereby producing an immediate tax benefit since current expenses reduce current taxable income. The commission finds that current ratepayers should receive the benefit of the tax savings Minnegasco actually experiences. The commission finds that the actual taxes paid or payable by Minnegasco related to payroll taxes and employee benefits capitalized must be flowed through in order to provide proper matching of the costs imposed on ratepayers with the costs actually incurred to provide service to those ratepayers. The commission finds that normalization provides no such matching and would require inclusion in rates paid by present customers recovery of taxes Minnegasco did not even pay in 1978. The commission further finds that over time and due to a number of considerations such as construction of plant for expansion or replacement, Minnegasco can continue to defer new amounts and recover more for taxes in each year than it actually pays in that year under the tax normalization method. Further, the commission finds that over an extended period of time, Minnegasco may be being compensated for more federal income taxes than it will ever pay. The commission finds that inflation of construction costs serves to magnify this effect. The commission further finds that the benefit to consumers now is far more valuable than the benefit normalization would have to consumers in later years. Finally, the commission finds that tax normalization assumes that tax circumstances will remain constant and presupposes that the costs of ongoing operations and the cost of construction can be completely separated. The commission finds that both contentions are erroneous.

VII.

Postage and Computer Billing

(A) Staff Position:

Staff recommends that two of Minnegasco's three adjustments to actual 1978 expense for postage and computer billing be disallowed. Staff contends that an adjustment to reflect postage expense for the number of customers at year-end 1978 should be rejected. Minnegasco's adjustment would increase the expenses to year-end levels although the revenues would reflect an average number of customers; i.e., expenses would not be matched by revenues. Additionally, staff points out that the year-end number does not reflect variations in the actual number of customers served throughout one year. Staff notes that only actual expenses incurred would show the interaction between revenues and expenses. Staff contends that this adjustment proposed by Minnegasco destroys the matching concept.

Staff also disallowed an adjustment to postage expense for 1979 projected new customers. Staff witness Petersen testified that it is not a known and measurable change and, accordingly, should not be permitted. Staff disallowed all aspects of both predicted increased expenses and predicted increased revenues flowing from the 1979 customer growth estimate.

Staff did allow an adjustment for increased postal and computer service rates in that it was a known and measurable change and the corresponding revenue effect, being zero, was accordingly taken into account.

(B) Company Position:

Company disputes staff's rejection of ***19** two adjustments relating to annualization of the increase in expenses for customers added in 1978 and the increase in expenses for customers added in 1979. Company contends that customers at year-end 1978 will be billed in 1979 at a known cost per month. Company contends that this is a known and measurable change occurring within twelve months of the end of the test period and is appropriate. Company points out that it has properly annualized postage and computer billing expense for those customers. Company notes that this aspect of the adjustment is the minimum which the commission should reinstate.

Company contends that the other aspects of the disallowed expenses for new customer additions in 1979 should also be allowed. Company contends that it has established the minimum number of new customer additions it expects in 1979, and that that minimum is a known change which is measurable with reasonable accuracy. Company urges allowance of both adjustments rejected by staff.

Commission Findings

The commission finds that staff's recommendation regarding disallowance of two of three adjustments made by Minnegasco to actual 1978 expense for postage and computer billing should be adopted for the reasons set forth in (A) above. The commission finds that the adjustment to reflect postage expenses for the number of customers at year-end 1978 should be rejected because the expenses will not be matched with revenues. Further, the commission finds that the year-end number does not reflect variations in the actual number of customers served throughout one year. The commission finds that only actual expenses incurred would establish the interaction between revenues and expenses to obtain the necessary matching. The commission further finds that the mismatch of revenues and expenses would overestimate expenses and that staff's utilization of actual customer figures would eliminate such overstatement since the actual takes into account the higher year-end number.

The commission finds that staff's disallowance of an amount for postage expenses for 1979 adjustment for new customers is proper because the adjustment does not constitute a known and measurable change and, accordingly, should not be permitted. The commission finds that all aspects, both predicted increased expenses and predicted increased revenues, should be disallowed from the projected 1979 customer figure in that such predictions are unreliable and speculative. The commission finds that staff's allowance of an adjustment for increased postage and computer service rates constitutes a known and measurable change that will be in effect all during 1979, and that the corresponding revenue effect, albeit zero, accordingly being taken into account is totally proper and should be adopted.

VIII.

Property Tax Expense

(A) Staff Position:

Staff recommends that the proposed adjustment for increased 1979 property tax expense should not be allowed. Staff witness Petersen recommended exclusion of this adjustment because it is inconsistent with staff's rate base treatment. Staff points out that the 1979 property tax evaluation is based on property valuations as of January 1, 1979. Hence, this is essentially a year-end 1978 figure and the 1979 property tax valuation will include all of the improvements, additions, and other increases in value as well as all retirements that exist at the end of 1978. Additionally, staff's treatment of property tax expense matches the 1978 tax expense to the 1978 test year. The additional expense relates to a year-end rate base and not to the average 1978 rate base utilized by staff to determine rate base, expenses, and revenues for the test period. Staff notes that including the proposed adjustment without corresponding adjustments to revenues and rate base figures violates the matching principle and overstates expenses accordingly.

Staff contends that a distinction is to be made between Minnegasco's proposed adjustment which results from a change in the quantity and value of property and a property tax expense adjustment that might occur if the tax rate were changed. Changes in tax rates are not affected by difficulties of accurately matching the time frame of revenue, expense, and rate base measurements. The adjustment staff has rejected in this proceeding is one which directly relates to year-end plant and does not in any manner match tax expense with the test year.

(B) Company Position:

Company contends that its property tax adjustment is proper. Company points out that it is based upon actual January 1, 1979, property values as reported to the state department of revenue and reflects only the 1979 property tax increase that arises from increased taxable property values. Company contends that if inconsistency with rate base is the issue regarding staff's disallowance, it is equally true that staff's use of the unadjusted property tax expense for 1978 is not consistent with staff's rate base recommendation. Company points out that the tax for 1978 is based upon Minnegasco's property in service on January 1, 1978, and not the larger average property in service during 1978 reflected in staff's recommended rate base. Indeed, company contends that consistency with rate base should not be at issue in any event. Company contends that property tax is an expense, as is any other expense, and the additional tax to be incurred within twelve months of the end of the test period is known with reasonable certainty. Company maintains that the additional expense will be incurred regardless of the manner in which rate base is determined in this proceeding and that Minnegasco's adjustment should be allowed accordingly.

Commission Findings

The commission finds that staff's recommendation regarding the proposed adjustment for increased 1979 property tax expense should be adopted for the reasons set forth in (A) above. The commission finds that the exclusion of Minnegasco's adjustment is necessary because it is inconsistent with the commission's rate base determinations herein. The commission finds that the 1979 property tax evaluation is based on an evaluation as of January 1, 1979, and utilizes a year-end 1978 figure which is inappropriate for rate-making purposes. ***21** The commission finds that the additional expense related to the proposed adjustment is inconsistent with the average 1978 rate base approved by the commission and that such an adjustment would distort the matching of rate base, expenses, and revenues for the test period. Further, the commission finds that Minnegasco made no attempt whatsoever to make corresponding adjustments to revenues and rate base figures which totally violates the matching principle and overstates expenses accordingly. The commission finds that Minnegasco's adjustment does not involve the change in tax rates which would not necessarily distort the matching of revenue, expense, and rate base determinations. The commission further, and more importantly, finds that the treatment accorded property taxes herein matches the 1978 tax expense to the 1978 test period.

IX.

Depreciation and Amortization Expense

(A) Staff Position:

Staff contends that the company's adjustments to 1978 test year for depreciation and amortization should be disallowed. Staff contends that the adjustments would include a full year's depreciation for all plant in service as of December 31, 1978, and a predicted depreciation for plant added during 1979.

Staff witness Petersen testified that staff is utilizing an average 1978 rate base and that a portion of the proposed adjustment restates depreciation and amortization at year-end levels. Witness Petersen noted that use of a year-end level of depreciation and amortization would be inconsistent with staff's use of average rate base and would, consequently, violate the matching principle. The portion of the adjustment relating to the 1979 projected expenses is in staff's view not known and measurable, and rejection of this portion of the adj stment is required for consistency with staff's rate base.

(B) Company Position:

Company contends that its adjustment is proper and that staff witness Petersen's recommendation does not recognize depreciation expense which Minnegasco will incur during 1979. Company witness Swetman testified that the depreciation adjustment disallowed by staff is in fact necessary to properly match revenues and expenses. The depreciation adjustment includes two portions: one required in company's view to reflect a full year's depreciation on actual plant in service at the end of 1978, and one to reflect depreciation on 1979 net additions to plant. Company maintains that the first portion of the adjustment is clearly known and measurable. Further, company contends that the second portion, depreciation expense related to net plant additions in 1979, is known with reasonable certainty since the depreciation expense is merely a calculation utilizing actual depreciation rates. As a result, company maintains that its adjustment is proper and should be allowed by the commission.

Commission Findings

The commission finds that staff's recommendation regarding depreciation and amortization expense should be adopted for the reasons set forth in (A) ***22** above. The commission finds that the adjustments would allow inclusion as additional costs a full year's depreciation for all plant in service as of December 31, 1978, and a predicted depreciation for plant added during 1979. The commission finds that as a result of the commission's rate base determinations herein, staff's recommendation fully matches depreciation expense and plant in service and properly reflects plant-related costs. The commission further finds that that portion of the adjustment relating to the 1979 projected expenses is not a known and measurable change. As a result, 1979 projections and estimates should be disallowed.

X.

Uncollectible Accounts

(A) Staff Position:

Staff contends that company's proposed adjustment for uncollectible accounts expense should be disallowed. Staff points out that the proposed adjustment represents Minnegasco's prediction that increased revenues resulting from the aggregate of four other proposed adjustments normalizing actual 1978 figures would result in a proportionate increase in uncollectible accounts expense. The four proposed adjustments thus incorporated in the uncollectible accounts adjustment are normalization of 1978 weather, reduced sales due to conservation, annualization of current rates, and predicted increase in customers. Consequently, in order to accept the uncollectible accounts ajustment, the commission must also accept all of these adjustments on which the uncollectible accounts adjustment is based.

Staff witness Petersen recommends not allowing the adjustment to uncollectible accounts because it is too speculative and is not a known and measurable change. Staff witness Petersen testified that no fixed relationship between the amount of revenues and uncollectible accounts has been established by Minnegasco. Staff cited, for an example, that the increased revenues produced by an increased number of customers might not lead to the same amount of uncollectible accounts as increased revenues due to increased usage per customer under increased rates. Staff witness Petersen indicated that other factors might affect the uncollectible accounts amount such as changes in customer income and the availability and use of assistance programs for fuel bills by customers. Additionally, staff contends that the adjustment is not known and measurable in that it is based in part on other proposed adjustments which are not known and measurable such as the conservation adjustment and the predicted customer growth.

Staff points out that company witness Swetman attempts to justify the adjustment in that the amount of increased uncollected accounts will be at least equal to the amount included in Minnegasco's proposed adjustment. Staff notes that Minnegasco has attempted to utilize this argument in certain of their other adjustments and it should be rejected. If an adjustment is not known and measurable, it should not be allowed because it is speculative and not subject to verification. Minnegasco's contention that if attempts to estimate and project are made by Minnegasco, the adjustments resulting therefrom should be allowed. Staff finds this to be utenable and erroneous.

***23 (B) Company Position:**

Minnegasco contends that its adjustment for uncollectible accounts expense should be allowed Company witness Swetman testified that in 1978, the relationship between uncollectibles and revenues was .314 per cent. The uncollectible accounts adjustment was calculated utilizing the same factor applied to the increase in test-year revenues based only upon present rates.

Company contends that staff witness Petersen's disallowance of the adjustment because it is not known and measurable is improper and incorrect. Company witness Swetman explained in detail the historical information upon which he based his adjustment and that his analysis of past year's experience establishes the sharply increasing trend for uncollectible accounts. As a result, company contends that its adjustment is conservative and, like its inflation adjustment, reflects a known minimum amount of losses which will occur. Accordingly, the company urges the commission to adopt its adjustment and reject staff's disallowance.

Commission Findings

The commission finds that staff's recommendation regarding uncollectible accounts should be adopted for the reasons set forth in (A) above. The commission finds that Minnegasco's proposed adjustment represents Minnegasco's prediction that increased revenues resulting from the aggregate of four other proposed adjustments normalizing actual 1978 figures would result in a proportionate increase in uncollectible accounts expense. The commission finds that the adjustment is too speculative and is not a known and measurable change. The commission finds that Minnegasco has not established any fixed relationship between the amount of revenues and uncollectible accounts. The commission finds that other factors may affect the uncollectible accounts amount such as changes in customer income and the availability and use of assistance programs for fuel bills by customers. The commission finds that the adjustment is not known and measurable and that it is based in part on the other adjustments which this commission has hereinafter found to also be not known and measurable. The commission finds that Minnegasco's contention in this and other areas regarding its adjustment as being a minimum although not being known and measurable is without merit. The commission finds that an adjustment that is not known and measurable and not subject to verification is speculative and should not be allowed.

XI.

Advertising Expense

(A) Staff Position:

Staff recommends that Minnegasco's claimed expense for institutional and promotional advertising should be disallowed. Staff witness Jorgensen testified that these types of advertising were designed to increase revenues, primarily benefit the stockholder and not the consumers, and, consequently, stockholders rather than consumers should pay for such expenses. Staff witness Jorgensen permitted Minnegasco to include in its cost of service the expenses relating to conservation and safety advertising. Staff contends that ***24** Minnegasco's basic approach to advertising and advertising expense is erroneous. Staff notes that company witness Swetman contends that promotional advertising does not benefit Minnegasco at all. Staff finds this to be an untenable position since advertising causes increased revenues which are a clear benefit to Minnegasco. Further, staff notes that company witness Swetman could not offer a definition of promotional advertising even though he utilized that terminology in his presentation.

As to the February, 1979, Department of Energy letter that company contends supports its position, staff notes that it is directed toward attracting new heating customers while company's advertising is not addressed to attracting new heating customers but rather to encouraging the use of small gas appliances. Additionally, staff notes that the saturation level in areas served by Minnegasco is already in the upper 90 per cent range.

Staff points out that company witness Swetman and staff witness Jorgensen do not have disagreement over there being no significant difference between what Minnegasco had classified as load factor advertising and what Minnegasco had classified as promotional advertising. Consequently, staff contends that staff witness Jorgensen's reclassification of load factor advertising as promotional advertising is totally appropriate. The advertising in question was intended to encourage retention of gas appliances and encourages purchases of new gas appliances. Staff witness Jorgensen noted that while under certain circumstances increased usage might improve load factor, it would also and in every case tend to increase revenues. In light of the wide dissemination of such advertising, staff witness Jorgensen found that this would be a certain benefit to shareholders and, consequently, those shareholders should pay the related expense associated therewith.

Staff further points out that there is a question regarding the seriousness with which Minnegasco actually views the need to improve its load factor. Staff notes that Minnegasco has not added any large industrial interruptible customers in several years as a matter of principle and as a result of a gentleman's agreement among Northern distribution groups not to serve such industrial customers. Further, company witness Schroedermeier testified that it was not Minnegasco's policy to encourage consumers to use more gas in the summer than in the winter.

Staff also notes that Minnegasco did not present any specific information about its load factor, the goals that it set for improving its load factor, or how the denominated load factor advertising would serve to achieve those goals. Staff contends that this establishes that the claimed benefits to load factor from such advertising are even less certain and may not materialize.

Finally, staff contends that institutional advertising aimed at informing the public about Minnegasco and about natural gas, likewise, does not contain any message that concretely benefits consumers. Consequently, consumers should not be required to pay for advertising aimed merely at encouraging and fostering an image and a general public awareness of Minnegasco. Staff concludes that the disallowances it recommends are necessary in that they are not related to the provision of adequate, reliable, and safe gas service.

***25 (B) Company Position:**

Company contends that staff witness Jorgensen's adjustments are improper. Company contends that Miss Jorgensen improperly reclassified load factor advertising to promotional advertising and thereafter disallowed the entire amount. Company witness Swetman testified that load retention was an appropriate subject for load factor advertising. Company classified as such the type of advertising designed to maintain gas service and replace old gas appliances with new appliances. Company notes that staff witness Jorgensen concurred. Company witness Swetman further testified that encouraging customers to purchase gas appliances initially and replace existing appliances with gas appliances were two primary ways of maintaining or improving load. Company contends that while Miss Jorgensen disagrees with Mr. Swetman's analysis, the example Miss Jorgensen utilized of appropriate load factor advertising was erroneous and inappropriate.

Company maintains that staff witness Jorgensen was either unfamiliar with the nature of load factor advertising or was merely predisposed to disallow such advertising.

Company also disputes the disallowance of the other portion of promotional advertising and the disallowance of institutional advertising Company witness Swetman testified that promotional advertising is beneficial to customers because it informs them that natural gas is currently the most cost efficient fuel available. Further, company witness Swetman testified that institutional advertising is a necessary prerequisite to the effectiveness of all other advertising done by Minnegasco. As a result, company maintains that the evidence clearly establishes that Minnegasco's advertising serves to benefit its customers and is in the public interest. Minnegasco urges the commission to allow the entire amount of its requested advertising expense.

(C) ACORN Position:

South Dakota ACORN contends that staff's position should be adopted by the commission regarding disallowance of certain advertising expenses.

Commission Findings

The commission finds that staff's recommendations regarding Minnegasco's claimed advertising expense should be adopted for the reasons set forth in (A) above and on the basis of South Dakota ACORN's recommendations set forth in (C) above. The commission finds that staff properly determined the amount of advertising expenses which were expended upon advertising designed to increase revenue and to benefit stockholders, not ratepayers. The commission finds that staff's inclusion of load factor advertising into the classification of promotional advertising is totally proper. The commission finds that all such promotional advertising is of benefit primarily, if not entirely, only to shareholders and that, as a result, those shareholders should be required to pay the related expenses associated therewith. The commission finds that promotional advertising benefits Minnegasco and that Minnegasco's contention to the contrary is totally without merit. The commission finds that, additionally, institutional advertising aimed at informing the public about Minnegasco and about the natural gas ***26** industry does not serve to benefit consumers. The commission finds that consumers should not be required to pay for any advertising aimed merely at encouraging and fostering an image and a general public awareness of Minnegasco.

The commission finds that any claimed benefit to consumers that Minnegasco asserts as a result of its institutional and promotional advertising either does not exist at all or is so tenuous and speculative that those consumers should not be required to pay for such advertising. Minnegasco has provided this commission with absolutely no substantiation or proof of benefits to consumers accruing from any of its institutional and promotional advertising. The commission finds that all such advertising is not necessary or required for the rendition of safe, adequate, and reliable gas service.

On the other hand, the commission finds that staff's allowance of advertising expenses relating to conservation and safety do benefit consumers and, consequently, should be borne by the consumers. The commission finds that the allowance of such expenses in consumers' rates is proper in that there is direct benefit to consumers from such advertising.

XII.

Dues

(A) Staff Position:

Staff contends that the commission should not allow inclusion of the expenses associated with Minnegasco membership in the American Gas Association and in other organizations. Staff witness Jorgensen testified that AGA's basic orientation is toward activities that benefit the gas industry and do not necessarily benefit consumers. Staff witness Jorgensen noted that while only a small portion of lobbying expenses are reported under the federal lobbying laws, this fact establishes nothing regarding who benefits from the remainder of AGA's activities. Staff contends that AGA's informational and educational activities and its studies, analyses, and other information gathering activities are probably oriented toward promoting the gas industry. As to research, staff contends that no information was supplied regarding who controls the direction of research, how projects are chosen and funds are allocated, or who obtains the benefits from successful research results. Staff witness Jorgensen testified that the research may be used for promotion of the industry with no benefit to the consumer. Additionally, Miss Jorgensen testified that consumers pay for new technologies eventually when they come on line and are used and useful in rendering gas service.

Staff notes that its recommendation in no manner prohibits Minnegasco from participating in any AGA activities, but rather, merely requires those who benefit from such activities—i.e., Minnegasco's stockholder—to pay for those activities.

Staff contends that other dues expense for other organizations should also be disallowed. Staff notes that these dues are for memberships primarily in Minnesota organizations and have not been shown to in any manner be necessary for the rendition of safe, adequate, and reliable service to South Dakota consumers. Staff notes that company witness Swetman did not know or have knowledge of how many meetings the ***27** Employers Association of Greater Minneapolis had had, or who from the company had attended such meetings. Further, company witness Swetman had never personally received information from the Upper Midwest Council. Staff concludes that while the amounts involved are small, the benefits to South Dakota consumers are so speculative and unsubstantiated that they should not be borne by the ratepayers.

(B) Company Position:

Company points out that both staff and company agree that the $87 expended by the AGA for federal lobbying should be excluded as an allowable expense. Company disputes staff witness Jorgensen's disallowance of the remaining AGA dues. Company witness Swetman testified regarding the activities of AGA and provided in company's view detailed information of why AGA's research and other activities benefit ratepayers. Company contends that staff witness Jorgensen's total disallowance of AGA dues is arbitrary and unfounded. Company maintains that the AGA dues claimed in its filing are necessary, reasonable, and prudent in Minnegasco's gas utility business and provide a direct benefit to consumers. As a result, the dues should be included.

Company points out that in its Minnesota rate proceeding presently on rehearing before the Minnesota Public Service Commission, the Minnesota energy agency responsible for encouraging thrift in the use of energy and maximizing energy-efficient systems testified that there were overall ratepayer benefits accruing from AGA research.

As to other dues, company contends that they are appropriate and should be allowed. Company witness Swetman testified that specific benefits to South Dakota customers accrue from the memberships in these organizations. Further, company witness Fleer testified that Minnegasco's management function is system-wide and any savings achieved at the corporate level are shared proportionately in each of Minnegasco's state jurisdictions. Company contends that the memberships in these various organizations are beneficial to South Dakota ratepayers and should be allowed.

(C) ACORN Position:

ACORN contends that staff's position should be adopted. It is the position of ACORN that company should not be permitted to impose upon its customers charges arising out of memberships to various organizations. ACORN contends that there has been no showing that membership expenses are in any manner used and useful in providing safe, reliable, and adequate natural gas service to customers.

Commission Findings

The commission finds that staff's recommendation regarding dues should be adopted for the reasons set forth in (A) above and on the basis of South Dakota ACORN's recommendation set forth in (C) above. The commission finds that staff's disallowance of American Gas Association and other organization dues is entirely justified and is proper. The commission finds that AGA's basic orientation is toward activities that benefit the gas industry and do not necessarily benefit consumers. The commission finds that while only a ***28** small portion of lobbying expenses as reported under federal lobbying laws exist, this fact establishes nothing regarding who benefits from the remainder of AGA's activities. The commission finds that the informational and educational activities and AGA's studies, analyses, and other information gathering industries are probably oriented toward promoting the gas industry as opposed to benefiting consumers in any direct or concrete manner. The commission finds that with respect to research, Minnegasco has failed to provide any information regarding who controls the direction of research, how projects are chosen and funds are allocated, or who obtains the benefits from successful research results. The commission finds that research may be used for promotion of the industry with no benefit to the consumers. Additionally, the commission finds that consumers ultimately pay for new technologies when they come on line and are used and useful in rendering gas service to those consumers. The commission finds that Minnegasco is in no manner precluded from participating in any AGA activities, but rather, may not recover for the dues associated therewith from its ratepayers since the ratepayers have no benefit from such expenditures.

The commission finds that the other dues expense disallowances recommended by staff are totally proper. The commission finds that those dues are for memberships primarily in Minnesota organizations and have not been shown to in any manner be necessary for the rendition of safe, adequate, and reliable service to South Dakota consumers. The commission finds that Minnegasco was uninformed regarding the purpose and functions of many of the organizations it attempted to have ratepayers pay for in this proceeding. The commission finds that the benefits to South Dakota consumers are so speculative, unsubstantiated, remote, or not existent, that those expenses should not be borne by ratepayers.

XIII.

Contributions

(A) Staff Position:

Staff contends that commission should disallow expenses related to charitable contributions made by Minnegasco. Staff notes that the expenditures are not part of normal business expenses. Minnegasco is in the business of providing distribution of natural gas and in staff's view is not in the business of upgrading the level of social services by making involuntary collections from its customers. Staff notes that while company witness Swetman testified that communities practically demand contributions to be made, company witness Swetman would not say whether Minnegasco would make the contribution if it were not reimbursed for same in the rates it charges to customers. Staff contends that while company witness Swetman attempted to establish the minimal effects such contributions have on ratepayers, the aggregate amounts contributed provide significant support to the organizations it selects. Staff notes that these organizations may very well be organizations objected to by certain individual or groups of ratepayers. Staff contends that this is discriminatory and should not be permitted. Additionally, staff contends that such contributions are not necessary in the provision of adequate, reliable, and safe gas service.

***29 (B) Company Position:**

Minnegasco contends that its contributions should be allowed in the rates set in this proceeding. Minnegasco witness Swetman testified that communities place an obligation on business for support, communities benefit in general and those communities are the customers of Minnegasco, and all products a consumer purchases include a portion for contributions by any firm. Company witness Swetman testified that a committee of the board of directors makes the decision on which organizations will receive Minnegasco contributions. Company witness Swetman testified that the committee generally does not authorize contributions to special interest organizations such as neighborhood groups or local churches but rather to organizations with communitywide support such as United Way. Company witness Swetman noted that these organizations with wide support eliminate involuntary contributions by ratepayers in that that support is broad based and across the board. Company witness Swetman testified that consumers benefit as a result of the community environment wherein Minnegasco operates. Minnegasco argues that its charitable contributions expense should be allowed and is beneficial to ratepayers.

(C) ACORN Position:

ACORN recommends that commission staff's position be adopted. While ACORN recognizes that contributions to organizations within communities are beneficial to those communities, ACORN contends that that in no manner establishes that the expenditures are used and useful for the provision of natural gas service that is both safe and economical. Further, ACORN points out that certain consumers may very well be offended at the types of organizations selected by Minnegasco for contributions and the expenses related thereto should not be borne by any consumers.

Commission Findings

The commission finds that staff's recommendation regarding charitable contributions should be adopted for the reasons set forth in (A) above and on the basis of South Dakota ACORN's recommendation set forth in (C) above. The commission finds that these expenditures are not part of normal business expense and that Minnegasco is in the business of providing distribution of natural gas and has a monopoly over such distribution. The commission finds that as a result, ratepayers should not be required to pay the expenses associated with the organizations selected by Minnegasco to receive its beneficence and that any such expenses should be provided by Minnegasco's own largess, not through involuntary collections from its ratepayers. The commission totally rejects company's position that because the contributions reflect a minimal amount paid by each ratepayer over the course of the year the ratepayers should provide for such expenses in their rates. The commission finds that the aggregate amounts contributed by Minnegasco to particular organizations provide significant support to those organizations it selects. Further, such organizations may well be organizations objected to by certain individuals or groups of ratepayers. The commission finds that this is discriminatory and should not be permitted. Further, the commission finds that such contributions are not necessary for the provision of adequate, safe, and reliable gas service to consumers. Finally, the commission finds that simply because the cost to each consumer is minimal, this fact in no manner justifies inclusion in Minnegasco's cost of service a provision for any expenses which are not otherwise justified or proper.

XIV.

Inflation Adjustment

(A) Staff Position:

The commission staff recommends that Minnegasco's proposed general inflation adjustment be disallowed in that it is not a known and measurable change. The inflation adjustment proposed by Minnegasco is based upon company witness Swetman's estimated 1978 inflation rate at 8 per cent and 1979 inflation rate of 12 per cent. Staff contends that contrary to Mr. Swetman's position, the 1979, inflation adjustment is calculated at 12 per cent, not 6 per cent. Staff notes that the calculation of the 6 per cent amount is applied throughout 1979. Hence, the proposed adjustment as calculated reflects an average of 6 per cent over the year 1979; i.e., an inflation rate of 12 per cent for the year. Staff contends that this is contrary to the national policy regarding anti-inflation goals which company witness Swetman invoked in portions of his testimony.

Staff witness Petersen recommended the adjustment be rejected because it is not known and measurable. The company presented two types of purported bases as justification. First was a list of 60 assorted items purchased in early 1978 and again in late 1978. Secondly, reference was made to the consumer price index and the producer price index. However, Minnegasco in staff's view has not been able to relate the expenses actually incurred and included to the proposed justifications for its inflation estimates.

Staff points out that in Minnegasco's 60-item list, the inclusion and selection were based entirely on the criteria of whether Minnegasco happened to buy the items one in early 1978 and once again in late 1978. Company witness Swetman was not able to provide information as to what part of the total these items represented. Company witness Swetman testified that he did not know whether discounts from quantity purchases were reflected in the list and company made no effort to show that the list was statistically representative of items whose expense the list was supposed to demonstrate. Further, Minnegasco did not show that the list was representative or accurate for other major expense items covered by the proposed adjustment.

Staff witness Petersen testified that the consumer price index and the producer price index are not useful to measure the impact of inflation on a utility operation. Both indexes are fixed-weight indices of particular prices paid by a specific population for a particular bundle of goods and services. Both the 8 per cent inflation figure for 1978 and the 12 per cent for 1979 are presented as the result of an estimation of inflation for the periods described. Staff contends that this type of judgmental approach to an inflation adjustment which could be approached more precisely and exactly is not acceptable in that it does not in any manner constitute a known and measurable ***31** change. Staff points out that Minnegasco has the opportunity to reflect changes in its costs by specifically identifying cost increases or decreases in its pro forma adjustments rather than attempting to lump all expenses together and applying indices which are not even applicable to utility operations.

(B) Company Position:

Minnegasco contends that its inflation adjustment is reasonable and conservative. Minnegasco points out that it has thousands of small purchases and transactions which cannot be individually tracked. For those particular transactions, Minnegasco has estimated the expected rise in the general level of prices and applied that to the total of the miscellaneous yet numerous items. Minnegasco contends that the assumptions and empirical data upon which it relied in making this estimate reflect a known minimum increase in prices which will most definitely be experienced. Minnegasco contends that disallowing such a known, minimum level of inflation is illogical and contrary to established test-year principles. Minnegasco recognizes that the exact dollar amount of inflation cannot be adjusted for, but contends that its inflation adjustment reflects a minimum known change. Minnegasco contends that the commission should allow its adjustment accordingly.

Additionally, Minnegasco contends that its inflation adjustment is not based upon the consumer price index, but rather is based upon actual experience in 1978 and a reasonable projection of the average level of inflation Minnegasco will experience in 1979. Minnegasco contends that its witness Swetman provided a representative sample of goods and services purchased by Minnegasco in early 1978 and again in late 1978. Minnegasco points out that the overall weighted net increase in prices for these items was 8.7 per cent which compared favorably with the level of increase in both the consumer price index and the producer price index. Minnegasco contends that its adjustment is based upon Minnegasco's actual experience in 1978 and that allowance of such an adjustment is fully consistent with South Dakota judicial precedent.

Commission Findings

The commission finds that staff's recommendation regarding Minnegasco's general inflation adjustment should be adopted for the reasons set forth in (A) above. The commission finds that Minnegasco's proposed inflation adjustment is contrary to the national policy regarding anti-inflation goals. The commission finds that Minnegasco's adjustment is not known and measurable. The commission further finds hat the two purported bases for justification advanced by Minnegasco are without merit. The commission finds that the list of 60 assorted items purchased in early 1978 and again in late 1978 do not constitute a representative list and do not in any manner provide a reliable standard or guideline by which this commission can evaluate the reasonableness of company's general inflation adjustment. The commission further finds that the second justification based upon the consumer price index and the producer price index have little, if any, merit.

The commission finds that Minnegasco's 60-item list was based entirely on the criteria of whether Minnegasco happened to buy the items once in early 1978 and once again in late 1978. ***32** Further, the commission finds that Minnegasco was not able to provide any information as to what part of the total these items represented in its general inflation adjustment.

Minnegasco was unable to supply the quantities purchased during the test year for any of the 60 items. Additionally, Minnegasco did not know whether discounts for quantity purchases were reflected in the list and made no effort to establish that the list was statistically representative of all items whose expense the list was supposed to demonstrate. Finally, the commission finds that Minnegasco did not establish that the list was representative or accurate for other major expense items covered by the proposed adjustment.

The commission further finds that the consumer price index and the producer price index are not useful to measure the impact of inflation on a utility's operations. The commission finds that both indexes are fixed-weight indices of particular prices paid by a specific population for a particular bundle of goods and services not necessarily related to utility operations. The commission finds that the 8 per cent inflation figure for 1978 and the 12 per cent inflation figure for 1979 are presented as a result of an estimation of inflation for the periods described. The commission rejects Minnegasco's contention that its 6 per cent rate for 1979 and finds that it actually represents a 12 per cent rate for 1979. The commission finds that this type of judgmental and estimated approach to an inflation adjustment which could be approached more precisely and exactly if Minnegasco had so desired is not acceptable in that it does not in any manner constitute a known and measurable change.

The commission finds that it will recognize known and measurable changes which will occur to Minnegasco but the commission refuses to accept speculative, unsubstantiated, and arbitrary inflation adjustments which in no manner relate to, or are representative of Minnegasco's actual experience or to Minnegasco's operations. The commission finds that Minnegasco failed or refused to specifically identify in its pro forma adjustments any such known and measurable changes but rather merely attempted to lump all expenses together and apply indices and criteria which are unrepresentative or inapplicable to its utility operations.

XV.

Adjustment for Current Federal Income Tax

(A) Staff Position:

Staff reconstructed interest expense per books to include only that portion related to investment and compared that to pro forma interest expense related to investment to derive the income tax effect of interest expense annualization. Company witness Swetman criticized staff's methodology. Staff contends that that criticism is without merit and is unjustified. Company witness Swetman proposed an income tax adjustment for interest expense annualization which represents the difference between pro forma interest related to investment and the total interest expense appearing on the company's books. Staff contends that the booked expense includes not only interest on long- and short-term debt but other interest expenses such as interest on customer deposits and customer refunds. Staff noted that company witness ***33** Swetman agreed that the purpose of the interest adjustment was to adjust to an interest figure based upon investment in South Dakota utilizing the interest rate that is in Minnegasco's filing. However, staff contends that interest items other than interest on long- and short-term debt are unrelated to this purpose. As a result, the income tax adjustment for interest expense annualization should be based upon staff's method of comparing pro forma to actual interest on only long- and short-term debt and should not be based upon Minnegasco's method.

In developing the investment base from which pro forma interest was derived, staff included construction work in progress not included in staff's average rate base. Minnegasco was critical of such inclusion of CWIP contending that it should not be utilized without a corresponding provision for deferred income taxes. Staff, however, notes that inclusion of CWIP in the investment base is appropriate and compatible with its flow-through recommendations and that not utilizing CWIP in the calculation would result in Minnegasco normalizing the tax benefit of interest expense.

(B) Company Position:

Company concurs, in principle, with staff's adjustment for interest expense annualization, but contends that the adjustment contains errors. Company witness Swetman testified that staff included staff's proposed CWIP figure with its average rate base in its calculation, the effect of which is to improperly give current ratepayers the tax benefit of an interest cost which will be borne by future ratepayers. Further, company witness Swetman testified that staff failed to use the proper actual interest expense figure as found in company's filing. As a result of these asserted erros, Minnegasco urges adoption of its recommendation.

Commission Findings

The commission finds that staff's interest expense adjustment is proper and should be adopted for the reasons set forth in (A) above. The commission finds that the booked expense includes not only interest on long- and short-term debt but other interest expense such as interest on customer deposits and customer refunds. The commission finds that interest items other than interest on long-and short-term debt are unrelated to the purpose of the interest adjustment which is to establish an interest figure based upon investment in South Dakota. The commission finds that, as a result, the interest adjustment proposed by Minnegasco should be based upon staff's methodology of comparing pro forma to actual interest on long- and short-term debt. The commission finds that staff's recommendation of including CWIP in the investment base from which pro forma is derived flows through the tax benefits experienced by the company to current ratepayers. The commission finds that this is the identical issue relating to the propriety of flowing through deferred income taxes related to capitalized payroll taxes and employee benefits. The commission finds that current ratepayers shojld be given the ratepayers should be given the avoided by Minnegasco.

XVI.

Weather Normalization

***34 (A) Staff Position:**

Minnegasco proposed a weather adjustment to its 1978 actual figures to adjust to normal levels of gas usage. Staff agrees in principle that such an adjustment is appropriate, however, staff contends that Minnegasco has made a serious error in its method of calculating normal weather. Minnegasco excluded all actual 1978 weather data in calculating its 20-year normal. Staff witness Black testified that the normals should be based upon the most currently available data and utilized in his weather adjustment a normal including 1978 figures.

Staff contends that company witness Pooler could not adequately explain the justification for Minnegasco's exclusion of the 1978 data. Staff contends that Minnegasco clearly had sufficient and ample information to determine the 1978 weather normal figure if it had made any effort whatsoever to do so.

Staff contends that the fundamental difficulty with Minnegasco's position is that Minnegasco apparently excluded 1978 data simply becau e it was colder than normal. Staff notes that Minnegasco's exclusion was not based upon any question of accuracy of raw data or of sampling technique but merely was based upon the fact that 1978 was a colder than normal year. Staff further notes that while Minnegasco maintains that it would act in the same manner regarding an abnormally warm year, the record reflects that a rate increase in Minnesota filed in October of 1977 was justified in part by lower revenues due to abnormally warm weather in 1977. Consequently, staff contends that it is clear that Minnegasco's policy appears to be one of including abnormally warm years in its normal and excluding abnormally cold years in its normal for rate case filing purposes. Staff contends that this is neither reasonable nor acceptable for adjusting the weather to normal.

Staff contends that its revised weather normal should be adopted. Staff witness Black testified that a number of related adjustments flow from the change in the weather normal. Hence, for purposes of consistency, all adjustments proposed by staff for weather normalization, annualized purchased gas costs, annualized revenues, and annualized LPG expense should be, accordingly, adopted.

(B) Company Position:

Minnegasco recognized the unusually cold weather existent in 1978 and therefore normalized test-year weather by decreasing revenues accordingly. Minnegasco contends that its use of a 20-year normal ending prior to the commencement of the test period is based upon logic, judgement, years of forecast experience, and the best basis of a 20-year normal available. Minnegasco contends that its adjustment should be approved by the commission.

Commission Findings

The commission finds that staff's recommendation regarding weather normalization should be adopted for the reasons set forth in (A) above. The commission finds that on the basis of this record, some type of adjustment to recognize normal levels of gas usage should be made. The commission finds that Minnegasco's exclusion of all 1978 weather data in calculating its 20-year normal is arbitrary and wholly unsupported. The commission finds that the ***35** normals should be based upon the most currently available data in deriving the normal and that staff's recommended weather adjustment including 1978 data is totally proper and presents a representative level of gas usage. The commission finds that Minnegasco's attempt to exclude cold years in providing a normal and its record including warm years in deriving its normal is not only unwarranted but verges on incredulity.

The commission further finds that no circulatity of statistics would result by using the 1978 actual weather conditions simply because of the 1978 test year selected by both staff and Minnegasco.

The commission finds that staff's adjustments which are based upon its normal are proper and should be adopted. The commission finds that staff's weather normalization, annualized purchased gas costs, annualized revenues, and annualized LPG expense are properly determined and should, accordingly, be adopted.

XVII.

Conservation Factor

(A) Staff Position:

Staff recommends that the commission disallow company's adjustment for increased conservation of 3.5 per cent because it is not known and measurable. Minnegasco's proposed adjustment predicts lower usage per customer in 1979 due to added conservation with the consequent need for obtaining revenues for increased rates. However, staff witness Black found that Minnegasco failed to make any serious attempt to quantify the impact of conservation in the twelve months following the test period. Staff points out that Minnegasco's method for deriving the 3.5 per cent figure was simply to note a historical decline in usage per customer of 3.5 per cent for 1978 over the previous year and to merely assume that that rate would continue. Staff contends that Minnegasco made no attempt whatsoever to examine the causes or mechanisms of conservation and provided no information, historical or otherwise, re arding a consistent trend.

Further, commission staff finds that Minnegasco's purported linear regression equation is unsubstantiated and without foundation because of use of varying a data base. Staff points out that there are finite steps consumers can take to conserve gas such as replacing inefficient applicances, adding insulation, and turning thermostats down a certain number of degrees. Staff notes that at some point, most consumers will have done all that is possible and a saturation point has or will be reached. Without an evaluation of the various types of customer activities that produce conservation, it is staff's view that Minnegasco cannot accurately predict how much future conservation will occur.

Additionally, staff contends that the accuracy of the 3.5 per cent estimate is highly questionable in light of the historical declining rate of conservation. Staff concludes that Minnegasco has simply not adequately supported its estimated conservation adjustment and, therefore, the adjustment should be rejected by the commission.

(B) Company Position:

Minnegasco contends that the 4.5 per cent reduction in heating gas used per residential customer for the calendar ***36** year 1978 and the 4.4 per cent reduction in annual consumption for firm gas customers between 1977 and 1978 support its claimed adjustment in this proceeding. Minnegasco contends that the trend is continuing and that its requested 3.5 per cent adjustment is conservative and should be allowed. Company contends that staff witness Black did not do an independent determination of the effects of conservation and did not form a valid conclusion regarding such conservation. Minnegasco contends that staff's recommendation fails to adjust for a known minimum and that staff's disallowance should be rejected by the commission.

Additionally, Minnegasco contends that staff relied upon incorrect data to support staff's position that the effects of conservation were declining and, consequently, Minnegasco's adjustment was unsupported. Minnegasco claims that the correct data establishes that there is a definite and consistent trend and that that trend is far in excess of Minnegasco's 3.5 per cent adjustment.

Commission Findings

The commission finds that staff's recommendation regarding disallowance of Minnegasco's adjustment for increased conservation of 3.5 per cent should be adopted for the reasons set forth in (A) above. The commission finds that Minnegasco failed to make any serious attempt to auantify the impact of conservation in the twelve months following the test period. The commission finds that Minnegasco's method for deriving the 3.5 per cent figure was simply to note a historical decline in usage per customer of 3.5 per cent for 1978 over the previous year and to merely assume that that rate would continue. The commission finds that Minnegasco made no attempt whatsoever to determine let alone examine the causes or mechanisms of conservation and that Minnegasco provided no information, historical or otherwise, regarding a consistent trend. The commission finds that Minnegasco's purported linear regression equation is unsubstantiated and without foundation because of Minnegasco's use of varying data bases and improper methodology. The commission finds that there are a finite number of steps consumers can take to conserve gas and that at some point most consumers have done all that is possible. As a result, a saturation point has or will be reached and absent an evaluation of the various types of customer activities that produce conservation, the commission finds that there is no way to accurately predict how much future conservation will occur. The commission finds that Minnegasco's 3.5 per cent estimate is not only not a known and measurable change but highly questionable in light of historical declining rates of conservation. The commission finds that Minnegasco has wholly failed to support its estimated conservation adjustment and, accordingly, that adjustment should be rejected. The commission finds that Minnegasco's failure to quantify the effects in conjunction with a delineation of the type of conservation the adjustment purports to measure renders Minnegasco's adjustment without merit.

The commission finds that such quantification is necessary to determine the degree of energy saving equipment currently in existence on Minnegasco's system and the degree to which its present customers have already achieved a level of gas usage reflecting conservation. ***37** The commission finds that staff's contention that conservation adjustments are a relatively recent phenomenon and that no witnesses, be it for commission staff or utilities, have and much experience in dealing with such an adjustment has merit. This is confirmed in this proceeding by both staff witness Black having to eyeball the data as well as company witness Schroedermeier having to secure his information through Kiwanis and church meetings. The commission finds that there can be no serious question regarding the failure of Minnegasco to provide any substantiation or justification for its conservation factor.

XVIII.

Customer Growth

(A) Staff Position:

Staff contends that Minnegasco's proposed adjustment for customer growth should be disallowed because it is not a known and measurable change. Staff points out that Minnegasco's primary basis for deriving its customer growth adjustment is to estimate new housing starts by talking to bankers, construction officers, and others. However, company witness Schroedermeier did not participate in any survey and did not derive any information about South Dakota and its situation. Merle Jansen, Minnegasco's South Dakota manager, prepared a report in August of 1978 which was the basis for company witness Schroedermeier's determination. However, and inexplicably, company witness Schroedermeier changed the South Dakota office's estimate and made numerous reductions including four new large and small volume interruptible customers. Staff notes that company witness Schroedermeier did not point to any documentations establishing how Minnegasco had derived its estimate of 825 new residential housing starts for 1979 from either 900 or 880 as an overall estiamte for firm customers. Additionally, staff criticizes Minnegasco's linear regression analysis for inadequate data.

Staff further notes that Minnegasco has been inconsistent regarding customer increases between the present rate filing and the proceeding in PUC Docket F–3237 wherein Mr. Bjorklund, a witness for Minnegasco, testified on May 21, 1979, that new connections would be at the same level, companywide and in South Dakota as in 1978 which was approximately 1,000. The PUC Docket F–3237 dealt with elimination, in whole or in part, of master metering in South Dakota.

Further, staff contends that further uncertainty and doubt is cast upon Minnegasco's customer growth estimate when predicted and actual customer growth is compared. Minnegasco forecast fewer customers for January, 1979, than were actually on-line at December 31, 1978. Staff notes there were similar underestimates in subsequent months. Staff notes that company witness Pooler provided information which points out the errors and the company characterizes them as de minimus. However, a 50 per cent underestimation of 300 customers a month for five months, particularly in the first portion of the year when most of Minnegasco's sales are made, must represent a large portion of the total claim by Minnegasco in this adjustment.

Staff further contends that the estimate of customer conversion, another aspect of the new customer estimate, is ***38** also speculative. Staff notes that while the saturation of gas heat in the immediate area served by Minnegasco is very high, staff witness Black indicated that a survey by telephone he had conducted regarding number of customers who heat with fuel oil indicated the potential conversions might be substantially greater than that estimated by Minnegasco.

(B) Company Position:

Company contends that its adjustment for new customer additions in 1979 should be allowed. Company contends that it is absolutely proper to base this adjustment on the informed judgement of somebody having years of experience in the field. Company contends that company witness Schroedermeier has had responsibility for Cengas operating budgets since 1955 and is responsible for the adjustment ultimately included in this filing. Company witness Schroedermeier utilized historical data and experienced judgement to arrive at the projected increase in 1979 customers. Further, company witness Pooler testified that he and his staff had substantiated company witnessSchroedermeier's estimate using linear regression equations, one of which proves statistically significant. That particular equation verified company witness Schroedermeier's customer estimate in Minnegasco's view.

Company contends that staff witness Black's criticism that Minnegasco ignored conversions is invalid. Company points out that company witness Schroedermeier testified that about 25 conversions were included in the estimate of new customer additions for 1979.

Minnegasco further argues that this is a known and measurable change and should be accordingly allowed. Company contends that it is known with reasonable certainty and measurable with reasonable accuracy that a minimum of 880 new customers will be added in 1979. Accordingly, company concludes that the adjustment should be allowed by the commission and that its denial would be unfair and improper.

Commission Findings

The commission finds that staff's position regarding Minnegasco's proposed adjustment for customer growth should be adopted for the reasons set forth in (A) above. The commission finds that Minnegasco's primary basis for deriving its customer growth adjustment is to estimate new housing starts by talking to bankers, construction officers, and others. The commission finds that Minnegasco did not participate in any survey and did not derive any information about South Dakota and its situation through such contacts. The commission finds that, in any event, such contacts were a poor, if not irrelevant basis, to determine customer growth. Further, the commission finds that company's witness responsible for the customer growth adjustment not only did not have any studies or contacts with individuals in South Dakota in the banking and other housing-related industries, but took the South Dakota manager's estimated report of customer growth determined in August of 1978 and made numerous unsupported reductions thereto. The commission finds that not only did the company's witness lower in the case of residential customers or ignore in the case of industrial customers the estimates provided by its regional manager, but those estimates provided by the regional manager are speculative in any event. Hence, the commission finds that this is a situation where company's witness who had no information or basis for determining customer growth in South Dakota reduced or ignored customer growth as determined by South Dakota's manager whose determination, while speculative and not subject to verification, at least had some idea of the circumstances existent in South Dakota. The commission finds Minnegasco's linear regression analyses to be based upon inadequate data and undeveloped methodology. As a result, the commission finds no reliance can be placed thereon.

The commission further finds that in other proceedings dealing with other subject matters, Minnegasco has advised the commission of higher customer growth than Minnegasco has provided for in this proceeding.

The commission further finds that uncertainty and doubt is raised by Minnegasco's estimate of customer growth relating to Exh S–3 which shows predicted customer growth compared to the increases actually experienced. The commission finds that there were underestimates of customer growth in several months for which actual increases were known.

Finally, the commission finds that the estimate of customer conservation, another aspect of the new customer estimate, is speculative and unsupported. Additionally, the commission finds that little or no consideration or recognition of possible conversions were utilized in estimating customer growth. The commission finds that there are a number of present Minnegasco customers in South Dakota that could switch to natural gas for heating in face of the rising fuel oil prices this winter. Minnegasco failed to consider such factors in attempting to estimate the switch to natural gas for heating by its present customers. The commission finds that this failure is unfortunate in that Minnegasco's own reports indicate it is only losing customers in the residential and commercial classes without heating.

XIX.

Rate of Return

(A) Staff Position:

Staff recommends a return on common equity of 12.3 per cent and an overall rate of return of 10.16 per cent for Minnegasco based upon testimony of Dr. Gordon Taylor and upon the record in this proceeding. Staff witness Dr. Taylor adjusted the capital structure of Minnegasco to reflect staff's actual test-year approach. However, Dr. Taylor recognized and permitted Minnegasco's reduction of its long-term debt component by one-half of the amount of the 1979 sinking-fund requirements.

Staff witness Taylor provided a discounted-cash-flow analysis which utilized data relating to companies having similar risk characteristics to Minnegasco. Staff witness Taylor testified that the rate of growth in dividends actually paid by Minnegasco is the best measure to use in estimating the expected growth in dividends Minnegasco will pay in the future. He testified that investors would primarily form their expectations of the future rate of growth in Minnegasco's dividend payments on the growth in dividends that have actually ***40** been paid by Minnegasco. Staff witness Taylor did not find that earnings would be a reliable factor to be used in his DCF model since Minnegasco's earnings vary so much from year to year due, in part, to weather conditions. Consequently, staff witness Taylor examined Minnegasco's dividends over the past nine-year period and found that Minnegasco's policy is to maintain a steady, constant historical growth in dividends. He pointed out that Minnegasco has accomplished this by varying its pay out ratio.

Staff witness Taylor utilized both the continuous model and the annual model. The continuous model uses the dividend currently being paid for estimating the dividend yield. The annual model uses the dividend yield expected in the twelve months after the stock was purchased. Dr. Taylor testified that the continuous rate is always lower due to the fact that the continuous rate does not have the advantage of interest being paid on interest throughout the year which exists with respect to continuous compounding. Further, since dividends are paid quarterly, the continuous model tends to underestimate the required rate of return and the annual model tends to overstate the required return. Staff witness Taylor found that while the two models produce a range of reasonable values, quarterly compounding is closer in value to continuous compounding. Dr. Taylor utilized the most recent 12-month period for which stock price data was available and found that the average dividend yield for the continuous model was 8.73 per cnet. Dr. Taylor utilized the current dividend yield plus one-half of the estimated growth in dividends during the next twelve months for the dividend yield figure in his annual model.

In estimating the growth factor, Dr. Taylor used a five-year time frame to estimate investors' expected rate of growth in dividends. Dr. Taylor testified that the five-year period is proper in that investors primarily focus on the post-OPEC embargo performance of energy-related firms and that the five-year period he utilized is the period in which major changes occurred in the business environment for energy-related industries. Dr. Taylor noted that since 1974, Minnegasco's annual dividend payment has increased by six cents per year. He found that the best statistical estimate of the expected dividend growth for Minnegasco based on the five-year period from 1974 to 1978 is that Minnegasco would increase the dividend by another six cents each year. In utilizing the average of the next two years' growth rates in the annual model, Dr. Taylor concluded that the rate of return for Minnegasco would be 12.13 per cent. Dr. Taylor proceeded to use an exponential curve fit assuming a continuous compound growth rate in dividends in estimating the expected rate of growth in dividends for Minnegasco. This statistical method resulted in a 3.56 per cent dividend growth rate.

Dr. Taylor determined that the estimates of dividend yields and dividend growth for both the continuous and the annual models results in a range of 12.29 per cent for the continuous model to 12.51 per cent for the annual model. Dr. Taylor testified that 12.3 per cent was the most appropriate return on equity for Minnegasco in that quarterly compounding is more realistic and it would be closer to the continuous model estimate. Further, Dr. Taylor testified that 12.3 per cent would satisfy all legal requirements.

***41** Dr. Taylor also utilized two other factors in his analysis: the opportunity cost to investors of investing in Minnegasco compared to Minnegasco's required rate of return, and a possible flotation cost adjustment. Dr. Taylor testified that it was necessary to consider the expected opportunity cost to investors in forfeited returns from comparable risk firms before arriving at a final recommendation. Dr. Taylor selected a group of gas distribution companies that had relatively similar risks to Minnegasco. The group of firms were selected on the basis of seven specific criteria which established comparability to Minnegasco. Dr. Taylor developed a median rate of return required by investors as an indication of their opportunity cost with respect to the companies selected. For the continuous model, the median is median return is 12.32 per cent. For the continuous model, the required rates of return range from 10.49 per cent to 14.97 per cent. For the annual model, the range is from 10.59 per cent to 15.55 per cent.

Dr. Taylor found that the 12.3 per cent derived for Minnegasco fell in the middle of these ranges and confirmed the reasonableness of his DCF analysis.

As for the flotation cost, Dr. Taylor found that no additional return was required since there has been no indication that Minnegasco expects to issue additional common stock in the near term. Dr. Taylor testified that an allowance for fictitious flotation costs is not warranted and that Minnegasco's adjustment should, accordingly, be rejected.

Staff contends that company witness Dr. Johnson's criticisms of staff witness Taylor's analyses are without merit. Staff points out that the crucial aspect of a proper analysis of Minnegasco's growth factor is expected growth in dividends since there is no other factor which investors can rely on with any degree of predictability with regard to Minnegasco. Staff points out that Dr. Taylor set forth the wide swings in Minnegasco's earnings and its pay out ratios in order to point out the difficulty any investor faces in determining a trend from this information. As a result of the wide variations in both earnings and pay out ratios, staff points out that Dr. Taylor was fully justified in his conclusion that investors base their expectations of growth in dividends primarily on Minnegasco's dividend payment policies. Staff notes that Dr. Johnson acknowledged that Minnegasco's earnings were not stable. Minnegasco attempts to maintain more stability in dividends than in earnings by changing its pay out ratio from year to year. Staff contends that this stabilizing policy of Minnegasco is exactly what confirms the propriety of Dr. Taylor's determination that the growth in dividends is the factor on which investors focus.

Staff further contends that Dr. Johnson's criticisms of Dr. Taylor regarding Dr. Taylor's calculation of the dividend yield is without any foundation or substance. Dr. Taylor pointed out that the proper dividend payment figure to use for calculating the dividend yield in the continuous DCF model is the indicated dividend which is the latest quarterly dividend paid or announced multiplied by four since the DCF model utilizes an estimate of the total yield expected by investors over the coming twelve months plus the expected yield from growth in dividends. Staff notes that either the expected indicated dividend must be used in the continuous ***42** DCF model or the expected indicated dividend with the addition of one-half of the annual expected growth in dividends must be used in the annual DCF model. Staff points out that Dr. Johnson has acknowledged that, in the application of the DCF formula, yield is properly calculated by dividing the dividend to be paid in the next year.

Staff contends that Dr. Johnson utilizes a single spot dividend figure at one point during the year. However, Dr. Yaylor testified that the dividend yield figure for Minnegasco changes significantly when a spot dividend figure is employed, particularly when the calculations are first made the day before and the day after Minnegasco's announcement of its annual dividend. Consequently, Dr. Taylor recommends utilization of an average of monthly yields.

Additionally, staff points out that Dr. Johnson purports to have updated certain of Dr. Taylor's data with resultant increases in the cost of capital. Staff contends that Dr. Johnson's changes consist of a substitution of certain of Dr. Johnson's elements with other elements in staff witness Taylor's DCF formula that relate to a different time period. Dr. Taylor testified that the dividend yield and dividend growth estimates must be compatible and that Dr. Johnson is in error in attempting to utilize one aspect of the formula and replace it with another from a different time span. Dr. Taylor further testified that the dividend yield and the dividend growth are inextricably tied together and any attempt to substitute unrelated factors is improper. Consequently, staff contends that any results derived therefrom are without merit.

Dr. Johnson testified that Dr. Taylor's method assumes a continued low pay out ratio. Staff points out, however, that Dr. Taylor's analysis of the pay out ratio is based upon the assumption that Minnegasco will vary it in the future as it has in the past. As previously noted, Minnegasco varies the pay out ratio in order to maintain steadily growing dividend payments.

As for Dr. Johnson's general criticism of Dr. Taylor's growth estimates, staff contends that that criticism is shown to be without merit in the context of the market's reaction to the announcement of an increase of ten cents per share in Minnegasco's annual dividends in July of 1979. Staff points out that if Dr. Johnson's growth estimate were correct, the ten-cent per share increase should have resulted in no change in the market price of Minnegasco's stock. However, Dr. Johnson has acknowledged that the price of Minnegasco's stock increased. The increase commenced immediately with the dividend announcement although, as Dr. Taylor testified, the stock market, including utility stocks, was declining. Staff contends that the increase in the market price can be explained in terms of the growth estimate anticipated by investors and that investors had a perception of a lower growth rate in dividends than Dr. Johnson's estimate which caused the price of the stock to be bid up by investors when the perception was changed by the announcement of the higher dividend. Dr. Taylor found that the increase in Minnegasco's stock price is objective evidence that a lower growth rate closer to his estimate was expected by investors.

Staff contends that Dr. Johnson's recommendations are flawed and should not be relied upon. Staff points out that ***43** Dr. Johnson averages together the results of four different estimates of dividend growth rather than relying on Minnegasco's previous dividend performance. Dr. Johnson utilized implied growth, Value Line estimated growth, earnings growth, and dividend growth. Staff points our that rather than utilizing actual 1978 earnings, Dr. Johnson utilized Value Line's estimate even though the actual data was available. Dr. Johnson provided no explanation regarding why investors whould use an estimate of 1978 earnings when the actual figures were available. Staff further contends that Dr. Johnson utilized data which was inflated by 25 per cent in measuring historical dividend growth. Additionally, staff contends that Dr. Johnson's sample companies are not comparable to Minnegasco and that there has been no showing of comparability. Staff notes that Dr. Johnson utilized company witness Fleer's selection without any independent substantiation of comparability.

Staff also contends that Dr. Johnson's risk premium analysis is not a proper basis for determining a fair rate of return. Staff contends that the methodology is not sufficiently developed to be reliable. Staff points out that utilities like Minnegasco are not as risky as investments in nonregulated firms and that no accurate risk measure has been derived.

Finally, staff contends that Dr. Johnson's mixing of multiple approaches in deriving his recommendation is erroneous. Dr. Taylor testified that use of multiple approaches in deriving the growth factors is improper in that the only data base stable enough for investors to utilize in making estimates regarding Minnegasco is dividends. Staff contends that Dr. Johnson's use of four completely different estimating approaches and the averaging thereof is unreliable and provides an improper basis for evaluating Minnegasco.

Staff further points out that changes have occurred in the natural gas industry since 1978 which serve to enhance the prospects for companies engaged in natural gas distribution. Dr. Johnson himself stated that, while he was not too familiar with the Natural Gas Policy Act, he understood that the act would serve to increase the availability of gas supplies. Staff contends that such developments in the industry vividly establish the fact that the industry is in a stable and increasingly favorable condition.

Finally, staff contends that company witness Fleer's assertion that gas distributors should earn from 1.50 per cent to 2 per cent higher returns than electric utilities is erroneous. Staff points out that witness Fleer's study utilized companies not comparable to Minnegasco. Further, witness Fleer's sample contains firms whose percentage of total revenues attributable to gas distribution operations is far less than the 100 per cent received by Minnegasco. Consequently, witness Fleer's sample is necessrily weighted toward the higher equity values. Staff also points out that Mr. Fleer's study utilizes a time period when the gas supply situation was very uncertain and unstable. Finally, staff contends that Dr. Taylor fully and explicitly considered the investors' needs in this regard and his recommendation should be adopted by the commission.

(B) Company Position:

Minnegasco presented two witnesses in support of its requested 11.21 per cent ***44** overall rate of return to be applied to rate base. Company witness John W. Fleer, Minnegasco's chief financial officer, calculated all facets of the cost of capital using a 14.5 per cent cost of common equity which was at the lower end of the range recommended by company witness Robert L. Johnson. Company witness Fleer analyzed the return on common equity required for market price to equal book value for 24 Moody's electric utilities and for the 20 largest gas distributors. Company witness Fleer concluded that gas distributors must earn from 1.50 per cent to 2 per cent greater rate of return on common equity than electric utilities to sell at book value under the present market conditions.

Company witness Dr. Johnson utilized three methods to determine the cost of equity for Minnegasco; i.e., risk premium, discounted cash flow, and comparable earnings. On the basis of the risks premium method, Dr. Johnson testified that the minimum market cost of equity at this time was at least 14.4 per cent to 14.8 per cent.

In Dr. Johnson's discounted-cash-flow analysis, he estimated the growth factor utilizing several techniques to avoid the risk of serious error. Dr. Johnson studied implied growth rates, Value Line growth forecasts, and four historical growth rates in arriving at his growth determination. Combining the six growth estimates, Dr. Johnson arrived at a market cost of equity for Minnegasco of 14 per cent to 15 per cent. Dr. Johnson also performed a regression analysis which served to confirm this range of market costs.

Finally, Dr. Johnson found that, based on his comparable earnings analysis, the market cost of equity within Minnegasco's risk range would be between 14 per cent and 14.9 per cent.

Further, Dr. Johnson found that the market cost of equity for Minnegasco of 14 per cent to 15 per cent should be adjusted upwards to 14.8 per cent to 15.9 per cent to avoid dilution of stockholders' equity and earnings per share. Dr. Johnson's adjustment was made to allow for flotation costs, market pressure, and general market decline.

Minnegasco contends that staff witness Dr. Taylor's analysis is erroneous and that Dr. Taylor's recommended 12.3 per cent must be adjusted upwards to 12.78 per cent to meet his revised investors' expected opportunity cost analysis. Further, Minnegasco contends that Dr. Taylor's recommended 12.3 per cent must be adjusted upward to a minimum of 14 per cent to permit Minnegasco to sell at a market price equal to book value.

Minnegasco notes that Dr. Taylor utilized his investors' expected opportunity cost as a check on the reasonableness of the results of his DCF analysis. Minnegasco further notes that the median rate of return required by investors calculated from Dr. Taylor's 12 comparison companies was 12.13 per cent for the continuous DCF model and 12.32 per cent for the annual DCF model. As a result, Dr. Taylor ranked the data for his 12 selected companies and concluded that his recommended 12.3 per cent was reasonable in that it was in the middle of the two ranges of the opportunity costs to investors. Minnegasco contends that as a result of Dr. Taylor's revision of the dividend data for Piedmont Natural Gas Company, the median for his 12 companies must be raised to 12.64 per cent for the continuous DCF model and 12.88 per cent for the annual DCF model. Consequently, Minnegasco contends that the 12.3 per cent is now below the medians originally determined and should be adjusted upward. Minnegasco further contends that Dr. Taylor ignored the change in medians by revising his methodology from a 12-company comparison group to a 13-company group by including Minnegasco. Minnegasco claims that this is inappropriate and should be rejected.

Minnegasco also contends that staff witness Taylor's recommended 12.3 per cent is inappropriate because it will not allow market price to equal book value. Minnegasco points out that it has earned over 14.5 per cent on average book equity each year since 1975 and that its stock price is approximately equal to its book value. Further, Minnegasco states that its witness Fleer's analysis establishes that for the 20 largest gas distributors, earnings on equity of over 14 per cent are required to support a market price equal to book value and that of the 11 companies with earnings on common equity less than 14 per cent in the 20 largest gas distributors study, all such companies were selling at market prices less than book value. Finally, Minnegasco notes that of the natural gas companies examined by Dr. Johnson, with one exception, those companies were selling below book value where earnings of less than 14 per cent existed. Minnegasco contends that Dr. Taylor's position is untenable and does not recognize that investors require a higher rate of return on equity for gas distributors than for electric companies or for combination gas and electric firms. Minnegasco notes that it is strictly a gas distributor and that the rate of return allowed to it must be greater than that recommended by Dr. Taylor. Minnegasco further points out that company witness Fleer's study establishes that Minnegasco should be allowed between 1.5 per cet to 2 per cent higher return than electric utilities.

Minnegasco also criticizes Dr. Taylor's determination of the growth factor utilized in Dr. Taylor's DCF model. Minnegasco contends that Dr. Taylor's growth determination has no foundation or support in that Dr. Taylor's contention that investors' expected growth is based entirely upon historical growth in dividends over the 1974 to 1978 period. Company notes that Dr. Johnson's analysis establishes that investor expectations for growth are not formed entirely, or even primarily, by a determination of historical growth rates over any given period and that it is unusual to rely exclusively on historical growth over one period of time without making further analyses. Minnegasco criticizes Dr. Taylor's reliance on historical growth because pay out ratios of Minnegasco and of the gas industry in general declined during the period utilized by Dr. Taylor. As a result, Dr. Taylor's analysis is, in Minnegasco's view, understated as far as the expected future growth in Minnegasco's dividends. Further, Minnegasco claims that Dr. Taylor's gorwth determination is understated because of Minnegasco's ten-cent dividend increase made in July of 1979. Minnegasco contends that Dr. Johnson's analysis, which relies on several different methods in deriving growth estimates, is the proper analysis and should be adopted by the commission.

Finally, Minnegasco contends that its two proposed adjustments to capital structure—i.e., reducing long-term debt by one-half of its 1979 sinking-fund requirements and increasing average common stock equity by $2,172,500 to reflect ***46** the average increase from retained earnings projected for 1979—should be allowed. Staff witness Dr. Taylor concurred that the reduction in long-term debt proposed was appropriate and should be allowed. However, Dr. Taylor testified that the retained earnings adjustment was not known and measurable and should not be allowed. Minnegasco claims that on the basis of its 1974 to 1978 historical trend, its adjustment for retained earnings for 1979 should be allowed. Minnegasco contends that staff witness Taylor is not recognizing a very conservative known and measurable change and, as a result, has improperly recommended disallowance of the proposed adjustment.

Commission Findings

The commission finds that on the basis of the expert testimony and the evidentiary record herein, Minnegasco's return on common equity should be set at 12.3 per cent. The commission finds that staff witness Taylor properly utilized the discounted-cash-flow method. The commission finds that the rate of growth in dividends actually paid by Minnegasco is the best measure on the basis of the record herein to use in estimating the expected growth in the dividends Minnegasco will pay. The commission finds that an analysis of past earnings and dividends is usually proper in estimating dividend growth but, as Dr. Taylor notes, earnings experience is not reliable for Minnegasco. The commission consequently finds that on the basis of the record herein, earnings are not a reliable factor to be utilized in the DCF model for Minnegasco in that Minnegasco's earnings vary so much from year to year, in part, due to weather conditions. The commission further finds that Minnegasco's dividends over the past nine-year period are the result of Minnegasco's policy to maintain a steady, constant historical growth in dividends and that Minnegasco has accomplished this stability through utilizing varying pay out ratios. The commission finds that Dr. Taylor's use of the historical growth in dividends, and the time frame selected for measurement thereof, are proper in that they are representative of investor expectations.

The commission finds that on the basis of the record herein, Dr. Taylor's use of both the continuous model and the annual model utilizing the dividend currently being paid as the basis for estimating dividend yield and the dividend yield expected in the twelve months after the stock was purchased, respectively, is proper and provides a sound basis for evaluating a fair and reasonable rate of return. The commission finds that the continuous model tends to underestimate the required rate of return while the annual model tends to overestimate the required return due to the quarterly payment of dividends. The commission finds that while the two models produce a reasonable range of values, quarterly compounding is closer in value to continuous compounding. The commission further finds that Dr. Taylor's utilization of the most recent 12-month period for which data was available is proper and that, on that basis, the average dividend yield for Minnegasco was 8.73 per cent.

The commission finds that the five-year time frame utilized by Dr. Taylor is appropriate in determining the growth factor for Minnegasco. The commission finds that this time frame serves to best estimate investors' expected rate of ***47** growth in dividends in that investors primarily focus on the post-OPEC embargo performance of energy-related firms. The commission further finds that this five-year time frame reflects the major changes occurring in the business environment for energy-related industries.

The commission finds that the estimates of dividend yields in the growth for both the continuous and annual models results in a range of 12.29 per cent for the continuous model to 12.51 per cent for the annual model and that the methodology utilized by Dr. Taylor in deriving his range is the only sound and supported methodology in this record. Dr. Taylor's recommendation that Minnegasco receive a return on common equity of 12.3 per cent is well within the range of reasonableness and is proper. The commission finds that a 12.3 per cent return will enable Minnegasco to attract necessary capital, remain financially healthy, and assure confidence in Minnegasco's financial integrity.

The commission finds that Dr. Taylor's opportunity cost to investors' analysis confirms the reasonableness of the 12.3 per cent return recommendation. The commission finds that Dr. Taylor's opportunity cost analysis, based upon a sample derived from seven specific and objective criteria for establishing comparability, is sound. The commission finds that Minnegasco's contention that Dr. Taylor's correction for a Value Line error in and of itself requires a revision to Dr. Taylor's conclusions is without merit. The commission finds that Minnegasco was properly included in the sample utilized by Dr. Taylor for evaluating the opportunity cost to investors of investing in Minnegasco. Further, the commission finds that Dr. Taylor properly determined the ranges of estimates of required rates of return from the lowest firm to the highest. The commission finds that the 12.3 per cent recommended return is in the middle of the two ranges developed in Dr. Taylor's analysis. The commission finds Minnegasco's emphasis on medians to be misplaced in that Dr. Taylor's opportunity cost analysis determined the ranges of reasonableness. His 12.3 per cent recommendation is whthin the range and his analysis fully confirms the reasonableness of his DCF results.

The commission further finds that Dr. Taylor's rejection of Minnegasco's flotation costs adjustment is fully supported and is proper. The commission finds that Minnegasco's proposed flotation costs adjustment is speculative and, in light of the record evidence regarding Minnegasco's intention to issue no new equity within the near future, should not be allowed.

The commission finds that Minnegasco witness Johnson's recommendation utilizing results of four different estimates of dividend growth rather than relying upon Minnegasco's previous dividend performance is inappropriate in this proceeding due to Minnegasco's corporate policies. The commission finds that Dr. Johnson's failure to utilize actual data, his uncritical reliance upon Value Line reports, his inaccurate and inflated measurement of historical dividend growth, and his uncritical reliance on, and incorporation of, Minnegasco's witness Fleer's comparable company selection without independent substantiation or justification causes the commission to find Dr. Johnson's recommendations to be unreliable.

The commission also finds that risk premium analyses are unreliable in that ***48** no accurate measurement has been developed for evaluating the risk premium. As a result, the commission finds that such analyses are not of assistance in setting a fair return.

The commission finds that changes that have occurred in the natural gas industry since 1978 have enhanced the prospects for firms engaged in natural gas distribution. Further, the commission finds that the Natural Gas Policy Act will serve to provide greater stability in, and greater availability of, gas supplies thereby reducing risks accordingly. The commission also finds that by providing Minnegasco with a purchased gas adjustment clause which allows automatic pass through of all increases or decreases in the costs of purchased gas to consumers, Minnegasco's business risks are substantially minimized.

Additionally, the commission finds that, in light of Minnegasco's substantially higher equity ratio and the consequent protection provided to equity holders as a result thereof, the 12.3 per cent return allowed herein is more than adequate for Minnegasco to attract necessary capital, to remain financially healthy, and to assure confidence in Minnegasco's financial integrity.

Finally, the commission finds that no witness performed a valid comparable earnings study. The commission finds this to be unfortunate in that such a study normally provides assistance in setting a fair rate of return. Nonetheless, the commission is fully satisfied that a 12.3 per cent return on equity is just and reasonable on the basis of this evidentiary record.

Further, the commission finds that such a return is well within the range of reasonableness as determined by the commission in past proceedings.

XX.

Rate Design

Two rate design issues which were raised and litigated in this proceeding have for differing reasons been resolved. Due to the inability of efficiently and economically implementing a system-wide late payment charge at this time, the commission will consider proposals for such a charge in future Minnegasco rate proceedings. Additionally, no party seriously disputes the propriety of consolidating the five firm rate schedules into one general firm rate schedule. The commission finds that this is proper and that as a result of said consolidation, Vermillion and Meckling customers should not be subject to any late payment charge prospectively. However, the commission finds that any costs associated with providing consistency to these customers by changing the billing in Minneapolis should not be permitted as an expense above the line in light of Minnegasco's responsibility for creating this situation.

Further, the commission finds that Minnegasco shall conduct and complete all studies required in PUC Docket F–3080 within six months from the date of the commission's decision and order entered herein. The commission finds that there has been no reasonable explanation or excuse presented regarding why Minnegasco has refused or failed to file such studies as were required and that the commission shall not condone any further unreasonable delay in the commencement and completion of said studies.

Disputed Issues

(A) Staff Position:

Staff witness Petersen recommended ***49** consolidation of the firm rates. Staff witness Petersen testified that the commission had been concerned at the time of Minnegasco's acquisition of Cengas in 1976 not to disturb the existing rate structure and that it was his opinion that, presently, sufficient time had passed that the movement to a uniform rate structure was appropriate and in order. While staff feels that Minnegasco has provided minimal support for its consolidation of the various rate schedules, staff contends that the potential long-term benefits of consolidating those schedules outweigh the temporary benefits that certain individual communities presently enjoy.

As to allocation of costs between customer classes, staff witness Black testified that staff had not arrived at a definite recommendation. Staff feels that neither Minnegasco nor John Morrell provided a thorough analysis of how various costs relate to customer classes although both Minnegasco and John Morrell provided general descriptions of why they allocated costs as each did. Staff points out that public policy is always a factor in determining the kind of allocation since allocations are inevitably arbitrary to some degree. Due to the lack of detail regarding what costs are related to which customer classes, staff considers policy to be a particularly important consideration in this proceeding.

Staff feels that it is inappropriate to refuse to consider Minnegasco's position on cost allocation on the theory that there has been a failure to sustain a burden of proof. Staff notes that the alternative proposal by John Morrell has not been shown with any more specificity or substantiation. Staff notes that John Morrell witness Brubaker weighted the customer costs for interruptible customers at ten times the cost of firm customers. Consequently, witness Brubaker assigned 8 per cent of customer costs to interruptible customers and 92 per cent to firm customers. Staff feels that the derivation of John Morrell witness Brubaker's weighting has not been demonstrated and that the formula is unexplained and arbitrary.

Staff points out that regulatory precedent exists for Minnegasco's position such as the allocation formulas utilized by the Federal Energy Regulatory Commission to allocate costs between firm and interruptible customers. Staff notes that FERC for a long period of time utilized a 50 per cent allocation of capacity costs to demand and 50 per cent to volumetric costs. More recently, FERC has adopted a somewhat different formula which allocates 75 per cent of the capacity costs to volumetric costs and only 25 per cent to the demand costs. Staff notes that John Morrell's recommendation would, accordingly, be even more contrary to recent FERC practice in this area.

Further, staff notes that John Morrell and other interruptible customers gained an economic advantage from using natural gas. Staff notes that one of the complaints raised by certain industrial customers is that they would like to be interrupted far less than is presently occurring. Staff concludes by contending that fairness, as well as recognition of the economic benefits to the interruptible customers, leads to adoption of Minnegasco's allocation in this proceeding.

(B) Company Position:

Company contends that its proposed rate design should be adopted in its entirety. Minnegasco witness Schroedermeier sponsored the proposed rate schedules and a comparison of impacts on average firm and interruptible customers. Company witness Schroedermeier testified that the four primary rate design objectives were to recover the revenue requirements of Minnegasco's South Dakota jurisdictional operations; to consolidate, simplify, and standardize both the firm and interruptible rates; to promote energy conservation by reducing the number of blocks and moving toward a more volumetric rate; and to recognize the cost incidence between firm and interruptible service. As to the latter standard, company witness Schroedermeier testified that the rates must reflect the cost of providing service to these two classes of customers. If one customer class is billed on rates that exceed the cost of serving it, the other classification benefits by paying a lesser rate. Therefore, company witness Schroedermeier testified that it is important that each class pay its own way.

Minnegasco included in its filing a cost-of-service study. The study established in Minnegasco's view the allocation of cost to be 81 per cent to firm customers and 19 per cent to interruptible customers. Company notes that it is this cost-of-service allocation which is the main dispute between company and John Morrell.

Minnegasco points out that both John Morrell and Minnegasco agree that a cost-of-service study cannot be absolutely precise. Minnegasco notes that such a study involves a high degree of judgement and is capable of many different methods to compute cost to customer classes. Minnegasco further points out that its method is identical to that used in its Minnesota rate increase proceeding.

The study performed by John Morrell and the study performed by Minnegasco differ in three respects. Minnegasco's division of demand costs between demand and commodity components recognizes the benefit interruptible customers receive from Minnegasco's purchase of contract demand. Minnegasco contends that by classifying all demand costs to only the demand component, this benefit is ignored as was done in Minnegasco's view by John Morrell's study. Minnegasco's division of customer costs between both the customer classification and the commodity classification recognizes that the investment in costs that follow large customers are much greater than for residential and small volume customers. Minnegasco notes that John Morrell's study does make an attempt at allocating 8 per cent of these costs to interruptible customers by utilizing a ten-to-one weighting of interruptible customers which is based strictly upon judgement.

Further, the allocation of distribution costs by Minnegasco is based upon the higher distribution costs associated with larger volume customers and that 50 per cent of those costs should be assigned to the commodity component. John Morrel allocated distribution costs on a 50–50 basis to the demand and customer classifications while Minnegasco utilizes the 50–50 allocation to the demand and commodity classification. Minnegasco contends that distribution costs are largely related to its investment in distribution mains and that the size of gas lines vary in different areas based on the size of customers located in those areas. Consequently, Minnegasco contends that distribution costs are more closely ***51** associated with the size of the required to deliver large volumes of gas and not to the number of customers. For this reason, Minnegasco chose to assign 50 per cent of distribution costs to the commodity classification.

Minnegasco contends that its study is based on a cost-of-service formula which fits its particular operation. Further, Minnegasco contends that no entity should receive a free ride in this regard.

Minnegasco contends that John Morrell is being treated fairly under the proposed rate designs of Minnegasco. Minnegasco points out that John Morrell is the customer in South Dakota which benefits most from the ten-cent seasonal rate decrease for usage over 1,000 Mcf per month. Minnegasco notes that the reduction is designed to lessen the impact of a volumetric rate design on those large volume interruptible customers who are heavily curtailed during the winter months. Minnegasco disputes John Morrell's recommendation that a larger sum reduction is in order because such a reduction would increase the rate to all other interruptible customers on the system, most of which represent space-heating loads.

Minnegasco concludes that its proposed firm and interruptible rate designs represent a fair and equitable treatment of all customers on the system and that they meet the needs of the system. Further, Minnegasco takes the position that the various goals of proper design of rates are accomplished by its proposals. Minnegasco views John Morrell's claims to be contrary to those goals and strictly based upon self-interest considerations.

Minnegasco further points out that customer understanding, simplicity, and ease of administration and other benefits will accrue from its rate structure proposal.

(C) John Morrell Position:

John Morrell contends that the existing rate structure has been effective and that no combination of interrutible rates should be made in this proceeding. John Morrell contends that the rate structure existent during the past three years has served well in accomplishing both revenue stability and rate stability. Additionally, John Morrell contends that the existing rate structure and interclass relationships accomplish three primary goals of sound rate design; i.e., revenue stability, rate stability, and efficiency of use. John Morrell notes that a review of Minnegasco's annual reports demonstrates a healthy financial picture with constant growth in both earnings and dividends over the past years. John Morrell points out that, at least in part, the cost-tracking ability of Minnegasco's existing rate schedules is responsible for such a good performance record.

John Morrell further argues that while simplification is a legitimate interest of Minnegasco, such simplification should only occur after adequate information and data in the nature of load studies, billing determinants, a definitive cost-of-service study by class, and other analytical studies are performed. John Morrell points out that both staff witness Petersen and John Morrell witness Brubaker have testified that without such analyses being performed, any rate design will be subject to question. John Morrell contends that Minnegasco's existent rate structure should not be changed without a deliberate approach and without sound data. Further, John Morrell contends that the consolidation ***52** of the existing interruptible schedules collects the quality of service factor in that John Morrell's interruptible status is the first type of customer to be interrupted on Minnegasco's South Dakota system.

John Morrell also disputes Minnegasco's allocation to the interruptible class. John Morrell points out that the rate proceeding before the commission deals with matters other than purchased gas costs. John Morrell notes that a major portion of those nonpurchased gas costs are construction costs incurred for new residential service. Consequently, John Morrell maintains that Minnegasco's proposal to allocate the requested increase in revenues so as to increase the nonfuel base rates of interruptibles by 80 per cent and the nonfuel base rates of firm customers, a substantial portion of which are residential customers, by only 26.7 per cent is completely contrary to experienced cost incurrence. John Morrell points out that company's own witnesses admitted that the increased revenue requirement in this proceeding has nothing to do with fuel cost increases which are covered by the purchased gas adjustment clause. John Morrell contends that its witness Brubaker's approach in allocating the increase on the same basis—i.e., revenues less purchased gas costs—is proper and that Minnegasco's rebuttal testimony merely avoided this reality. John Morrell points out that both Minnegasco and John Morrell made allocations to firm rates and interruptible rates only and neither made an allocation to John Morrell and Company.

Further, John Morrell contends that Minnegasco's emphasis on the need to consider the cost of alternate fuel in setting rates for interruptibles is without merit. John Morrell contends that the differences to Morrell between natural gas cost and the cost of oil is relatively minimal. Hence, Minnegasco's reliance upon this factor is ill-placed.

John Morrell points out that in company's presentation on allocation, Minnegasco emphasized the benefits that interruptible customers receive as a result of the contract demand obligation incurred so as to assure firm service adequacy. John Morrell notes that its witness Brubaker explained that the interruptible customer is basically a means which would allow Minnegasco to buy a lower contract demand and still serve the needs of all of its firm customers because Minnegasco could take part of its interruptible customers' load off in the winter.

John Morrell further points out that commission staff recognizes that the record does not support consolidation of interruptible rate schedules or company's proposed cost allocation. John Morrell notes that staff relies heavily upon the benefits theory which assumes that the interruptible customers enjoy the benefits of the contract demand level provided by the firm customers. John Morrell contends that it has totally established that the benefits flow both ways and that the presence of interruptible use allows Minnegasco to buy a lower contract demand in times of plentiful gas supply and in rate design, some capacity costs are allocated to the interruptible use which spreads the fixed costs over a greater number of Mcf.

John Morrell further contends that staff acknowledges there is no record support for the allocation of the increase, but ignores John Morrell witness Brubaker's position that the allocation of increased revenues should be assigned as ***53** a uniform percentage increase on the present revenues less revenues associated with purchased gas costs. John Morrell notes that regardless of whether the commission adopts, in whole or in part, consolidation of either firm or interruptible rate schedules, the allocation of the increase should be made pursuant to John Morrell witness Brubaker's recommendation in that the nonpurchased gas costs are the only reason for Minnegasco's rate increase request in this proceeding.

John Morrell concludes that the commission should adopt a rate design which does not allow any consolidation of interruptible rate schedules and which satisfies the following formula: present revenues per class less gas costs times percentage increase on base revenues excluding fuel revenues plus gas costs equals new revenues. John Morrell contends that this formula is the only formula of record which is uncontroverted and which is fully supported in the record.

(D) ACORN Position:

ACORN contends that company's proposed rate design should be adopted. ACORN points out that Minnegasco's proposal would assign 67 per cent of the required rate increase to the firm customers and 33 per cent to the interruptible customers while John Morrell's recommendation would require the firm customers to meet 96 per cent of the required rate increase and assign only 4 per cent of the increase to the interruptible customers.

ACORN takes the position that gas proceedings must be distinguished between electric proceedings in that problems have existed in the supply of natural gas which require a shift from pure costing methodology to cost determinations which are based upon judgement and policy considerations which may not exist in electric rate proceedings. ACORN points out that as a result of shortages commencing in the 1950's, a system of priorities was developed by the Federal Energy Regulatory

Commission and its predecessor wherein residential and small volume commercial gas customers were provided a favored position and other customers were placed in a category wherein service could be interrupted during shortages. Further, ACORN, as does commission staff, relies upon FERC precedent regarding proper allocation formulas between the demand and commodity components in determining a fair rate design. ACORN further contends that the Natural Gas Policy Act of 1978 attempts to ease the burden on residential and small commercial consumers resulting from the increases in prices to be granted to producers by the act. ACORN points out that the Natural Gas Policy Act of 1978, to a certain extent, requires charges for new gas and monthly inflation adjustments to be incrementally priced to industrial end users. ACORN notes a recent FERC rule-making proceeding wherein FERC is proposing to strike a balance between the two goals of maximizing flow through of incremental costs to industrial facilities and minimizing fuel switching. ACORN concludes that it is clear that the Natural Gas Policy Act represents a policy decision by the United States Congress and, as such, should be considered by this commission in adopting a rate design in this proceeding.

As for John Morrell's presentation, ***54** ACORN points out that John Morrell witness Brubaker neither performed nor directly relied upon any study from another case in reaching his recommendation in this proceeding. Rather, ACORN contends that John Morrell witness Brubaker's proposal is supported solely by his personal judgement and philosophy and not upon any empirical or other objective analysis. ACORN summarizes John Morrell witness Brubaker's recommendation as consisting of assignment of all capacity costs to firm customers, assignment of all of the natural gas demand charge to the interruptible class, division of the commodity cost between the two classes on a volumetric basis, assignment of 92 per cent of the customer costs to the firm customers, assignment of 91.8 per cent of the distribution cost to the firm class, and a shift from the strictly costing stage to objectives of rate design stage wherein witness Brubaker recommends that the commission exclude the cost of gas out of Minnegasco's total revenues at present rates and apply a uniform percentage increase to the balance. ACORN finds that John Morrell witness Brubaker's presentation has no empirical or other basis for justifying or substantiating any of his recommendations.

ACORN further questions the judgement exercised in arriving at John Morrell's recommendation. ACORN points out that it is reasonable to conclude from a historical perspective that estimates of the needs of large commercial users of gas were taken into consideration when building pipelines and plant capacity. Further, ACORN points out that it is clear and unequivocal that the interruptible class of customers benefit and use the capacity provided through fixed costs. ACORN further points out that it is equally clear that the interruptible customers benefit from other fixed costs such as the Northern Natural demand charge paid by Minnegasco. Consequently, interruptible customers are deriving a benefit from the use of capacity and it is only equitable that they fairly contribute toward those capacity costs.

Additionally, ACORN notes that John Morrell witness Brubaker's recommendation is totally contrary to the historical development of Federal Energy Regulatory Commission allocations between demand and commodity and is contrary to the purposes and intent of the Natural Gas Policy Act of 1978.

Commission Findings

The commission finds that Minnegasco's rate design proposal should be adopted for the reasons set forth in (B) above and on the basis of commission staff and South Dakota ACORN's recommendations set forth in (A) and (D), respectively. The commission finds that Minnegasco's proposals regarding rate design will provide for recovery of Minnegasco's revenue requirements as determined by this commission; will consolidate, simplify, and standardize both the firm and interruptible rates; will promote energy conservation by reducing the number of blocks in moving toward a more volumetric rate; and will recognize the cost incidence between firm and interruptible service. The commission finds that Minnegasco's cost-of-service study establishes that the allocation of cost to firm customers should be 81 per cent and to interruptible customers 19 per cent. The commission finds that while no cost-of-service study is absolutely precise, Minnegasco's is ***55** sufficient in this instance to justify and substantiate its proposed rate design.

The commission finds that Minnegasco's division of demand costs between demand and commodity components recognizes the benefit interruptible customers receive from Minnegasco's purchase of contract demand. The commission finds that John Morrell's attempt to classify all demand costs to only the demand component ignores such benefit received by interruptible customers. The commission finds that Minnegasco's division of customer costs between both the customer classification and the commodity classification recognizes that investment in costs that follow large customers are much greater than for residential and small volume customers. The commission notes that John Morrell's study allocates 8 per cent of these costs to interruptible customers but utilizes an arbitrary ten-to-one weighting of interruptible customers without any reasonable basis.

The commission further finds that the allocation of distribution costs by Minnegasco is based upon the higher distribution costs associated with larger volume customers and that 50 per cent of those costs should be assigned to the commodity component. The commission finds that Minnegasco's utilization of the 50–50 allocation to the demand and commodity classification is appropriate and that John Morrell's allocation of distribution costs on a 50–50 basis to the demand and customer classification is not justified. The commission finds that distribution costs are largely related to its investment in distribution mains and that the size of gas lines vary in different areas based on the size of customers located in those areas. The commission finds that distribution costs are more closely associated with the size of the main required to deliver large volumes of gas and not to the number of customers.

The commission finds that John Morrell, all other interruptible customers, and all firm service customers are being treated fairly under Minnegasco's proposed rate designs. The commission finds that John Morrell is the customer in South Dakota which benefits most from the ten-cent seasonal rate decrease for usage over 1,000 Mcf per month. The commission finds that this reduction is designed to lessen the impact of a volumetric rate design on those large volume interruptible customers who are heavily curtailed during the winter months. The commission further finds that John Morrell's that a larger sum reduction is in order because such a reduction would increase the rate to all other interruptible customers in the system, most of which represent spaceheating loads, is erroneous and is not substantiated. The commission further finds that Minnegasco's proposed firm and interruptible rate schedule consolidations represent a fair and equitable treatment of all customers on the system and such rate designs meet the needs of the system. The commission finds that such consolidation serves to enhance customer understanding, provides for simplicity, and leads to ease of administration and consequent cost savings as well as satisfying Minnegasco's revenue requirement.

The commission finds that while the evidentiary record in this proceeding is not as fully developed and detailed as it could be, the record fully supports the commission's findings herein. The commission finds that public policy considerations of fairness, equity, and recognition of economic benefits to interruptible customers mitigate toward adoption of Minnegasco's proposals. The commission further finds that the allocations adopted herein are in accord with Federal Energy Regulatory Commission precedent as well as this commission's past precedent. The commission finds that while the Natural Gas Policy Act of 1978 does not expressly apply to this proceeding, the commission's determinations herein are in no manner inconsistent with the objectives of said federal legislation.

Finally, the commission finds that the criticism by certain parties of John Morrell's participation in this proceeding is hereby expressly rejected. This commission has always and will continue to provide the opportunity for participation by any customer or group of customers. This commission believes that such participation fully enhances the rate-making process and leads to more informed judgments. While the commission may not adopt a certain intervenor's position in part or in whole, nonetheless, that participation raises issues which would not otherwise be addressed by this commission and, perhaps, never considered. The commission recognizes that all parties to all proceedings, before the commission have certain self-interests to be protected and that that is certainly no valid criticism to any party's participation before this commission.

XXI.

General Considerations

After reviewing the entire record in this proceeding, the commission finds that in future proceedings, more candor will be forthcoming when mutually agreed upon errors made by any party are discovered. This commission has never encountered a situation, other than in the instant proceeding, such total reluctance and, in certain instances, refusal, by an applicant to remedy errors which the applicant concedes exist and which all parties concur exist. Commission staff and most other utilities have never acted in such a manner before this commission and this commission will not tolerate such conduct in future proceedings.

The commission further finds that, normally, when a utility files a projected or future test year, that utility does not attempt to rationalize that estimates, projections, predictions, and other hypothecations are not what they are. The commission finds that Minnegasco is entitled to file the type of application it so desires as long as it complies with the applicable statutory provisions and with the commission's rules in form, but the fully projected test year utilized by the company is exactly that, a fully projected test period. The commission finds that the data utilized by company is based on multiple projections and estimates of many departments, individuals, and/or consultants that make up Minnegasco. As previously noted, it is this commission's finding that these adjustments are speculative since no one can project with certainty the outcome of the many issues related to a fully projected test period and their net effect on Minnegasco's revenues. For rate-making purposes, the commission finds that these projections should not be the basis for establishing rates for Minnegasco.

This commission has always in the past and has in this case found that the test period for rate-making purposes should be a known test period. The commission finds that staff's analysis set ***57** forth in its reply brief is absolutely correct that whatever the many relationships that are present in the incurring of costs, rate base, and service, the analysis of twelve months' data that are known will reflect these relationship. This commission has also recognized in the past, and has in this proceeding recognized, changes which are known and measurable. Unfortunately, certain of Minnegasco's recommendations contain a fundamental misunderstanding of the fact that known and measurable changes are recognized only in the context of the relevant test period. This misunderstanding serves to completely destroy the relationship between costs, revenues, and rate base reflected by an actual 12-month period. Again, the commission concurs with staff's analysis set forth in its brief that of fundamental importance in this proceeding and in understanding what this commission has found is the meaning of the terms known and measurable. Known and measurable changes do not relate to adjustments that cannot, by any standard or criteria, be said to be known and measureable today or at the time of Minnegasco's filing. Known and measurable changes are exactly that. The antithesis of known and measurable changes are adjustments that are based on estimates, projections, or predictions which may be totally arbitrary or only partially arbitrary. Known and measurable changes, on the other hand, are exactly that: known and measurable. The commission finds that Minnegasco's utilization of the phrase 'known minimum' in fact means 'estimated, projected, or predicted minimum.'

Finally, the commission finds that Minnegasco's attempt to create a year-end rate base must fail. This commission has found in the past and has found in this proceeding that the matching of revenues, expenses, and rate base is crucial for any rational and representative test period as may properly be adjusted for known and measurable changes not otherwise accounted for. While semantics are in the realm of form over substance, this commission refuses to recognize a fundamental distortion of a fundamental rate-making principle.

The commission hereby rules that all proposed findings of fact, conclusions of law, and orders submitted by the parties are hereby rejected.

Upon the foregoing findings of fact, the commission hereby enters the following:

Conclusions of Law

I.

That the commission has jurisdiction over the subject matter and the parties to this proceeding.

II.

That the commission's decision entered herein establishes just and reasonable rates for Minnegasco and fully comports with all statutory and constitutional requirements.

III.

That the suspension of Minnegasco's proposed rate schedules and related tariff sheets filed with Minnegasco's application is hereby terminated, and that said rate schedules and related tariff sheets are hereby rejected in their entirety.

***58 IV.**

That all pending motions and objections not heretofore ruled upon are hereby expressly overruled.

End of Document

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	)))))	**SETTLEMENT STIPULATION** **EL14-026**

It is hereby stipulated and agreed by and among Black Hills Power, Inc. ("Applicant" or "Black Hills Power") and the South Dakota Public Utilities Commission Staff ("Staff") (jointly "Party" or "Parties"), that the following Settlement Stipulation ("Stipulation") may be adopted by the South Dakota Public Utilities Commission ("Commission") in the above-captioned matter. In support of its Application for Authority to Increase Its Electric Rates ("Application"), Applicant does hereby offer this Stipulation, the Application and all supporting materials filed March 31, 2014, and thereafter. The Parties offer no answering testimony or exhibits, conditioned upon the Commission accepting the following Stipulation without any material condition or modification.

I. INTRODUCTION

On March 31, 2014, Black Hills Power filed with the Commission the aforementioned Application through which it requested authority to increase annual revenues by approximately $14.6 million.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (collectively "BHII") filed a Petition to Intervene. On the same date, Dakota Rural Action ("DRA") also filed a Petition to Intervene. The Commission issued its Order Granting Intervention to BHII and DRA on June 26, 2014.

On September 4, 2014, Black Hills Power filed a Motion for Approval of Settlement Agreement (SDSTA), requesting the approval of a contract with deviations with the South Dakota Science and Technology Authority ("SDSTA"). On September 18, 2014, the Commission entered an Order deferring until later in the process the approval of the contract with deviations between Black Hills Power and SDSTA. As an alternative to approving the contract with deviations at that time, the Commission conditionally authorized and approved implementation of the contract with deviations rates on an interim basis, commencing on October 1, 2014.

The Parties have been able to resolve all issues between them in this proceeding and have entered into this Stipulation, which, if accepted and ordered by the Commission, will determine the rates to result from Black Hills Power's Application. The Parties recognize that the Commission has granted intervention to BHII and DRA. The Intervenors are not parties to this Stipulation.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving the issues between them in Docket No. EL14-026. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Stipulation, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1) Upon execution of the Stipulation, the Parties shall file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2) This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any material changes in or conditions to this Stipulation which are unacceptable to either Party, this Stipulation may, at the option of either Party, be withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3) This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void, and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; neither Party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; neither Party shall be deemed to have approved, accepted, agreed, or consented to any ratemaking principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be advantaged or prejudiced or bound thereby in any other current or future rate proceeding before the Commission. Neither Party nor a representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission

relating to this Stipulation as precedent in any other current or future rate proceeding or any other proceeding before the Commission.

4) The Parties to this proceeding stipulate that all prefiled testimony, exhibits, and workpapers will be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Commission Staff would have filed direct testimony and Black Hills Power would have filed rebuttal testimony responding to certain of the positions contained in the testimony of Commission Staff.

5) It is understood that Commission Staff enters into this Stipulation for the benefit of all of Black Hills Power's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that the total revenue deficiency is $6,890,746. The Parties agree that Black Hills Power's tariffs will be designed to produce an increase in annual base rate levels of $6,890,746 or approximately 4.35% of total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. The Parties agree to a 7.76% rate of return on rate base.

2. Tariffs

The Parties have agreed to revised tariffs and those tariffs are attached as Exhibit 1 to this Stipulation for presentation to the Commission.

The Parties agree that the rate design to be set forth in the revisions to Black Hills Power's tariffs are just and reasonable and provide for the movement of each customer class toward its associated cost of service. The Parties agree that the increase in rates for electric service will be allocated to the affected rate classes resulting in increases as shown on attached Exhibit 2. The Parties agree that the rates agreed to by the Parties result in just and reasonable rates for all of Black Hills Power's South Dakota customers.

The Parties agree that the revised rate schedules shall be implemented for service rendered on and after March 1, 2015, with the bills prorated so that usage prior to October 1, 2014, is billed at the previous rates, and usage on and after October 1, 2014, is billed at the new rates.

3. Interim Rate Refund

Interim rates were implemented on October 1, 2014. Approval of this Stipulation will authorize a rate increase less than the interim rate level in effect. Black Hills Power agrees to refund customers a portion of the interim rates collected during the period October 1, 2014, through the effective date of new rates, plus interest. Attached hereto as Exhibit 3 is the Interim Rate Refund Plan. The form of the Customer Notice is attached hereto as Exhibit 4.

4. Depreciation Expense

The Parties agree that the depreciation lives and rates presented in this rate case will be the ones in effect with the approval of this Stipulation. The depreciable life of the Cheyenne Prairie Generating Station is 40 years with a depreciation rate of 2.98%.

5. Decommissioning Expense

The Parties agree that the total company decommissioning cost of $9,930,958 is included in the Decommissioning amortization identified in the 10th element of the Stipulation below and included in the revenue requirement. This amount includes the cost of decommissioning the Ben French, Neil Simpson I, and Osage coal-fired generation facilities, and does not include any contingency. The Parties agree that Black Hills Power may seek recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers.

6. Rate Case Expense

The Parties agree that a total of $212,861 in rate case expense associated with Docket EL14-026 is included in the Rate Case Expense amortization identified in the 10th element of the Stipulation below and included in the revenue requirement. Actual rate case expenses incurred in excess of this amount will be recoverable in the next Black Hills Power rate case to the extent those expenses are deemed necessary and reasonable.

7. Economic Development

The Parties agree that economic development expenses up to $100,000 shall be equally shared by shareholders ($50,000) and customers ($50,000). The economic development expenses shall include, but not be limited to, all South Dakota labor, expenses, and monetary contributions. This program will begin on October 1, 2014, and shall continue thereafter until revised by the Commission. Black Hills Power will submit, on an annual basis, no later than March 1st of each year beginning in 2015, for Commission approval a filing which describes the cost, design, and benefit of Black Hills Power's economic development programs. Program costs will be reported on a calendar year basis. Any portion of the annual customer contribution that remains unspent at the end of a program year shall be carried over into the next program year for Commission approval of expenditures or refund. No carry over shall occur for amounts spent annually in excess of $100,000. This agreement does not preclude Black Hills Power from spending more on economic development nor does it restrict Black

Hills Power from asking for modification of these economic development terms in its next general rate filing.

8. Cheyenne Prairie Generating Station Compliance Report

Black Hills Power agrees to file an informational report by February 28, 2015, on the remaining Cheyenne Prairie Generating Station capital projects, specifically the auxiliary boiler, testing, site finish work, and internal closeout labor.

9. Major Maintenance Accrual

The Parties agree to define major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

10. Amortization

The Parties agree that amortizations being recovered in rates under the terms of the Stipulation include the following where the cost (SD Amount Amortized) will be deferred and amortized over the periods shown:

Item	SD Amount Amortized ($)	Amortization Period (years)	SD Annual Amount
Rate Case Expense	$625,657	3	$208,552
Decommissioning	$14,685,070	10	$1,468,507
Winter Storm Atlas	$3,157,426	10	$315,743
69 kV LIDAR Surveying	$320,533	5	$64,107

a. Rate Case Expense

The Parties agree that the unamortized actual rate case expenses from Dockets EL12-061 and EL12-062 will be combined with the current actual rate case expenses from Docket EL14-026 and will be deferred, amortized and recovered over three (3) years. The Parties agree that the average unamortized balance of $369,191 will be included as a component of rate base. As a result of the Parties' agreement on the treatment of rate case expenses in this Stipulation, the Commission's approval of the treatment of rate case expenses in Dockets EL12-061 and EL12-062 is superseded upon approval of this Stipulation.

b. Decommissioning

The Parties agree that the net book value, inventory, and decommissioning costs associated with the Ben French, Neil Simpson I, and Osage coal-fired generation facilities will be deferred, amortized and recovered over ten (10) years. The Parties agree that the unamortized balance of $12,482,309 will be included as a component of rate base.

c. Winter Storm Atlas

The Parties agree that the incremental costs associated with Winter Storm Atlas and the South Dakota System Line Inspection will be deferred, amortized, and recovered over ten (10) years. The Parties agree that the unamortized balance of $2,683,812 will be included as a component of rate base.

d. 69 kV LIDAR Surveying Project

The Parties agree that the 69 kV LIDAR surveying costs will be deferred, amortized and recovered over five (5) years. The Parties agree that the unamortized balance of $154,093 will be included as a component of rate base.

11. Pension Expense

The Parties agree that pension expense should be normalized. A five year normalization period was used in this case. The Parties agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization method unreasonable.

12. Final Approval of Contracts with Deviations

The Parties agree that the contract with deviations, as filed on September 4, 2014, between Black Hills Power and SDSTA that is the subject of the Commission's Order Conditionally Authorizing and Approving Implementation of Contracts with Deviations, should be finally approved by the Commission without condition, and agree to support their final approval without condition.

13. Moratorium

A. The Parties agree that Black Hills Power shall not file any rate application for an increase in base rates which would go into effect prior to October 1, 2016; provided, this restriction would not prevent Black Hills Power from filing for a base rate increase to take effect prior to October 1, 2016, if Black Hills Power's cost of service is expected to increase due to an "Extraordinary Event." The Parties agree that this rate moratorium does not apply to any rider or other adjustment mechanism, including, but not limited to, the Energy Cost Adjustments, Environmental Improvement Adjustment, Transmission Facility Adjustment, Energy Efficiency Solutions Adjustment, and Phase In Plan Rate.

B. As used in this Stipulation "Extraordinary Event" is any one of the following occurrences:

1) *Governmental Impositions* – Changes in federal, state or local governmental requirements or governmental charges including, but not limited to, income taxes, taxes, charges or regulations imposed on energy, emissions, environmental externalities, or reclamation requirements imposed after October 1, 2014, upon Black Hills Power that are projected to cause its South Dakota cost of service to increase by $1,000,000 or greater.

Increases in Black Hills Power's South Dakota cost of service that are less than $1,000,000 will be presumed not to be material for the purposes of this paragraph.

2) *Major Capital Additions* – New capital projects with individual budgets greater than $10,000,000.

3) *Loss of a Major Customer* – Black Hills Power is expected to lose $2,000,000 or more of annual revenue from a single customer's accounts.

4) *Loss of Power Supply* – Black Hills Power loses power available from its power generation or purchase power contracts in an amount of 10 megawatts or more for a period forecasted to be at least six (6) months in duration.

This Stipulation is entered into effective this 8th day of December, 2014.

BLACK HILLS POWER, INC.

By: Kyle W White
Kyle White
Its: V.P. of Regulatory Affairs

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

By: Karen E. Cremer
Karen E. Cremer
Its: Staff Attorney

Exhibits to Settlement Stipulation

Exhibit 1	Tariffs
Exhibit 2	Allocation of Rate Increase
Exhibit 3	Interim Rate Refund Plan
Exhibit 4	Form of Customer Notice

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation (Settlement) of December 8, 2014, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. This Memorandum supports Staff's view of the settlement. Staff Witness Dave Peterson's direct testimony addresses specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of BHP's filing and information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in BHP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues. Staff believes the settlement is based on sound regulatory principles and avoids additional costly and unnecessary litigation.

The Parties agree BHP's revenue deficiency is approximately $6,890,746, which results in an approximate 4.35% increase in retail revenue. This revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of BHP's South Dakota jurisdictional revenue requirement.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with total Company test year costs for the twelve months ended September 30, 2013, and allocates those total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for known and measurable post-test year changes. Staff Exhibit___(BAM-1), Schedule 3 illustrates Staff's determination of BHP's *pro forma* operating income under present rates. Staff Exhibit___(BAM-2), Schedule 2 illustrates Staff's calculation of BHP's South Dakota retail rate base, and Staff Exhibit___(BAM-1), Schedule 2 and Staff Exhibit___(BAM-2), Schedule 1 summarize the positions. Staff Exhibit___(BAM-1), Schedule 1 summarizes Staff's determination of BHP's revenue deficiency and total revenue requirement collected through base rates.

The base revenue increase by rate schedule is shown on Staff Exhibit___(PJS-2), Schedule 1. Staff Exhibit___(PJS-2), Schedules 2-1 through 2-5 reflect the settlement base rates for each rate schedule. The comparison between present and settlement rates and resulting bill impacts for the Residential Service rate schedules is shown on Exhibit___(PJS-2), Schedule 3.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average Rate Base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, September 30, 2012, through September 30, 2013.

CPGS Plant Addition – BHP proposed an adjustment to increase plant in service for projected capital costs associated with the Cheyenne Prairie Generating Station (CPGS). The Company included in rate base the actual costs incurred as of December 31, 2013, and estimates of the remaining completion costs. The settlement determination revises the Company's adjustment to reflect actual costs as of October 31, 2014, and reasonably known and measurable changes after October 31, 2014. The settlement also reflects the associated accumulated deferred income taxes. The net effect of these changes is to reduce rate base by approximately $2,156,000.

Test Year Plant In Service Annualization – The Company proposed an adjustment to annualize test year non-revenue producing plant additions that were completed during the test year. The settlement determination revises the Company's adjustment to: 1) Remove the amounts related to eight projects that appear to be revenue producing; and 2) Reduce the amounts related to two projects for contributions made by CenturyLink. The settlement also includes accumulated deferred income taxes arising from these projects. The net effect of these changes is to reduce rate base by approximately $90,000.

Post-Test Year Plant Additions – The Company proposed an adjustment to increase South Dakota test year plant in service for projected non-revenue producing post-test year capital additions anticipated to be in service prior to October 1, 2014. The settlement determination revises the Company's adjustment to reflect actual costs for completed projects in-service as of November 6, 2014. The settlement also includes accumulated deferred income taxes on the post-test year plant additions that are reflected in rate base. The net effect of these changes is to increase rate base by approximately $423,000.

Ben French, Neil Simpson I, & Osage Retirements – BHP proposed an adjustment to remove from rate base the amounts related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Accumulated Depreciation – The Company proposed an adjustment to increase accumulated depreciation (and thereby to reduce rate base) to reflect one-half of the annual depreciation expense associated with new assets and its new depreciation rates. The settlement revises the Company's adjustment to synchronize the depreciation reserve with the plant additions that are to be included in rate base and to reflect a depreciation rate of 2.98% for CPGS in lieu of the Company's proposed 3.29% rate. The net effect of these changes is to increase rate base by approximately $44,000.

Cash Working Capital – BHP's proposed rate base included an allowance for cash working capital based on a lead-lag analysis. A lead-lag analysis examines the timing of the Company's receipt of service revenues from customers in relation to the Company's payment of expenses to vendors and employees. The Company's cash working capital allowance also included a rate base deduction for tax collections which the Company receives in advance of turning the related payments over to the taxing authorities. Staff carefully examined BHP's revenue lag and expense lead day determinations and made the following modifications, which are consistent with Staff adjustments in prior rate cases:

1. Revised the expense lead days for net payroll, service/holding company charges, other operating and maintenance, FICA, federal income tax, gross receipts tax, federal withholding, and sales tax;
2. Included a separate expense lead for vacation pay;
3. Included a separate expense lead for incentive compensation;
4. Included a separate expense lead for uncollectible accounts expense;
5. Revised revenue lag days to remain consistent with past Staff practice and state statute, and to more accurately reflect the South Dakota jurisdictional revenue lag; and
6. Revised expenses per day to incorporate into the lead-lag analysis the impacts of Staff's recommended adjustments to *pro forma* operating expenses.

These modifications increase rate base by approximately $5,161,000.

Rate Case Expense – Rate case expense included in Docket EL12-061, which includes costs incurred for both Docket EL12-061 and EL12-062 as of July 2, 2013, was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the Docket EL12-061 rate case expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, all amortized over a three-year period. BHP also proposed an unamortized amount of $750,046 be included in rate base. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014, for docket EL14-026 and $412,797 in actual, unrecovered costs for EL12-061 and EL12-062, for a total amount of $625,657. One-half of the rate case costs, or $369,191, is included in rate base, representing the average unamortized balance over the three year period. The net effect of these changes reduces rate base by approximately $381,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs, if any, associated with docket EL14-026 in BHP's next rate case.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the Environmental Protection Agency (EPA)'s National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In

Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants into a regulatory asset account.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of these three generating plants over five years and include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement removes all contingencies that had been included in BHP's decommissioning estimates, revises the amount included for obsolete inventory to agree with the amount removed from working capital, amortizes the regulatory asset over ten years, and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,806,000.

Storm Atlas Regulatory Asset – Winter Storm Atlas (Atlas) occurred October 3-5, 2013, causing the worst outages in BHP's 130-year history. Heavy snow and high winds, combined with fully leafed trees, caused significant damage to BHP facilities and left as many as 41,800 customers without power. Repairing this widespread damage far exceeded BHP's normal storm-related costs. In Docket EL13-036, the Commission issued an order allowing BHP to use deferred accounting for costs incurred as a result of Atlas.

In this docket, BHP proposed to include actual costs through December 31, 2013 arising from Atlas, as well as costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection driven by Atlas. BHP proposed to amortize these costs over five years and to include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only the incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,566,000.

Tax Return True-up – BHP's proposed test year allowance for income taxes included "true-up" adjustments to eliminate certain tax events that were recorded during the test year but which were related to periods prior to the test year. It is important to purge from test year operating results for transactions that relate to periods outside of the test year. Therefore, Staff accepts BHP's Tax Return True-up adjustments. Those adjustments are included in the Settlement revenue requirement determination.

NOL Adjustment – Over the past several years, bonus depreciation previously approved by Congress significantly increased BHP's annual tax deductions. The increased deductions, however, exceeded BHP's income resulting in a tax loss. Because of the tax loss position, BHP was not able to utilize all of its allowable deductions in the year they were earned. It had recorded deferred taxes relating to these tax deductions, nevertheless. The accumulated deferred taxes are used as an offset to BHP's rate base. Therefore, it was necessary to adjust BHP's rate base to reflect the unused tax deductions. BHP will now be able to utilize more of its previously unused tax deductions given the revenue increase agreed to by the Parties. The impact of this greater utilization of tax deductions on BHP's rate base has been reflected in the settlement revenue requirement. The result of recalculating this adjustment to reflect the effect of other adjustments incorporated in the settlement is to increase rate base by approximately $641,000.

Other Working Capital – BHP proposed this rate base adjustment to accurately reflect recent investments in a spare transformer for Neil Simpson II, in spare fan motors at the Neil Simpson Complex, in critical spare parts at Cheyenne Prairie Generating Station, and in a new coal stockpile at the Neil Simpson Complex, while removing the test year inventories at the recently retired Ben French, Neil Simpson I, and Osage generating units. The settlement accepts this adjustment while modifying for actual costs and reflecting a more recent 13-month average for materials and supplies, fuel stocks, and customer advances. These modifications increase rate base by approximately $969,000.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system, and BHP proposed to amortize costs associated with the project over five years and to include the unamortized balance, or four-fifths of the cost, in rate base. The settlement reflects a reduction for accumulated deferred income taxes associated with the project, an update to actual project costs and actual contributions from joint owners, and includes the average unamortized balance, or one-half of the cost, in rate base. The result of Staff's revisions reduces rate base by approximately $399,000.

Customer Service Model – This Staff proposed adjustment reflects the rate base reduction for BHP's customer service model changes. With the Belle Fourche and Newell customer service and electric operation service centers being consolidated and moved to Spearfish and Sturgis, respectively, the Newell office is no longer needed. Removing the remaining amounts associated with the Newell office reduces rate base by approximately $9,000.

Sturgis Office & Operations Center – BHP built a new service center in Sturgis to consolidate operations and business offices into one location in the northern hills. As a result, the two existing facilities in Sturgis will be closed. The settlement removes the amounts related to these two facilities as they are no longer needed. This adjustment reduces rate base by approximately $308,000.

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses, including employee additions. The settlement includes a rate base adjustment associated with one-half of the amount of annual employee salaries charged to capital projects. This adjustment increases rate base by approximately $79,000.

Other Rate Base Reductions – The Company's filing included *pro forma* rate base reduction for: 1) the flow-through of the income tax benefit associated with the repairs deduction that should not be included in rate base; 2) deferred taxes and federal effect of the state NOL that should be removed from rate base since South Dakota does not impose a state income tax; 3) deferred tax liability associated with regulatory asset – unit of property account that should not be included in rate base since the amount in the regulatory asset – unit of property is not included in rate base; and 4) the addition of accumulated deferred income tax associated with the plant that is allocated to BHP from BHSC and BHUH because the assets allocated to BHP are included in rate base. The settlement accepts this adjustment.

OPERATING INCOME

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses. These adjustments included 1) using 01/28/2014 annualized payroll as a starting point as it was the most recent payroll at the time BHP completed its adjustment; 2) removing the labor costs associated with Neil Simpson I plant personnel who will have part of their time charged to power plants not owned by BHP at the Neil Simpson Complex; 3) a 2014 union wage increase of 3.25%, a 2014 non-union wage increase of 3.50%, a partial year of a 3.5% 2015 union wage increase, and a partial year of a 3.5% 2015 non-union increase; 5) adding the costs associated with open vacancies and additional employees needed for operations; and 6) removing costs associated with employee eliminations.

Staff agreed with the Company's adjustment, except for the amounts included for the 2014 non-union and 2015 union and non-union wage increases and employee additions. The settlement revises the Company's adjustment to 1) reflect a 2014 non-union wage increase of 3.25% in lieu of the Company's proposed budgeted 3.5%; 2) reflect a full year of the 2015 union wage increase of 3.25% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; 3) reflect a full year of the 2015 non-union wage increase of 3.0% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; and 4) reflect employee additions for actual employees hired, including only the portion of employee salaries charged to O&M and adjusting the salaries for the 2015 wage increases. This adjustment reduces operating expenses by approximately $130,000.

Black Hills Corp. / Black Hills Utility Holdings Intercompany Charges – BHP proposed a $2.3 million adjustment to total company test year expenses for charges billed to it from Black Hills Utility Holdings (BHUH) (Adjustment H-5). Staff objected to this adjustment because it did not reflect a known and measurable change in BHP's costs; rather, it was merely BHP's estimate of future costs. Consistent with the Parties' treatment of other operating expenses, including expenses billed to BHP by BHSC, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, excluding amounts associated with vegetation management and reflecting an annualization for customer records and collection expenses associated with a change in allocation factors. The *pro forma* utility holdings costs also reflect an annualization of wage increases for both 2014 and 2015. The effect of these changes is to increase South Dakota operating expenses by approximately $527,000.

Employee Pension & Benefits Adjustment – BHP proposed a $334,319 total company adjustment to test year employee benefits expenses (Adjustment H-6). Within this adjustment, BHP normalized its test year pension expense by averaging the annual expense over the past five years. This normalization adjustment reduced the test year pension expense by $508,454 on a total company level. Staff agreed to BHP's pension expense normalization adjustment if it is to be applied consistently in future rate cases. Staff disagreed with the remainder of BHP's proposed employee benefits adjustment because it is based on estimated future costs rather than known cost changes. The settlement reflects known post-test year changes in employee benefits costs rather than BHP's estimates. It also reflects a normalized level of pension costs based on a five-year average of BHP's actual pension expense. The effect of these changes is to reduce South Dakota operating expenses by approximately $289,000.

Bad Debt Analysis – BHP proposed an adjustment to decrease bad debt expenses based on a three year uncollectible rate average. The settlement decreases bad debt expense based on a five year uncollectible rate average applied to retail revenues. The net effect of this change increases jurisdictional operating expense by approximately $6,000.

Generation Dispatch & Scheduling – BHP proposed an adjustment to update costs for generation dispatch and scheduling in accordance with the Generation Dispatch and Energy Management

Agreement (GDEMA) which allocates costs to the parties contracting for services based on total capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year-end August 2014 costs, while allowing known and measurable increases to labor and labor overhead. Staff also corrected errors to the capacities provided for Black Hills Power and Black Hills/Colorado Electric. The result of Staff's revisions reduces jurisdictional operating expense by approximately $106,000.

Energy Cost Adjustment Expense Elimination – The Company proposed an adjustment to remove all costs that are collected through the Energy Cost Adjustment (ECA) from the test year. The settlement accepts this adjustment.

Neil Simpson Complex Shared Facilities – BHP proposed an adjustment to update revenues and expenses for shared facilities in accordance with the Neil Simpson Complex Shared Facilities Agreement which allocates revenues and expenses to the parties based on net capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual costs. The result of Staff's revisions reduces jurisdictional operating expense by approximately $74,000 and reduces jurisdictional operating revenue by approximately $136,000.

Removal of Unallowed Advertising – BHP proposed an adjustment to remove advertising expenses that should not be recovered from ratepayers. The settlement accepts this adjustment and further removes additional advertising costs which do not contribute to the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. The effect of this adjustment reduces operating expenses by approximately $4,000.

Power Marketing Adjustment – BHP's adjustment to remove power marketing expenses from the base rate regulated cost of service is found on Statement H, Schedule H-12. The revenue adjustment found in Statement I, page 1, removes the corresponding power marketing revenues from the base rates. The settlement revises the expense adjustment to correct the labor-bonus costs removed and accepts the revenue adjustment. The effect of this adjustment reduces operating expenses by approximately $9,000.

Rate Case Expense – Rate case expense included in Docket EL12-061 (consisting of costs related to Docket EL12-061 and EL12-062) was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, amortized over a three-year period. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014 for docket EL14-026 and $412,797 in actual, unrecovered amounts for EL12-061 and EL12-062, for a total three-year amortization allowance of $625,657. The net effect of these changes is a reduction in operating expenses by approximately $188,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs associated with docket EL14-026 in the next rate case filing.

Vegetation Management Expense – BHP proposed to adjust its test year vegetation management expenses to reflect the amount approved in the stipulation in Docket EL12-061. The settlement accepts this adjustment with a slight modification which updates the allocator to conform to what BHP filed in its Statement N. The result of Staff's revision increases jurisdictional operating expense by approximately $1,000.

CPGS O&M – The Company proposed an adjustment to reflect projected operation and maintenance expense for CPGS during a normal year. The settlement reflects the Company's proposed adjustment, less reagent costs which are recovered through the ECA. This adjustment reduces operating expenses by approximately $28,000.

Ben French Severance Expense – BHP proposed an adjustment to remove the employee severance expense associated with the Ben French plant. The settlement accepts this adjustment.

Neil Simpson Complex Common Steam Allocation – BHP proposed an adjustment to update costs for the operation and maintenance of Neil Simpson Complex common steam facilities where BHP is responsible for costs relating to the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year end August 2014 costs, while allowing known and measurable increases to labor and benefits. Staff also corrected errors in the capacity shares provided for Black Hills Power and MDU, City of Gillette & Other. The result of Staff's revisions reduces jurisdictional operating expense by approximately $243,000.

Ben French, Osage, & Neil Simpson I O&M Elimination – BHP proposed an adjustment to remove the test year operating and maintenance expenses related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Future Track Workforce Development – BHP proposed a $721,861 total company expense adjustment (Adjustment H-19) to implement its eight-year Future Track Workforce Development Program. Included in the Company's proposal was a request to defer as a regulatory asset for future recovery all costs associated with the program that exceed the amount included in base rates.

Staff objected to the Company's proposal, both as to the expense to be included in base rates and to BHP's proposal to defer expenses in the future. The Parties agreed to reflect in rates BHP's actual costs for newly hired employees under the Future Track program, without deferrals. The effect of this change is to decrease South Dakota operating expenses by approximately $344,000. The settlement also eliminates the annual reporting requirements proposed in BHP's filing.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system. BHP's share is amortized over five years to correspond with the expected frequency of the survey. Staff's adjustment reflects actual costs of the survey and actual contributions from the joint owners. The result of Staff's revision reduces jurisdictional operating expense by approximately $66,000.

Customer Service Model Adjustment – This adjustment reflects the cost reductions BHP achieved as a result of their customer service model changes. The Belle Fourche and Newell customer service and electric operation services centers were consolidated and moved to Spearfish and Sturgis, respectively. This adjustment removes the salaries and benefits of three customer service representatives and eliminates Belle Fourche and Newell facility costs. The settlement also removes further costs associated with telephone, janitorial labor, and depreciation expense. The result of Staff's revision reduces jurisdictional operating expense by approximately $7,000.

Remove City of Gillette – BHP proposed an adjustment to remove the City of Gillette revenue as it relates to replacement energy. The associated costs are removed as part of the Power Marketing adjustment. The settlement accepts this adjustment.

Unbilled Revenue and Provision for Rate Refunds – Unbilled Revenue reflects an accounting accrual made each month to reflect a portion of the current month usage which is billed in the following month. These accrual entries are reversed out the following month. Provision for Rate Refunds reflects the balance related to interim rates in Dockets EL12-061 and EL12-062. These adjustments remove the entire per books amounts from these two accounts to reflect normal levels. The settlement accepts these adjustments.

Removal of Energy Cost Revenue – The Company proposed an adjustment to remove revenue associated with the ECA as associated energy costs were also removed from the test year. The settlement accepts this adjustment.

PIPR Rate Annualization – The test year revenues contain only a portion of the Phase In Plan Rate revenues established in Docket EL12-062. This known and measurable adjustment is needed to reflect the proper level of revenue and properly match what customers were paying at the end of the test year, thus reducing the revenue deficiency. The settlement accepts this adjustment.

Weather Normalization – BHP's filing contained a weather normalization adjustment of ($644,705). Staff undertook an independent weather normalization analysis and concluded that an adjustment of ($264,403) would be appropriate. Staff's adjustment updated BHP's data to reflect the latest NOAA weather normals for the thirty year base period 1981-2010. Staff also included June in the analysis of cooling load sensitivity, and measured sensitivity in absolute value as a departure from normal, rather than relative variation from monthly normals. Sensitivity was based on regression coefficients correlating usage with departure from normal. BHP accepted Staff's adjustment for settlement purposes. The effect of these changes increases operating revenues by approximately $380,000.

Industrial Contract Service Accrual – BHP proposed this known and measurable adjustment to properly match revenues with test year usage for three of their industrial customers on contract rates. The settlement accepts this adjustment.

EL12-061 Rate Increase Annualization – The test year revenues are based on the rates established in Docket EL09-018; however, rates were changed in Docket EL12-061, effective October 1, 2013. This is a known and measurable change to test year operating results. BHP proposed this adjustment to reflect the proper level of revenue to be received from customers based on the recently approved rates. The settlement accepts this adjustment.

Interest Synchronization – The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historical test year rate base as adjusted for known and measurable changes.

Depreciation Expense – In its March 31, 2014 rate filing, BHP claimed a total company depreciation expense allowance of $3,035,046 related to the Cheyenne Prairie Generating Station based on the then-estimated $92,250,624 total company plant investment at its expected in-service date of October 1, 2014. The expense allowance reflected a composite depreciation accrual rate of 3.29% that assumed a 35-year life span for the plant, allowances for retirements of plant components during the life span and an estimate of removal costs amounting to 4% of the plant investment at the time of its retirement.

The settlement reduces the CPGS depreciation allowance by $349,819 to $2,685,227, on a total company level, to reflect BHP's agreed-upon actual investment in the plant and a composite depreciation accrual rate of 2.98%. The 2.98% composite rate was derived by extending the assumed life span of CPGS from 35 years to a more realistic 40 years judging by life estimates made by other utilities for combined cycle generating units. Other parameters reflected in the 2.98% rate (interim retirements and removal costs) are consistent with the parameters reflected in BHP's existing depreciation accrual rates for its other generating facilities.

The settlement further revises the Company's depreciation adjustment to reflect the effect of the other plant adjustments included in the settlement. The net effect of these changes is to decrease South Dakota jurisdictional operating expenses by approximately $87,000.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants to a regulatory asset.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. The settlement removes all contingencies, revises the amount included for obsolete inventory to agree with the amount removed from working capital, and amortizes the regulatory asset over ten years, reducing the annual South Dakota amortization expense by approximately $1,651,000. BHP may track the actual costs incurred and seek recovery, in a future rate case, of decommissioning costs not recovered from customers.

Storm Atlas Regulatory Asset – BHP proposed to include its actual Atlas-related costs through December 31, 2013, and its estimated costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection necessitated by Atlas. BHP proposed to amortize these costs over five years. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years. The net effect of these changes is to reduce the annual South Dakota amortization expense by approximately $512,000.

Charitable Contributions – The settlement removes approximately $16,000 in charitable contributions.

Storm Damage – The settlement normalizes storm damage costs to a five-year average. As Atlas was the only major storm event in 2013 and its costs are recovered in a separate adjustment, this normalization adjustment would need to include $0.00 for the 2013 expense, and Staff was concerned that using $0.00 would not reflect an accurate value of normal storm damage expense. Thus, Staff chose the 2008 through 2012 timeframe for this adjustment and increased operating expense by approximately $31,000.

Incentive Compensation – BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from the affiliate service company. For settlement purposes, the Parties agreed that incentive compensation paid for achieving financial performance goals will be excluded from BHP's South Dakota revenue requirement. This adjustment reduces South Dakota operating expenses by approximately $666,000.

Economic Development – The Company proposed 100% recovery of economic development expenses included in the test year. The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. The adjustment reduces operating expenses by approximately $27,000.

Association Dues – The settlement removes approximately $6,000 in association dues costs associated with donations, lobbying, and various other activities that do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers.

Custer to Hot Springs Cooperatives Revenues – BHP has a joint ownership agreement with Rushmore Electric and its two members, Black Hills Electric Cooperative and Butte Electric Cooperative, for the co-owned portions of the 69 kV sub-transmission system. Rushmore Electric Power Cooperative, on behalf of itself and its members, pays BHP a monthly fee to ensure that customers of all parties are fairly and accurately responsible for their use of the jointly owned facilities. The settlement includes an adjustment to account for the additional annual revenues BHP will receive associated with the Custer to Hot Springs line. The effect of this adjustment is to increase operating revenues by approximately $90,000.

Workers Compensation – During discovery, BHP proposed an adjustment to normalize workers compensation costs to a five-year average of the costs. The settlement accepts this adjustment, increasing operating expenses by approximately $172,000.

Black Hills Corp./ Black Hills Service Co. Intercompany Charges – BHP's filed case included test year expenses billed to it by its affiliate service company, approximately $20.4 million, without adjustment. Consistent with the parties' treatment of other operating expenses, including expenses billed to BHP by BHUH, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, except for property insurance which is BHP's actual costs for the year October 2014 through September 2015. The pro forma service company costs also reflect an annualization of wage increases for both 2014 and 2015. The net effect of these changes is to increase South Dakota operating expenses by approximately $1,132,000.

Income Tax Adjustment – The Company's filing included pro forma adjustments to income tax for true-up items and items that are not part of the regulated operations of BHP that should therefore not be included in the computation of federal income tax. The settlement accepts this adjustment.

COST OF CAPITAL AND RATE OF RETURN

BHP's initial filing sought an overall rate of return of 8.48 percent, which included an embedded debt cost of 6.45 percent and a capital structure of 53.32 percent equity and 46.68 percent debt. The requested rate of return on equity was 10.25 percent. Staff's analysis initially challenged all three components of the overall rate of return: (1) embedded cost of debt, (2) the capital structure, and (3) the required return on equity.

[Begin Confidential] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[End Confidential]**, the settlement overall rate of return is 7.76 percent.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. The settlement position reached between Staff and BHP is discussed below.

Class Cost of Service/Spread of the Increase – BHP's filed case included a class cost of service study ("CCOSS"). A CCOSS is useful in assigning revenue responsibility to each rate class that BHP serves in

South Dakota and in designing rates within each class. The allocation methods reflected in BHP's CCOSS are basically the same as those that were reflected in previous CCOSS studies filed by BHP and accepted by Staff and the Commission. In this proceeding, however, BHP introduced the results of a new customer load study based primarily on data obtained from the Company's new AMI meters. The new load data was used in developing the class demand allocation factors used in the CCOSS. The new load data incorporated into the CCOSS indicated that base rates for two of the five customers classes should be increased significantly (Residential – 19.26% and General Service Large/Industrial Contract – 15.44%); base rates to the Water Pumping/Irrigation class should be increased by a small amount (3.45%); and base rates for the remaining two classes should be decreased (General Service – 6.37% and Lighting Service – 15.74%). Rather than implementing these indicated rate changes, BHP proposed a rate moderation plan to avoid adverse rate impacts to the Residential and General Service Large/Industrial Contract customers. Under BHP's moderation plan, no class is to pay less than 75 percent of the system-wide percentage increase and no class is to pay more than 120 percent of the system-wide percentage increase.

Without agreeing specifically with either the results of the CCOSS or BHP's underlying new load research results, the Parties agreed to accept BHP's proposed rate moderation plan by implementing a 75% to 120% percent collar around the system-wide percentage increase. Under this approach, the following class increases result:

Settlement Class Revenue Increases

Class	Percent Increase
Residential	5.04%
General Service	3.46%
General Service Large/Industrial Contract	4.55%
Water Pumping/Irrigation	3.11%
Lighting Service	3.45%
Total	**4.35%**

Rate Design (Residential Customer Service Charge) – BHP's currently effective monthly customer service charge for the Residential class is $8.75. BHP proposed to increase the present rate to $10.00. In settlement, the parties agreed to increase the Residential monthly customer service charge to $9.25. This represents a 5.71 percent increase in that charge, which is within the range agreed to among the parties for the Residential class as a whole. Staff also believes that a $9.25 monthly service charge is supported by the underlying costs to serve Residential customers.

OTHER ISSUES

Economic Development – The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. Under the terms of the settlement the following conditions apply:

- $100,000 total paid equally by ratepayers ($50,000) and shareholders ($50,000);

- Expenses shall include but not be limited to, all South Dakota labor, expenses and monetary contributions deemed to be a benefit to economic development in the BHP South Dakota electric territory;
- On an annual basis, no later than March 1 of each year, BHP will submit for the Commission's approval a filing that describes the actual cost, design and individual benefits of each cost to BHP's Economic Development programs in the previous calendar year and the projected cost, design and individual benefits of each cost to BHP's Economic Development programs in the current calendar year;
- The Commission may determine that some of the programs are not appropriate for purposes of 50% rate recovery;
- If the remaining programs cost less than $100,000 at the end of a program year, the unspent costs shall be "carried over" into the next program year for Commission approval of expenditure or refund; and
- No carry-over shall occur for any amounts spent annually in excess of $100,000.

Energy Cost Adjustment – The Company proposed the following change to the Fuel and Purchased Power Adjustment (FPPA), which is a component of the ECA: 1) to include any difference in ad valorem or property taxes from what is reflected in base rates; 2) to credit 100% of the Company's wholesale contract revenue on October 1, 2014, as agreed to in Docket No. EL12-062; 3) to eliminate the power marketing credit minimum; and 4) to recover 100% of the costs related to short-term planning reserve capacity purchases and sales. Staff agreed with items 1, 2, and 4, but took issue with the elimination of the power marketing credit minimum. The Parties agreed for settlement purposes to reduce the power marketing credit minimum from $2 million to $1 million and increase the power marketing sharing from 65% to 70%.

Major Maintenance Accrual – BHP requested approval of a modification to the major maintenance account to expense a portion of the plant overhaul costs each year based on a plant's planned maintenance cycle. In Docket EL09-018, the settlement allowed BHP to establish a major maintenance account and a regulatory liability for steam plant maintenance and a 7-year cycle was established. The work previously done during the seven year overhaul is now split into two overhauls. There is no change in the existing accrual at this time. The settlement defines major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

Implementation of Rates – The tariffs shown on Exhibit 1 attached to the Settlement are to be implemented for service rendered on or after March 1, 2015. Customer bills will be prorated so that usage prior to October 1, 2014, is billed at BHP's previously effective rates (i.e., the base rate in effect immediately prior to the interim rates implemented on October 1, 2014), and usage on and after October 1, 2014, is to be billed at the new rates established by the settlement.

Interim Rate Refund – Interim rates were implemented on October 1, 2014. Approval of the Settlement will authorize a rate increase less than the interim rate level. The Company agrees to refund customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014 through February 28, 2015. As part of the refund, BHP will include interest, calculated by applying a 7% annual interest to the average refund balance for each month that interim revenues were collected. The Company's Interim Rate Refund Plan is attached to the Settlement as Exhibit 3.

Contract with Deviations – On September 4, 2014, BHP filed a Contract with Deviations between BHP and SDSTA. The Commission approved this Contract with Deviations on an interim basis. Now that the cost of service and class cost of service study review is complete, Staff and BHP agree the Contract with Deviations may now be finally approved by the Commission, without condition.

RECOMMENDATION

Staff recommends the Commission approve the Settlement for the reasons stated above.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**AMENDED SETTLEMENT STIPULATION** **EL14-026**

It is hereby stipulated and agreed by and among Black Hills Power, Inc. ("Applicant" or "Black Hills Power") and the South Dakota Public Utilities Commission Staff ("Staff") (jointly "Party" or "Parties"), that the following Amended Settlement Stipulation ("Amended Stipulation") may be adopted by the South Dakota Public Utilities Commission ("Commission") in the above-captioned matter. In support of its Application for Authority to Increase Its Electric Rates ("Application"), the Parties do hereby offer this Amended Stipulation, the Application and all supporting materials filed March 31, 2014, and thereafter.

I. INTRODUCTION

On March 31, 2014, Black Hills Power filed with the Commission the aforementioned Application through which it requested authority to increase annual revenues by approximately $14.6 million.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (collectively "BHII") filed a Petition to Intervene. On the same date, Dakota Rural Action ("DRA") also filed a Petition to Intervene. The Commission issued its Order Granting Intervention to BHII and DRA on June 26, 2014.

On September 4, 2014, Black Hills Power filed a Motion for Approval of Settlement Agreement, requesting the approval of a contract with deviations with the South Dakota

Science and Technology Authority ("SDSTA"). On September 18, 2014, the Commission entered an Order deferring until later in the process the approval of the contract with deviations between Black Hills Power and SDSTA. As an alternative to approving the contract with deviations at that time, the Commission conditionally authorized and approved implementation of the contract with deviations rates on an interim basis, commencing on October 1, 2014.

The Parties have been able to resolve all issues between them in this proceeding and have entered into this Amended Stipulation, which, if accepted and ordered by the Commission, will determine the rates to result from Black Hills Power's Application. The Parties recognize that the Commission has granted intervention to BHII and DRA. The Intervenors are not parties to this Amended Stipulation.

II. PURPOSE

This Amended Stipulation has been prepared and executed by the Parties for the sole purpose of resolving the issues between them in Docket No. EL14-026. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Amended Stipulation, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1) Upon execution of the Amended Stipulation, the Parties shall file this Amended Stipulation with the Commission together with an amended joint motion requesting that the Commission issue an order approving this Amended Stipulation in its entirety without condition or modification.

2) This Amended Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any material changes in or conditions to this Amended Stipulation which are unacceptable to either Party, this Amended Stipulation may, at the option of either Party, be withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3) This Amended Stipulation shall become binding upon execution by the Parties, provided however, that if this Amended Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void, and privileged. This Amended Stipulation is intended to relate only to the specific matters referred to herein; neither Party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; neither Party shall be deemed to have approved, accepted, agreed, or consented to any ratemaking principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Amended Stipulation, or be advantaged or prejudiced or bound thereby in any other current or future rate proceeding before the Commission. Neither Party nor a representative thereof shall directly or indirectly refer to this Amended Stipulation or that part of any order of the Commission relating to this Amended Stipulation as precedent in any other current or future rate proceeding or any other proceeding before the Commission.

4) The Parties to this proceeding stipulate that all prefiled testimony, testimony given at the hearing, exhibits, and workpapers will be made a part of the record

in this proceeding. The Parties understand that if this matter had not been settled, Commission Staff would have filed further direct testimony and Black Hills Power would have filed rebuttal testimony responding to certain positions contained in the direct testimony of Commission Staff.

5) It is understood that Commission Staff enters into this Amended Stipulation for the benefit of all of Black Hills Power's South Dakota customers affected by this docket.

III. ELEMENTS OF THE AMENDED SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that the total revenue deficiency is $6,890,746. The Parties agree that Black Hills Power's tariffs will be designed to produce an increase in annual base rate levels of $6,890,746 or approximately 4.35% of total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. The Parties agree to a 7.76% rate of return on rate base.

2. Tariffs

The Parties agreed to revised tariffs and those tariffs are attached as Exhibit 1 to the original Stipulation, filed December 9, 2014, for presentation to the Commission. The Parties agree to file compliance tariffs with the Commission approved effective date.

The Parties agree that the rate design to be set forth in the revisions to Black Hills Power's tariffs are just and reasonable and provide for the movement of each customer class toward its associated cost of service. The Parties agree that the increase in rates for electric service will be allocated to the affected rate classes resulting in increases as shown in Exhibit 2, attached to the original Stipulation filed on December 9, 2014. The Parties agree that the rates agreed to by the Parties result in just and reasonable rates for all of Black Hills Power's South Dakota customers.

The Parties agree that the revised rate schedules shall be implemented for service rendered on and after the Commission approved effective date, with the bills prorated so that usage prior to October 1, 2014, is billed at the previous rates, and usage on and after October 1, 2014, is billed at the new rates.

3. Interim Rate Refund

Interim rates were implemented on October 1, 2014. Approval of this Amended Stipulation will authorize a rate increase less than the interim rate level in effect. Black Hills Power agrees to refund customers a portion of the interim rates collected during the period October 1, 2014, through the effective date of new rates, plus interest. The Parties agree to file revisions to the Interim Rate Refund Plan and the Customer Notice, attached as Exhibits 3 and 4 to the original Stipulation, filed December 9, 2014, to reflect the Commission's final decision.

4. Depreciation Expense

The Parties agree that the depreciation lives and rates presented in this rate case will be the ones in effect with the approval of this Amended Stipulation. The depreciable life of the Cheyenne Prairie Generating Station is 40 years with a depreciation rate of 2.98%.

5. Decommissioning Expense

The Parties agree that the total company decommissioning cost of $9,930,958 is included in the Decommissioning amortization identified in the 10th element of the Amended Stipulation below and included in the revenue requirement. This amount includes the cost of decommissioning the Ben French, Neil Simpson I, and Osage coal-fired generation facilities, and does not include any contingency. The Parties agree that Black Hills Power may seek recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers.

6. Rate Case Expense

The Parties agree that a total of $212,861 in rate case expense associated with Docket EL14-026 is included in the Rate Case Expense amortization identified in the 10th element of the Amended Stipulation below and included in the revenue requirement. Actual rate case expenses incurred in excess of this amount will be recoverable in the next Black Hills Power rate case to the extent those expenses are deemed necessary and reasonable.

7. Economic Development

The Parties agree that economic development expenses up to $100,000 shall be equally shared by shareholders ($50,000) and customers ($50,000). The economic development expenses shall include, but not be limited to, all South Dakota labor, expenses, and monetary contributions. This program will begin on October 1, 2014, and shall continue thereafter until revised by the Commission. Black Hills Power will submit, on an annual basis, no later than April 1st, 2015, and March 1st of each year beginning in 2016, for Commission approval a filing which describes the cost, design, and benefit of Black Hills Power's economic development programs. Program costs will be reported on a calendar year basis. Any portion of the annual customer contribution that remains unspent at the end of a program year shall be carried over into the next program year for Commission approval of expenditures or refund. No carry over shall occur for amounts spent annually in excess of $100,000. This agreement does not preclude Black Hills Power from spending more on economic development nor does it restrict Black Hills Power from asking for modification of these economic development terms in its next general rate filing.

8. Cheyenne Prairie Generating Station Compliance Report

Black Hills Power agrees to file an informational report by April 1, 2015, on the remaining Cheyenne Prairie Generating Station capital projects, specifically the auxiliary boiler, testing, site finish work, and internal closeout labor.

9. Major Maintenance Accrual

The Parties agree to define major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

10. Amortization

The Parties agree that amortizations being recovered in rates under the terms of the Amended Stipulation include the following where the cost (SD Amount Amortized) will be deferred and amortized over the periods shown:

Item	SD Amount Amortized ($)	Amortization Period (years)	SD Annual Amount
Rate Case Expense	$625,657	3	$208,552
Decommissioning	$14,685,070	10	$1,468,507
Winter Storm Atlas	$3,157,426	10	$315,743
69 kV LIDAR Surveying	$320,533	5	$64,107

a. Rate Case Expense

The Parties agree that the unamortized actual rate case expenses from Dockets EL12-061 and EL12-062 will be combined with the current actual rate case expenses from Docket EL14-026 and will be deferred, amortized and recovered over three (3) years. The Parties agree that the average unamortized balance of $369,191 will be included as a component of rate base. As a result of the Parties' agreement on the treatment of rate case expenses in this Amended Stipulation, the Commission's approval of the treatment of rate case expenses in Dockets EL12-061 and EL12-062 is superseded upon approval of this Amended Stipulation.

b. Decommissioning

The Parties agree that the net book value, inventory, and decommissioning costs associated with the Ben French, Neil Simpson I, and Osage coal-fired generation facilities will be deferred, amortized and recovered over ten (10) years. The Parties agree that the unamortized balance of $12,482,309 will be included as a component of rate base.

c. Winter Storm Atlas

The Parties agree that the incremental costs associated with Winter Storm Atlas and the South Dakota System Line Inspection will be deferred, amortized, and recovered over ten (10) years. The Parties agree that the unamortized balance of $2,683,812 will be included as a component of rate base.

d. 69 kV LIDAR Surveying Project

The Parties agree that the 69 kV LIDAR surveying costs will be deferred, amortized and recovered over five (5) years. The Parties agree that the unamortized balance of $154,093 will be included as a component of rate base.

11. Pension Expense

The Parties agree that pension expense should be normalized. A five year normalization period was used in this case. The Parties agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization method unreasonable.

12. Final Approval of Contracts with Deviations

The Parties agree that the contract with deviations, as filed on September 4, 2014, between Black Hills Power and SDSTA that is the subject of the Commission's Order Conditionally Authorizing and Approving Implementation of Contracts with Deviations, should be finally approved by the Commission without condition, and agree to support their final approval without condition.

13. Moratorium

A. The Parties agree that Black Hills Power shall not file any rate application for an increase in base rates which would go into effect prior to January 1, 2017; provided, this restriction would not prevent Black Hills Power from filing for a base rate increase to take effect prior to January 1, 2017, if Black Hills Power's cost of service is expected to increase due to an "Extraordinary Event." The Parties agree that this rate moratorium does not apply to any rider or other adjustment mechanism, including, but not limited to, the Energy Cost Adjustments, Environmental Improvement Adjustment, Transmission Facility Adjustment, Energy Efficiency Solutions Adjustment, and Phase In Plan Rate.

B. As used in this Amended Stipulation "Extraordinary Event" is any one of the following occurrences:

1) *Governmental Impositions* – Changes in federal, state or local governmental requirements or governmental charges including, but not limited to, income taxes, taxes, charges or regulations imposed on energy, emissions, environmental externalities, or reclamation requirements imposed after October 1, 2014, upon Black Hills Power that are projected to cause its South Dakota cost of service to increase by $1,000,000 or greater.

Increases in Black Hills Power's South Dakota cost of service that are less than $1,000,000 will be presumed not to be material for the purposes of this paragraph.

2) *Major Capital Additions* – New capital projects with individual budgets greater than $10,000,000.

3) *Loss of a Major Customer* – Black Hills Power is expected to lose $2,000,000 or more of annual revenue from a single customer's accounts.

4) *Loss of Power Supply* – Black Hills Power loses power available from its power generation or purchase power contracts in an amount of 10 megawatts or more for a period forecasted to be at least six (6) months in duration.

This Amended Stipulation is entered into effective this 10th day of February, 2015.

BLACK HILLS POWER, INC.

By: Kyle White jt
Kyle White

Its: V.P. Regulatory Affairs

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

By: Karen E. Cremer
Karen E. Cremer

Its: Staff Attorney

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING
AMENDED SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Amended Settlement Stipulation (Amended Settlement) of February 10, 2015, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. On January 15, 2015, Staff filed David E. Peterson's direct testimony that addressed specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony. On January 15, 2015, BHP submitted rebuttal testimony.

The hearing was held as scheduled on January 27-28, 2015, with Staff, BHP, BHII, and DRA appearing and presenting evidence and argument. At the conclusion of the hearing, the Commission decided to defer taking action on the outstanding issues until its regular meeting on March 2, 2015. On January 29, 2015, the Commission issued a Post-Hearing Procedural Order.

OVERVIEW OF AMENDED SETTLEMENT

Upon hearing arguments from the Parties and the Intervenors and weighing Commission concerns at the hearing, Staff and BHP found it in the best interest of all the Parties to work toward an amended settlement, which would correct the utility holdings allocation oversight presented by BHII. Staff and BHP held a settlement meeting on February 6, 2015, to address this concern. As a result, some party positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a resolution of the issue. The following describes the changes from the originally filed Settlement.

Utility Holdings Allocation Oversight Correction

As shown on Staff Exhibit___(DEP-2), Schedule 1, the amended cost of service corrects the South Dakota allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Corporation/Black Hills Utility Holdings intercompany charges adjustment, reducing the revenue requirement by $286,041. Thus, the Amended Settlement corrects the initial oversight.

Wyodak Operations and Maintenance Adjustment

The Amended Settlement accepts the $412,988 Wyodak O&M adjustment as provided by BHP in Exhibit JTR-1. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. This represents a known and measurable increase to test year expense.

Cash Working Capital, NOL Adjustment, Interest Synchronization, Bad Debt Adjustment

The Amended Settlement uses the same calculation for these adjustments as the Settlement filed on December 9, 2014. However, the revenue requirement value of each adjustment changes based on the resolution of various issues in the case. These adjustments are dependent on the pro forma rate base, expenses and revenues, and were recalculated as a result of the Utility Holdings allocation correction and the Wyodak O&M adjustment.

No Change to Revenue Deficiency

Although Exhibit___(BAM-4), Schedule 1 of the amended cost of service shows a $7,010,894 revenue deficiency, the revenue deficiency in the Amended Settlement will remain at the $6,890,746 level provided in the original Settlement. Thus, the amended cost of service more than supports the revenue requirement agreed upon in the Amended Settlement, and ratepayers will not incur the added rate case expense required to prepare revised rates and tariff sheets.

Additional Moratorium

The Amended Settlement extends the stay-out provision an additional three months from what was agreed to in the original Settlement. Thus, BHP shall not file any rate application for an increase in base rates which would go into effect prior to January 1, 2017. This addition would provide a calendar year test year, should BHP file for an increase at the expiration of the moratorium.

RECOMMENDATION

Staff recommends the Commission approve the Amended Settlement for the reasons stated above.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

DOCKET NO. EL14-026

TESTIMONY OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

JANUARY 15, 2015

EXHIBIT
STAFF 1
006368

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

DOCKET NO. EL14-026

TESTIMONY OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is David E. Peterson. I am a Senior Consultant employed by Chesapeake Regulatory Consultants, Inc. ("CRC"). Our business address is 1698 Saefern Way, Annapolis, Maryland 21401-6529. I maintain an office in Dunkirk, Maryland.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I graduated with a Bachelor of Science degree in Economics from South Dakota State University in May of 1977. In 1983, I received a Master's degree in Business Administration from the University of South Dakota. My graduate program included accounting and public utility courses at the University of Maryland.

In September 1977, I joined the Staff of the Fixed Utilities Division of the South Dakota Public Utilities Commission as a rate analyst. My responsibilities at the South Dakota Commission included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric, gas and telephone utilities.

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, wastewater, and steam utilities in connection with utility rate and certificate proceedings before federal and state regulatory commissions.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes. I have presented testimony in 146 other proceedings before the state regulatory commissions in Alabama, Arkansas, California, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

In addition, in 2006 I testified twice before the Energy Subcommittee of the Delaware House of Representatives on consolidated tax savings and income tax normalization. Also in 2006, I presented a one-day seminar to the Delaware Public Service Commission ("Commission") on consolidated tax savings, tax normalization and other utility-related tax issues. In the spring of 2011, I co-presented along with Mr. Scott Hempling, the then-director of NRRI, a three-day seminar on public utility ratemaking principles to the Commissioners and Staff of the Washington Utilities and Transportation Commission. In 2012, I presented a one-day seminar on cost allocation and rate design to the Colorado Office of Consumer Counsel. More recently, I presented a three-day seminar on utility ratemaking, revenue requirements, cost allocation and rate design to the Delaware Public Service Commission Staff.

II. SUMMARY

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this proceeding is on behalf of the South Dakota Public Utilities Commission Staff ("Commission Staff").

Q. HAVE YOU TESTIFIED IN OTHER PROCEEDINGS BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION?

A. Yes, I have. I testified in a number of electric and natural gas distribution rate proceedings when I was on the Commission Staff during the period 1977 through 1980. More recently, I have assisted the Commission Staff in several rate proceedings, including those involving Black Hills Power, Inc. ("BHP" or "the Company"), wherein the issues were resolved by settlements. However, I filed testimony on behalf of the Commission Staff in Docket No. EL12-046 involving a rate increase request filed by Northern States Power Company and in Docket No. NG12-008 involving a rate increase request filed by Montana-Dakota Utilities Co.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was asked to present the Commission Staff's support for the Settlement Stipulation reached by the Commission Staff and BHP. The Settlement Stipulation is intended to resolve all of the issues in this proceeding. My testimony also addresses certain issues raised in the testimonies presented by witnesses for the Black Hills Industrial Intervenors[1] ("BHII").

[1] Members of the Black Hills Industrial Intervenors include GCC Dakotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc. and Wharf Resources (U.S.A.), Inc.

Q. BEFORE YOU BEGIN DISCUSSING THE SETTLEMENT STIPULATION AND BHII'S ISSUES, PLEASE PROVIDE A BRIEF SUMMARY OF BHP'S RATE REQUEST IN THIS PROCEEDING.

A. BHP currently provides electric service to approximately 65,500 customers within Rapid City and other western South Dakota communities under rates approved by the South Dakota Public Utilities Commission ("the Commission"). BHP is a wholly-owned subsidiary of Black Hills Corporation ("BHC"). BHC also owns other regulated natural gas and electric utility companies operating in Colorado, Iowa, Kansas, Montana, Nebraska and Wyoming. BHC also owns non-regulated companies that generate wholesale electricity, that produce natural gas and crude oil and that mine coal.

BHP's base (i.e., non-fuel) electric rates that were in effect at the time that the Company initiated the instant proceeding were those that were approved by the Commission at the conclusion of BHP's last base rate proceeding in Docket No. EL12-061. BHP's 2012 rate proceeding was filed using an adjusted test year ended June 30, 2012. BHP had initially requested a $13.745 million annual revenue increase in that case. However, the Commission approved a settlement agreement that authorized BHP to increase annual revenues by approximately $8.831 million, effective October 1, 2013.

On March 31, 2014, BHP filed an application with the Commission seeking to increase base electric rates by approximately $14.634 million, or 9.27 percent, to be effective October 1, 2014. This effective date was chosen by the Company to coincide with the expected in-service date of the Cheyenne Prairie Generating Station ("CPGS"). BHP is a co-owner of the CPGS. BHP's current rate request was calculated from a Company-prepared revenue requirement study that relied on a test year ended September 30, 2013. On October 1, 2014, BHP placed its proposed rates into effect on an interim basis. BHP's interim rates will remain in effect until the conclusion of this proceeding.

III. SETTLEMENT STIPULATION

Q. ARE YOU THE ONLY ONE THAT ANALYZED BHP'S RATE REQUEST FOR THE COMMISSION STAFF?

A. No. The Commission Staff assembled a team of in-house analysts (Brittany Mehlhaff, Patrick Steffensen and Eric Paulson) and three outside consultants, including myself, to analyze BHP's rate increase application. The other two outside consultants are my colleagues at CRC, Robert Towers and Basil Copeland, Jr. This is essentially the same team that analyzed BHP's 2012 filing as well. Together, the Commission Staff team invested literally hundreds of hours analyzing BHP's Application, Testimony, Exhibits, Filing Statements and Workpapers. In addition, the Commission Staff propounded approximately 330 requests to BHP for additional data and information. Each response was carefully reviewed and analyzed by one or more Staff analyst. In addition, the Commission Staff carefully reviewed and analyzed information provided by BHP in response to BHII's approximately 60 discovery requests.

The Commission Staff began its investigation shortly after the Commission officially noticed BHP's rate increase Application on April 3, 2014. That investigation continued until late October 2014 when settlement discussions between the Commission Staff, BHP, BHII and another intervenor, Dakota Rural Action ("DRA")[2], commenced. Settlement discussions continued through

[2] DRA did not file testimony in this proceeding but did participate in settlement discussions that were held.

November and into the beginning of December. Ultimately, the Commission Staff and BHP reached a negotiated settlement that is intended to resolve all of the issues arising in this proceeding. A Settlement Stipulation, signed on December 8, 2014, by representatives of the Commission Staff and BHP, memorializes the terms of the settlement. BHII and DRA chose not to join the settlement. Concurrent with the filing of my testimony, the Commission Staff is also filing a Staff Memorandum Supporting Settlement Stipulation ("Staff Memorandum"). The Staff Memorandum carefully summarizes all of the Commission Staff's adjustments that are factored into the agreed-upon settlement revenue increase.

Q. WOULD IT BE FAIR TO CHARACTERIZE THE AGREEMENT REACHED BETWEEN BHP AND THE COMMISSION STAFF AS A "BLACK BOX" SETTLEMENT?

A. No. Any such characterization of the settlement would be wrong. A black box settlement typically is one where the specific resolution of issues cannot be identified. This is not what occurred in this proceeding, however. Rather, the Commission Staff prepared a detailed calculation of BHP's test year rate base, revenues and expenses, including known and measurable post-test year changes. The Commission Staff revenue requirement determination identified differences that it had with certain rate base, revenue and expense claims made by the Company and issues raised by the Commission Staff that were not mentioned in the Company's filing. The Commission Staff also carefully considered the issues and adjustments proposed by BHII in confidential settlement discussions. The end result of the Commission Staff's analyses is the Staff Memorandum, and the supporting schedules, which detail how the Commission Staff arrived at and can justify the $6,890,746 revenue deficiency reflected in the Settlement Stipulation. That document stands on its own and there is no need for me to explain in my testimony each Commission Staff adjustment. The points that I am trying to make in this discussion, however, are that the Commission Staff carefully considered all of the issues raised in this proceeding by BHP and the BHII and that the Staff Memorandum provides the Commission and the other parties a transparent roadmap showing how the Commission Staff determined that the agreed-upon annual revenue increase, $6,890,746, is consistent with South Dakota Law, prior Commission practices, and sound ratemaking principles and results in just and reasonable rates. It is for these reasons that I recommend the Commission approve the Settlement Stipulation and the terms contained therein.

In the following sections of my testimony I address certain claims made by witnesses for the BHII, who did not join in the Settlement Stipulation.

IV. BHII'S REVENUE REQUIREMENT TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF LANE KOLLEN ON BEHALF OF THE BHII?

A. Yes, I have.

Q. WERE YOU AWARE OF THE ISSUES RAISED BY MR. KOLLEN PRIOR TO SEEING HIS TESTIMONY?

A. Generally, yes. I was not aware of the specific details of each adjustment that Mr. Kollen recommends prior to him filing testimony, but substantially all of the issues he raises were identified and discussed in settlement discussions held earlier in this proceeding and were considered by the Commission Staff.

Q. BEGINNING AT PAGE 7 OF HIS DIRECT TESTIMONY, MR. KOLLEN DISCUSSES GENERAL RATEMAKING PRINCIPLES WHICH HE

ACKNOWLEGES FORM THE BASIS FOR MANY OF HIS RECOMMENDED ADJUSTMENTS. PLEASE COMMENT ON THE GENERAL RATEMAKING PRINCIPLES THAT HE DISCUSSES.

A. Mr. Kollen identifies and recommends the following three principles:

1. The Commission should limit any post-test year adjustment to the twelve-month period immediately following the historical test year ended September 30, 2013.

2. The Commission should reject proposed post-test year increases in various expenses that are not justified and that the Company did not demonstrate were necessary and appropriate.

3. The Commission should reject adjustments that are not consistent with Commission precedent or policy, that are not justified, and that the Company did not demonstrate were necessary and appropriate.

Initially, while I am unable to discern a difference between Mr. Kollen's second and third principles, I can find no fault in either principle. In fact, I believe that the Commission Staff's revenue requirement, as described in detail in the Staff Memorandum, is faithful to both principles.

Ironically, Mr. Kollen's first principle is inconsistent with his third. It is my understanding that the Commission's long-standing policy has been to consider post-test year adjustments up to twenty-four months, not twelve months, beyond the end of the test year provided they are known with reasonable certainty and measureable with reasonable accuracy. Indeed such a treatment is, in effect, mandated to the Commission by South Dakota Administrative Rule 20:10:13:44. In addition to ignoring the twenty-four month look-out provision, Mr. Kollen apparently interprets this administrative rule to require that any costs that are beyond twelve months post-test year must be accompanied by projected changes in revenue for the same period. This is not how the Commission and the

Commission Staff have interpreted this rule, however. Rather, it is my understanding that both the Commission Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers) a corresponding revenue adjustment must also be recognized. It is for this reason that the Settlement Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Settlement Stipulation. Therefore, the Settlement Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. By the same token, the adjustments recommended by Mr. Kollen that do not reflect this principle as I have described it are inconsistent with long-standing Commission policy.

Q. CONCERNING THE ADJUSTMENTS THAT MR. KOLLEN RECOMMENDS, ARE ANY OF THAT ARE ALREADY REFLECTED IN THE SETTLEMENT STIPULATION?

A. Yes. Many of Mr. Kollen's recommended adjustments already are addressed in the manner described in the Staff Memorandum and are part of the agreed-upon revenue requirement by the Commission Staff and BHP. These adjustments include the following:

1. Double-count of CPGS spare parts inventory (eliminated in settlement);
2. Decommissioning regulatory asset (contingency allowance in original cost estimate has been removed by settlement);
3. Decommissioning regulatory asset (ten-year amortization reflected in settlement).

4. Storm Atlas regulatory asset deferred income taxes (corrected in settlement);
5. Retired steam plants amortization (ten-year amortization period reflected in settlement);
6. Storm Atlas regulatory asset amortization (ten-year amortization period reflected in settlement);
7. CPGS depreciation (depreciation rate reflects 40-year life span);
8. FutureTrack Workforce Program (all costs were excluded in settlement and no deferrals will be made. Rather, only the cost of employees actually hired to date are reflected in settlement); and
9. Employee additions (only the cost of employees actually hired to date are reflected in the settlement).

Q. MR. KOLLEN TESTIFIES THAT IT IS IMPROPER TO INCLUDE THE NET OPERATING LOSS ("NOL") ASSET IN RATE BASE. DO YOU AGREE?

A. No, I do not. As explained in the Staff Memorandum, over the past several years, "bonus" depreciation previously authorized by Congress significantly increased BHP's annual tax deductions. The sum of BHP's tax deduction, including the new bonus depreciation deductions, however, exceeded its taxable revenues, which resulted in an NOL for tax purposes. Because of the tax loss position, BHP was not able to utilize all of its allowable tax deductions in the year they were earned. Consistent with accounting requirements, it had recorded deferred taxes relating to these tax deductions, nevertheless. The corresponding accumulated deferred tax liability is used as an offset or reduction to BHP's rate base. Without an adjustment, BHP's rate base would be reduced (via the deferred tax liability offset) by more than the tax benefit that the Company has realized to date because of the unused tax deductions. Therefore, it is necessary to adjust BHP's rate base to reflect the unused tax deductions. The specific adjustment reflected in BHP's rate base is a deferred tax asset, to which Mr. Kollen objects. Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements.

The U.S. Tax Code Section 168 (i) (9) concerning the Accelerated Cost Recovery System that is now being used by BHP and other utilities to determine depreciation-related tax deductions provides as follows:

(9) Normalization rules

(A) In general

In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—

(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

(ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

(B) Use of inconsistent estimates and projections, etc.

(i) In general: One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).

(ii) Use of inconsistent estimates and projections: The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

In this instance, a violation identified in paragraph (B) (ii) above could result if Mr. Kollen's recommendation were to be adopted by the Commission because BHP's resulting reserve for deferred taxes for ratemaking purposes (i.e., excluding the deferred tax asset) would not match the tax benefits of the depreciation-related tax deductions that BHP has received to date because a portion of those benefits are yet unrealized due to the existence of the NOL.

Violating the IRS normalization requirements could result in the disallowance of BHP's accelerated tax depreciation deductions which will have an extremely adverse impact on South Dakota ratepayers, including members of the BHII.

Moreover, the treatment of BHP's NOL reflected in the Settlement Stipulation is the same as that approved by the Commission in BHP's last base rate case and in the base rate cases for other South Dakota utilities. For these reasons, I recommend the Commission reject Mr. Kollen's NOL rate base adjustment.

Q. WHAT WAS BHP INITIALLY REQUESTING CONCERNING ITS DECOMMISSIONING ASSETS ASSOCIATED WITH THE RETIREMENT OF THE NEIL SIMPSON I, BEN FRENCH, AND OSAGE COAL-FIRED GENERATING UNITS?

A. BHP initially proposed to amortize estimated costs, including contingency allowances, associated with the retirement and decommissioning of these three generating stations over <u>five</u> years and to include the unamortized balance in rate base.

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement removes all contingency allowances that had been included in BHP's cost estimates. It also provides for a ten-year amortization period and includes the average unamortized balance over the first three years in rate base.

Q. WHAT DOES MR. KOLLEN RECOMMEND ON THIS ISSUE?

A. Mr. Kollen objects to any rate recognition for this issue at this time. Instead, he recommends the Commission authorize BHP to defer the decommissioning costs as regulatory assets and to address recovery of the assets in the Company's next base rate case. In support of his recommendation, Mr. Kollen objects to the contingency allowance contained in BHP's cost estimate and to BHP's proposed five-year amortization period. Both of these concerns are addressed in the settlement, however. Mr. Kollen also objects to current rate recovery because he believes the decommissioning costs (1) are not known with reasonable certainty and measurable with reasonable accuracy, (2) will be incurred more than twelve months beyond the end of the test year, and (3) are not accompanied by revenue adjustments. I already discussed my issue with Mr. Kollen's interpretation of the administrative rule governing post-test year adjustments. ARSD 20:10:13:44 permits the Commission to look out twenty-four months beyond the end of the test year to recognize known and measurable revenue and cost changes; and not just the twelve months that Mr. Kollen advocates. Also, there is no revenue producing aspect to retiring the three coal-fired units. Thus, there is no merit to Mr. Kollen's second and third arguments. As for his first argument, that the decommissioning costs are not known with reasonable certainty and measurable with reasonable accuracy, again, there is no merit to Mr. Kollen's claim. The Commission Staff was comfortable with recognizing BHP's cost claims, excluding the contingency allowances, as a known change because approximately 70 percent of the estimated costs are capped by a fixed price contract for decommissioning activities. Since a majority of the costs are determined by a fixed price contract, I believe that this reasonably qualifies the adjustment as known and measurable. As for Mr. Kollen's recommendation to defer BHP's decommissioning costs until the next rate proceeding, by following that path, it is likely that BHP would not have agreed to the stay-out moratorium provision in the Settlement Stipulation. Deferring decommissioning costs also comes with a price. Unamortized decommissioning costs are included in rate base and earn a return such that future ratepayers will pay more the longer recovery is delayed. For these reasons, I support the treatment reflected in the Settlement Stipulation relating to BHP's decommissioning costs.

Q. MR. KOLLEN ALSO OBJECTS TO BHP'S PROPOSED TREATMENT OF THE 69 KV LIGHT DETECTION AND RANGING ("LIDAR") SURVEYING COSTS. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement provides for an amortization of BHP's costs associated with this project over a five-year period.

Q. WHAT ARE MR. KOLLEN'S OBJECTIONS TO RECOGNIZING THESE COSTS?

A. Mr. Kollen objects to recognizing these costs in rates because they were not incurred within twelve months following the end of the test year. Moreover, to the extent that the costs are to be amortized, Mr. Kollen recommends a ten-year amortization rather than five years as provided for in the settlement.

Q. WHAT IS YOUR RESPONSE TO MR. KOLLEN'S CONCERNS?

A. BHP expected to have incurred its LIDAR surveying costs by the end of the third quarter in 2014. This is well within the twenty-four month period the

Commission typically relies on for evaluating post-test year adjustments. Moreover, as with BHP's decommissioning costs discussed earlier in my testimony, BHP's LIDAR costs are also governed and capped by a fixed rate contract. Thus, in my opinion, the costs are sufficiently known and measurable and are appropriately recognized in rates. The five-year amortization period reflected in the settlement was determined because five years is the expected frequency for LIDAR surveying activities. Therefore, it would be inappropriate to employ a ten-year amortization period as Mr. Kollen recommends and thereby burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization simply makes more sense for these costs.

Q. WHAT DOES MR. KOLLEN RECOMMEND CONCERNING BHP'S PROPOSED ADJUSTMENT FOR PROJECTED EMPLOYEE ADDITIONS AND ELIMINATIONS?

A. Mr. Kollen recommends the Commission disallow BHP's labor-related cost adjustments because he believes the adjustments ignore the fact that BHP historically has several open positions.

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The Commission Staff shares Mr. Kollen's concern about recognizing phantom costs in rates for vacant positions. Because of this concern, the settlement includes cost allowances for only filled positions at the time of the Commission Staff's review. That is, cost allowances for vacant positions are not included in the settlement revenue requirement. This treatment should resolve Mr. Kollen's concern.

Q. HOW WAS THE PENSION EXPENSE ISSUE TREATED IN THE SETTLEMENT?

A. The following table shows BHP's pension expense over the last five years.

Table 1
BHP Annual Pension (FAS 87) Expense
2010 Through 2014

2010	**$2,925,853**
2011	**$1,819,156**
2012	**$3,251,072**
2013	**$2,709,322**
2014	**$ 976,122**
Five-year average	**$2,336,305**[3]

As shown in the table above, BHP's 2014 pension expense was unusually low when compared with the previous four years. Because of the significant variability of the expense year-to-year, BHP proposed a normalization adjustment that includes a pension expense allowance based on the average of the annual expenses over the last five years. The settlement incorporates BHP's pension normalization adjustment. The agreed-upon pension expense represents a $508,454 reduction from the test year pension expense, on a total Company basis.

Mr. Kollen considers the pension normalization adjustment "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. To support his contention, Mr. Kollen stated the Company offered no evidence that the pension expense will swing upward to the five-year average in future years.

[3] See BHP's response to Staff DR1-1; workpapers for Schedule H-6.

In truth, it is Mr. Kollen's position that is opportunistic. It is clear from the table above that BHP's pension expense can be highly variable and subject to major swings each year. Mr. Kollen's recommendation would have the Commission set rates based on BHP's lowest pension cost level in the last five years, with the knowledge based on recent experience that such costs are highly variable year-to-year. An understatement of BHP's pension costs could place the Company in a significant under-recovery position necessitating more frequent rate increases. With a highly variable cost such as the pension expense, to avoid wide swings in over-recovery and under-recovery of the underlying expense, it makes sense to employ a normalization procedure, such as that reflected in the settlement. To avoid any concern that the settlement approach is opportunistic, BHP and the Commission Staff agreed in the Settlement Stipulation to follow the five-year normalization approach for pension expense for the next five years, unless there is an extraordinary event that makes a five-year normalization method unreasonable.

Q. WHAT IS MR. KOLLEN'S CONCERN WITH INCENTIVE COMPENSATION EXPENSES?

A. Mr. Kollen believes the settlement resolution of the incentive compensation issue does not go far enough. In the settlement, $666,000 of the Company's $1.554 million total test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. In addition to this already excluded amount, Mr. Kollen would also exclude $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses. Mr. Kollen contends that these additional amounts represent incentive awards that are similar in nature to those excluded in the settlement.

I do not necessarily disagree with Mr. Kollen's characterization of the incentive awards. In fact, I had initially pursued the same issues on behalf of the

Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, I support the exclusion that is contained in the settlement and recommend that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. Of course, the Commission Staff and the BHII are free to revisit this issue in BHP's next base case given the Settlement Stipulation in this proceeding does not establish precedent on the incentive compensation issue.

Q. MR. KOLLEN OPPOSES BHP'S ADJUSTMENTS RELATING TO COSTS ALLOCATED TO IT BY TWO AFFILIATES, BLACK HILLS UTILITY HOLDINGS, INC. ("BHUH") AND BLACK HILLS SERVICE COMPANY, LLC ("BHSC"). WHAT ARE YOUR COMMENTS ON MR. KOLLEN'S CONCERNS?

A. BHP initially proposed an adjustment to test year BHUH expenses based on its post-test year operating budget. I had the same concerns as those expressed by Mr. Kollen that the adjustment lacked proper support. That is, I was not willing to recommend the Commission approve an adjustment based solely on BHP's budget projections. During our investigation, however, BHP provided a detailed summary of its most recent annualized expenses from the two affiliated companies[4]. The actual annual amounts billed to BHP are included in the settlement. Thus, the amounts billed to BHP from affiliates that are incorporated into the settlement reflect the Company's actual, known costs.

[4] See BHP's Second Supplemental Response to Staff DR3-96

Mr. Kollen also pointed out in his testimony that certain billings from BHUH were allocated to the South Dakota retail jurisdiction incorrectly on the Commission Staff's revenue requirement schedules. Mr. Kollen is correct. Properly allocating those expenses to South Dakota reduces the indicated revenue deficiency by approximately $286,000.

Q. MR. KOLLEN OBJECTS TO BHP'S PROPOSED DEPRECIATION RATE FOR THE NEW CHEYENNE PRARIE GENERATING STATION BECAUSE IT REFLECTS AN ASSUMED 35-YEAR LIFE SPAN. WHAT IS YOUR RESPONSE?

A. Commission Staff addressed this issue and the Settlement Stipulation reflects the same, longer, 40-year life span recommended by Mr. Kollen.

Moreover, it should be noted that whether it is 35 years or 40 years or some other life span, the life span that serves as the foundation for a depreciation accrual rate for CPGS *is an estimate* and a necessary departure from the principle that all elements of BHP's revenue requirement should be "known and measurable".

Q. WHY IS THAT IMPORTANT?

A. It is important because it is relevant to Mr. Kollen's other depreciation-related objections to the Settlement Stipulation – namely, the salvage estimates reflected in BHP's proposed accrual rates for other production plants and the concept of anticipating these future costs for current recovery. Beginning at page 47 of his testimony, Mr. Kollen declares that (1) the development of the salvage values are flawed and unreliable and then opines (2) that they may represent an undisclosed proposal to change the Commission's policy for recovery of retirement-related cost from after-retirement recovery to before-retirement recovery and (3) the increased negative salvage allowances are not necessary at this time because the

Commission is not required to provide for the recovery of unknown future costs in present utility service rates.

My point here is that, however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired.

Ironically, while objecting to the uncertainty of salvage estimates for other plant and advising that the Commission need not provide for the recovery of costs to be incurred in the future, Mr. Kollen is not reluctant to recommend a depreciation accrual rate for CPGS that includes an allowance for future retirement costs equal to 4 percent of that plant's capital costs as well as factoring in assumed allowances for interim retirements (see Remaining Lives by Account exhibited on the second page of Exhibit ___(LK-16); all are less than the 40-year life span by reason of interim retirements).

V. BHII'S COST ALLOCATION TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STEPHEN J. BARON ON BEHALF OF THE BHII CONCERNING CLASS COST ALLOCATION?

A. Yes, I have. In his testimony, Mr. Baron identified what he believes are several errors in BHP's class cost of service study ("CCOSS"). Based on his analyses, Mr. Baron recommended the Commission reject the Company's CCOSS. In spite of Mr. Baron's concerns with BHP's CCOSS, he nevertheless recommended the Commission approve the apportionment of the overall approved revenue increase to the rate classes as reflected in the Settlement Stipulation. Mr. Baron also recommended the Commission require BHP to file in its next base rate case a CCOSS reflecting the changes that he recommended in this case.

Q. BEFORE YOU DISCUSS MR. BARON'S RECOMMENDED CHANGES TO BHP'S CCOSS, DO YOU HAVE ANY INITIAL COMMENTS ON HIS TESTIMONY AND RECOMMENDATIONS?

A. Yes. Because the BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. This is true irrespective of the issues that Mr. Baron raises with the CCOSS. In fact, Mr. Baron's testimony is unnecessary since the Company's CCOSS is not being adopted in the Settlement Stipulation and neither the Commission Staff nor BHP is asking the Commission to accept the Company's CCOSS. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation and through Mr. Baron's testimony the BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. All parties' rights are preserved in the Settlement Stipulation to advocate different CCOSS allocation procedures in BHP's next base rate case, should they so choose.

Q. MR. BARON RECOMMENDED SEVERAL CHANGES TO BHP'S CCOSS. WHICH AMONG HIS RECOMMENDED CHANGES IS THE MOST SIGNIFICANT IN TERMS OF IMPACT ON CLASS RATES OF RETURN?

A. By far, the recommended change that has the most impact on class rates of return relative to those shown in BHP's CCOSS is the minimum distribution system ("MDS") approach. The impact is illustrated in the table below.

Table 2
Class Cost of Service Study Analysis
Comparison of Class Rates of Return

Rate Class	Column 1 BHC Results	Column 2 BHC with MDS	Column 3 BHII Adjustments
Residential	5.11%	4.47%	4.23%
General Service	9.85%	10.33%	9.98%
Combined GS Lg – Ind Contract	5.70%	6.50%	7.26%
Lighting	12.14%	12.19%	12.37%
Water pumping/irrigation	7.78%	9.10%	9.39%
Total SD retail	6.73%	6.73%	6.73%

Sources:
Columns 1,3: Baron Direct, page 26
Column 2: BHII's response to Staff DR-4

Column 1 on the table above presents class rates of return under BHP's CCOSS at existing base rates. Column 2 shows the resulting class rates of return if only the MDS change that Mr. Baron advocates is incorporated into BHP's CCOSS. Column 3 shows class rates of return if all of Mr. Baron's recommendations are adopted. Notice that the change in class rates of return between Columns 2 and 3 is not as significant as the change between Columns 1 and 2. The relative changes between the columns demonstrate the significance of the MDS approach to Mr. Baron's recommended results.

Q. WHAT IS THE MDS?

A. The MDS postulates that there are certain types of facilities that must be installed by the utility to provide customers access to the utility's electrical service, regardless of customer usage requirements. The MDS then classifies the cost of the minimum (or zero) size of these facilities as customer-related. For example, the MDS calculation relied on by Mr. Baron attempts to estimate the cost of a wooden pole that is essentially zero feet tall and then re-price the actual cost of all of the wooden poles presently in service to reflect the cost of the minimum size pole (zero feet). Using statistical techniques, the MDS study estimated that a wooden pole with zero height would cost $44.33. This amount was multiplied by the total number of wooden pole to determine the total cost of the minimum size system. The re-priced minimum size pole inventory divided by the total investment in poles produces the ratio or percentage of the Company's pole investment that Mr. Baron then classified as customer-related. The remainder of the pole investment was classified as a demand-related cost. A similar procedure was used to re-price BHP investments in underground conduit and conductors, overhead conductors, and line transformers.

Q. WHAT IS YOUR CONCERN WITH USING THE MDS TO CLASSIFY A PORTION OF DISTRIBUTION COSTS AS CUSTOMER-RELATED?

A. In general, my objection to the MDS approach is that it does not give appropriate consideration to BHP's actual system design, construction and operation. Having failed to give proper consideration to these important factors, the MDS fails to reflect BHP's cost of service.

Those who support classifying distribution facilities (other than services and meters) on a customer basis do so based on an assertion that some minimum investment is necessary to make electrical service available for each customer, regardless of the customer's peak or annual service requirements. Proponents then argue that this "customer-related" investment should be defined as either: a) the hypothetical cost of the current distribution system revalued using the cost of minimum-sized distribution facilities presently installed on the system (the MDS approach) or; b) the hypothetical cost of distribution plant having no load carrying capability (the so-called "zero-intercept" approach being advocated by Mr. Baron).

The minimum size distribution equipment that a utility will actually install, however, is based on expected customer loads and existing customer densities, not on the number of customers served by the utility or minimum service requirements. As for the zero-intercept approach, no utility installs distribution equipment incapable of carrying loads. Rather, the facilities that BHP installs are sized, designed, operated and maintained in order to meet the individual customers' peak and annual service and safety requirements. Neither the MDS nor the zero-intercept variant of the MDS gives appropriate consideration to actual system design, construction and operation. The MDS fails to reflect cost-causation and, therefore, is not a proper cost allocation method.

Q. APART FROM YOUR CONCEPTUAL ISSUES WITH THE ZERO-INTERCEPT APPROACH TO THE MDS THAT MR. BARON ADVOCATES, DO YOU HAVE ANY CONCERNS ABOUT THE MDS STUDY AND THE ZERO-INTERCEPT CALCULATIONS UPON WHICH MR. BARON RELIES?

A. Yes, I do. The concerns that I discuss below only begin to scratch the surface of the problems with the MDS calculations that may lie underneath. But, they are sufficient enough for the Commission to challenge and to reject Mr. Baron's blind reliance on the results of the MDS study.

Initially, it should be noted that neither Mr. Baron nor any one in his firm participated in preparing the MDS study upon which he relies. Nor does Mr. Baron have any knowledge of BHP's specific distribution design criteria.[5] Rather, Mr. Baron relies on a ten-year old study that BHP Colorado's former owner, Aquila, Inc., prepared for a 2004 rate case in Colorado. Mr. Baron never attempts to prove that the conditions in Colorado are similar to those in BHP's South Dakota service territory. Nor does Mr. Baron demonstrate the MDS study is equally valid today with the passage of so much time. The only support that Mr. Baron seems to offer for his use of Aquila's ten-year old MDS study is pointing to the fact that BHP itself used the same study in this case to develop the primary/secondary distribution facility split in its CCOSS.

Q. IS THAT A SUFFICIENT REASON FOR USING AQUILA'S 2004 MDS STUDY IN COLORADO IN THIS 2014 BHP SOUTH DAKOTA CASE?

A. No, it is not. While BHP used the same study to split the primary and secondary distribution facilities in its CCOSS, neither the MDS study nor BHP's CCOSS

---

[5] See BHII's response to Staff Data Request No. 7.

study and results are being adopted in this case. Mr. Baron's reliance on BHP using the same MDS study for a different purpose, therefore, is misplaced. Moreover, Mr. Baron does not have an independent basis for using that MDS study in this proceeding since it was not designed for nor does it attempt to explain the design and cost components of BHP's South Dakota service territory.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE MDS STUDY?

A. Yes. The statistics supporting the study are suspect as well. The author of the study back in 2004 used three modeled regression forms (i.e., linear, exponential, and polynomial) for each of Aquila's four distribution plant accounts that were studied. The author then chose the "best" regression form among the three. But, the only statistical parameter that he used to choose among the three modeled regression forms was R-squared. While the study employed the R-squared statistic in a consistent fashion throughout the study (i.e., always choosing the equation with the highest R-squared), in many cases the R-squared statistic was so high, and so close to the other R-squared statistics for the other regression forms, as to call into question whether meaningful statistical inferences could be obtained on the basis of R-squared alone. For example, for Account 365, Overhead Conductors, the linear model had an R-squared of 0.9984, and the polynomial model had an R-squared of 0.9994. But the intercepts (i.e., the MDS point) were quite different; the linear model had an intercept of $0.5905, and the polynomial model had an intercept that was nearly 60 percent greater at $0.9376. While the R-squared of the polynomial model was slightly higher than that of the linear model, it is possible that the difference in intercepts is not statistically significant. But we have no way of determining whether that is the case because the more relevant statistical parameters – the standard deviation of the intercepts or T-statistics – are not provided in the MDS study. This highlights a common fallacy in the use of regression models; that R-squared is a sufficient parameter for making statistical inferences. It is not. It is possible that the R-squared is low, but the regression coefficients are still statistically significant based on the standard deviations. The opposite also can be true, especially with respect to intercepts; the R-squared can be high and the intercept still not be significantly different than zero.

There is yet further indication of problems with Aquila's MDS study. Take Account 365 – Wood Poles, for example. Each of Aquila's R-squared values for this account are high, ranging between 0.9451 and 0.9981. The intercepts vary from -\$569.89 (linear model) to +\$801.43 (polynomial model). But is the intercept not statistically different from zero? We cannot answer that question because the relevant statistical parameters to evaluate this are not included in the MDS study.

The Wood Pole regression analysis points out yet another problem with this type of analysis. If you look at the graph provided in the MDS study for Wood Poles, there are no data points below a pole height of 30 feet. That is of course because pole heights of say five feet are unheard of. But the regression model assumes that such a thing really exists. The issue here is that of extrapolating out of the observed range. The NARUC Electric Cost Allocation Manual referenced by Mr. Baron in support of the MDS approach recognizes this shortcoming in the MDS approach.[6] Statistically, extrapolating out of an observed range is always questionable, and standard deviations are absolutely essential to make any kind of a meaningful inference about estimates outside the range of observations. But, this is precisely what the MDS approach requires; hypothesizing about costs that never have been, or ever will be, observed in the real world because real world

[6] See Baron Exhibit ___(SJB-3), page 13 of 17.

electrical distribution engineers do not design for minimum or zero-load conditions.

It is my understanding that the Commission has never before adopted the MDS approach for any utility in South Dakota. I am loathe to recommend the Commission adopt such a significant change in its long-standing practice based on a ten-year old study prepared by another utility in another state where the analyses are incomplete. Moreover, the author of the original study upon which Mr. Baron relies is not even a participant in this proceeding. Thus, it is not possible for the Commission Staff to ask questions about the study. In sum, the MDS study relied on by Mr. Baron raises more questions than it answers and should not be deemed reliable by the Commission for rate setting purposes.

Q. MR. BARON ALSO RAISES AN ISSUE CONCERNING ENERGY LOSS FACTORS NOT BEING REFLECTED IN BHP'S CURRENT ENERGY COST ADJUSTMENT ("ECA") FACTOR. DO YOU HAVE ANY COMMENT ON THIS?

A. I am not aware if the Commission Staff has taken a position on loss factors in connection with the ECA. Regardless, however, to the extent that the BHII feels it has a legitimate concern with this issue, it is being raised in the wrong forum. Mr. Baron acknowledges that ECA revenues and expenses are excluded in BHP's base rates. Therefore, if the BHII wishes to pursue this issue it should do so in connection with a review of BHP's ECA.

VI. CONCLUSION

Q. ON PAGE 4 OF HIS DIRECT TESTIMONY, MR. KOLLEN STATES: "AS DEMONSTRATED BELOW, THE PROPOSED SETTLEMENT BETWEEN THE COMPANY AND THE STAFF IS WOEFULLY INADEQUATE." DO YOU CARE TO COMMENT ON MR. KOLLEN'S STATEMENT?

A. Mr. Kollen's disparaging characterization of the settlement marginalizes the hundreds of hours that were devoted to the rate investigation by the Commission Staff in analyzing BHP's rate request and in crafting a resolution of all issues through a negotiated settlement. As is evident by the Staff Memorandum, the Commission Staff arrived at its settlement position based on a thorough analysis of all issues while relying on long-standing Commission practices and requirements imposed by South Dakota Administrative Rules governing ratemaking practices in the State. Obviously, there was give-and-take between the Commission Staff and BHP in settlement negotiations. Staff did not receive all that it hoped for; neither did BHP. In fact, BHP agreed to accept less than one-half (47 percent) of its original requested revenue increase. Moreover, the settling parties agreed to a stay-out provision that restricts BHP's ability to seek another base rate increase prior to October 1, 2016. The two-year rate moratorium has real value to BHP customers, including the members of the BHII.

As shown in my testimony above, the Settlement Stipulation addresses many of the revenue requirement issues that Mr. Kollen raised. Other issues raised by Mr. Kollen are inconsistent with long-standing Commission practices and the requirements of South Dakota Administrative Rules governing public utility ratemaking. And while Mr. Kollen raised some legitimate concerns with a few of his issues, those issues were addressed in confidential settlement negotiations and were part of the give-and-take therein. As for Mr. Baron's testimony, it seems unnecessary given that no party is asking the Commission to accept the Company's CCOSS and that the BHII supports the apportionment of the revenue increase to the rate classes that is reflected in the settlement. Whatever issue the BHII has with cost allocation can be addressed in BHP's next rate proceeding given that any resolution at this time will not have any impact on the outcome of this proceeding.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**FINAL DECISION AND ORDER; NOTICE OF ENTRY** **EL14-026**

PROCEDURAL HISTORY

On March 31, 2014, Black Hills Power, Inc. (BHP) filed with the South Dakota Public Utilities Commission (Commission) an Application for Authority to Increase Electric Rates (Application) and supporting exhibits requesting approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27% based on BHP's test year ending September 30, 2013.[1] The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in BHP's South Dakota service territory. The Application requested an effective date of October 1, 2014, for the proposed rate increase which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station, then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14.

On April 11, 2014, BHP filed revised Exhibits A, B, C, and D. On April 16, 2014, the Commission issued an Order Assessing Filing Fee assessing a filing fee of up to the $250,000 maximum allowed by SDCL 49-1-8 to reimburse the actual expenses incurred by the Commission in processing this docket. On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively Black Hills Industrial Intervenors or BHII) filed a Petition to Intervene, and Dakota Rural Action, Inc. (DRA) filed a Petition to Intervene. On June 18, 2014, BHP filed Black Hills Power, Inc.'s, Objection to the Intervention Petition of Dakota Rural Action and Black Hills Power, Inc.'s Response to Intervention Petition of Black Hills Industrial Intervenors.

On June 20, 2014, DRA filed Dakota Rural Action's Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene and Dakota Rural Action, Inc.'s Attachment to Paragraph 4 of Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention, granting intervention to BHII and DRA, subject to the condition that DRA file an affidavit attesting to the members of DRA who were then current customers of BHP. On June 27, 2014, DRA filed a Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

[1] The Application, Commission Orders in the case, and all other filings and documents in the record are available on the Commission's web page for Docket EL14-026 at: http://www.puc.sd.gov/Dockets/Electric/2014/EL14-026.aspx

On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates advising the Commission and the public of BHP's intent to implement its requested rate increase as of October 1, 2014. On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement and Settlement Agreement to settle outstanding issues between BHP and the South Dakota Science and Technology Authority (SDSTA Settlement Agreement). The SDSTA Settlement Agreement includes a Third Amendment to Electric Power Service Agreement Between Black Hills Power, Inc. and South Dakota Science and Technology Authority (Third Amendment). On September 10, 2014, the Commission's staff (Staff) filed a Staff Memorandum regarding the Third Amendment. On September 12, 2014, BHP filed its responses to Staff's ninth set of data requests. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement subject to the conditions set forth in the Staff Memorandum. On September 24, 2014, BHP filed a revised tariff page Section No. 3A, Sheet No. 1.

On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits (Settlement Stipulation). On December 12, 2014, the Commission issued a Scheduling Order. On December 30, 2014, the Commission issued an Order for and Notice of Hearing setting this matter for hearing on January 27-29, 2015, at the Matthew Training Center in Pierre. On December 30, 2014, BHII filed the pre-filed testimony of its witnesses Lane Kollen and Stephan J. Baron and associated exhibits. On January 15, 2015, Staff filed the pre-filed testimony of its witness David E. Peterson and a Staff Memorandum Supporting Settlement Stipulation and associated exhibits. On January 15, 2015, BHP filed the pre-filed rebuttal testimony of Kyle D. White, John J. Spanos, Jon Thurber, Christopher Kilpatrick, and Robert J. Hollibaugh. On January 20, 2015, BHP, BHII, and Staff filed exhibit and witness lists.

On January 23, 2015, BHII filed a Motion for Briefing of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (Motion) requesting that the Commission issue an order establishing a post-hearing briefing schedule and recommending a schedule to be established by such order. The hearing was held as scheduled on January 27 and 28, 2015. Following the evidentiary hearing, the Commission considered the Motion and after discussion decided upon a schedule that would permit a decision to be rendered prior to the expiration of the one-year period commencing with the date the Application was filed. On January 29, 2015, the Commission issued a Post-Hearing Scheduling Order requiring all parties' post-hearing briefs to be filed and served on or before February 17, 2015, and setting the matter for Commission action on March 2, 2015.

On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation between BHP and Staff (Amended Stipulation) reflecting two changes to the factual bases supporting the agreed revenue requirement due to new information contained in pre-filed testimony filed after the Settlement Stipulation was entered into and filed and evidence introduced at the hearing. The first change corrects an error in the South Dakota jurisdictional allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Utility Holdings (BHUH) intercompany charges adjustment, reducing the revenue requirement by $286,041. The second change reflected in the Amended Stipulation accepts the $412,988 Wyodak operations and maintenance (O&M) adjustment as provided by BHP in Exhibit BHP 71. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. This represents a known and measurable increase to test year expense. On February 10, 2014, Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation.

On February 17, 2015, BHP, BHII, and DRA filed Post-Hearing Briefs, and Staff filed a letter concurring with BHP's Post-Hearing Brief. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Settlement Stipulation. At its regular meeting on March 2, 2015, after questions by Commissioners of the parties, the Commission voted unanimously to Grant the Joint Motion for approval of Amended Settlement Stipulation between BHP and Staff and approve the terms and conditions stipulated therein as the decision of the Commission on the rate increase requested by BHP with an effective date of April 1, 2015, to approve the Settlement Agreement and contract with deviations between BHP and SDSTA, to approve the interim rate refund plan set forth as Exhibit 3 to the original Settlement Stipulation between BHP and Staff but a with refund period beginning in May 2015, and with carrying charges on refunds of 7% as stipulated between BHP and Staff in the original Settlement Stipulation. On March 5, 2015, BHP filed a Customer Notice, revised tariff sheets, and an Interim Refund Plan conforming to the Commission's action at the March 2, 2015, meeting.

FINDINGS OF FACT

Procedural Findings

1. The Procedural History set forth above is hereby incorporated by reference in its entirety in these Procedural Findings. The procedural findings set forth in the Procedural History are a substantially complete and accurate description of the material documents filed in this docket and the proceedings conducted and decisions rendered by the Commission in this matter.

Parties

2. The Applicant is Black Hills Power, Inc., a corporation organized under the laws of South Dakota. Ex BHP 1, p. 4.[2] BHP is a wholly-owned subsidiary of Black Hills Corporation. Ex BHP 9, pp. 2-3. BHP is an investor owned "public utility" as defined in SDCL 49-34A-1(12) that provides retail electric service in South Dakota. Ex BHP 1, pp. 1 and 5; Ex BHP 9, pp. 2-3.

3. On June 26, 2014, the Commission issued an Order Granting Intervention to GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) and Dakota Rural Action (DRA).

4. The BHII companies are a group of General Service, Large and Industrial Contract customers of BHP. Ex BHII 3, p. 4.

5. DRA is a member-based organization with an office located in Rapid City. Dakota Rural Action's Petition to Intervene. A number of DRA's members are customers of BHP.

[2] References to the January 27-28, 2015, Hearing Transcript are in the format "TR" followed by the Hearing Transcript page number(s) referenced, and references to Hearing Exhibits are in the format Ex followed by "BHP" for BHP exhibits, "BHII" for BHII exhibits, "Staff" for Staff exhibits, and "JT" for BHP/Staff joint exhibits followed by the exhibit number and, where applicable, the page number(s) referenced or other identifying reference and, where applicable, the attachment or sub-exhibit identifier and page number(s) referenced.

Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

6. Staff also participated in the docket as a full party.

Amended Settlement Stipulation

7. BHP's Application as filed requested approval from the Commission to increase its rates for retail electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in South Dakota. The Application requested an effective date of October 1, 2014, for the proposed rate increase, which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station (CPGS), then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14. Ex BHP 1, p. 3; Ex Staff 1, p. 4. The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. Ex BHP 1, pp. 1-2; Exs BHP 4 through 58.

8. BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and an 8.48% overall rate of return on rate base. Ex BHP 5, Exhibit G, Statement G, p. 1; Ex BHP 23, p. 3; Ex BHP 46, pp. 7-8, 11-12; Ex BHP 48; TR 269.

9. The Application also requested approval of: an accounting order allowing BHP to use deferred accounting for the costs associated with the FutureTrack Workforce Development Program that deviate from the costs included in base rates; an accounting order for the Company's Winter Storm Atlas regulatory asset if the decision in the docket was not issued by December 31, 2014; revisions to the Energy Cost Adjustment tariff; and a modification to the major maintenance account to expense a portion of the plant overhaul cost each year based on a plant's planned maintenance cycle. Ex BHP 1, p. 3; Ex BHP 8, pp. 6-7; Ex BHP 15, pp. 14-15; Ex BHP 24, pp. 5-11, 14-17; Exs BHP 25-28.

10. Beginning immediately following BHP's filing of the Application on March 31, 2014, Staff and its outside consultants conducted an extensive review of the Application and the statements, exhibits, testimony, and working papers filed with the Application. In addition, Staff served at least 330 discovery requests for additional data and information on BHP and conducted a thorough analysis of BHP's responses thereto and also its responses to approximately 60 additional discovery requests served on BHP by BHII. Exhibit Staff 1, p. 5; TR pp. 263, 267-268.

11. Staff based its determination of an appropriate revenue requirement on a comprehensive analysis of the as-filed September 30, 2013, total BHP test year costs, and the additional information obtained through discovery that supported further post-test year adjustments. In particular, Staff first allocated total company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for appropriate post-test year changes. The Amended Settlement Stipulation incorporates numerous income adjustments and rate base adjustments. Ex Staff 1; Staff Memorandum Supporting Settlement Stipulation (Staff Memorandum); Staff Memorandum Supporting Amended Settlement Stipulation (Amended Staff Memorandum).

12. Settlement discussions between Staff, BHP, BHII, and DRA commenced in late October, 2014. Thereafter, Staff and BHP held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. According to Staff's expert witness Peterson, substantially all of the issues raised by BHII's witness, Lane Kollen, were identified and discussed in such settlement discussions and were considered by Staff in its analysis and its negotiation of the Settlement Stipulation. Ex Staff 1, p. 8. Ultimately, Staff and BHP reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA did not elect to become parties to the Settlement Stipulation reached between BHP and Staff. Ex Staff 1, pp. 5-6. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. Exs JT 1-6.

13. In the Settlement Stipulation, BHP and Staff agreed that BHP's total revenue deficiency is $6,890,746 and that BHP's tariffs will be designed to produce an increase in annual base revenue levels of $6,890,746 or approximately 4.35% over total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. In the Settlement Stipulation, BHP and Staff agreed to a 7.76% rate of return on rate base. Ex JT 2, p. 4. A detailed explanation of the adjustments, data, analyses, and computations underlying the Settlement Stipulation's provisions to resolve the numerous matters at issue in this case between BHP and Staff is set forth in Staff's Memorandum in Support of Settlement Stipulation filed on January 15, 2015, together with the pre-filed testimony of Staff's expert witness, David E. Peterson, set forth in Ex Staff 1.

14. On February 10, 2015, following the filing of BHII's pre-filed testimony, Staff's pre-filed testimony, and BHP's pre-filed rebuttal testimony and the evidentiary hearing held on January 27-28, 2015, BHP and Staff jointly filed an Amended Settlement Stipulation, and Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation. On February 23, 2015, BHP and Staff jointly filed a Joint Motion for Approval of Amended Settlement Stipulation. The Amended Stipulation seeks to correct an error in the South Dakota allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Corporation/Black Hills Utility Holdings intercompany charges adjustment, reducing the revenue requirement by $286,041. This error was brought to light in the pre-filed and hearing testimony of BHII witness Kollen and was acknowledged to be correct by Staff witness Peterson in his pre-filed testimony and in his hearing testimony. TR 163-164, 184; Ex BHII 1, p. 39-40; Ex BHP 70, p. 16; Ex Staff 1, p. 19.

15. A second change reflected in the Amended Stipulation involves the acceptance and inclusion of an expense adjustment of $412,988 for the South Dakota jurisdictional share of Wyodak generating plant O&M expenses as provided by BHP in its pre-filed testimony after the Settlement Stipulation was executed and filed. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. Ex BHP 70, pp. 17-19; Ex BHP 71. This represents an increase to test year expense that was not known and measurable at the time the Settlement Stipulation was executed and filed but had become known and measurable at the time BHP's pre-filed rebuttal testimony exhibits were filed and became known and measurable prior to twenty-four months after the Application filing date. Ex BHP 70, pp. 17-19.

16. The Amended Stipulation uses the same calculation for cash working capital, net operating loss, interest synchronization, and bad debt adjustments as the Settlement

Stipulation. The revenue requirement value of each adjustment changes, however, based on the resolution of various issues in the case. These adjustments are dependent on the pro forma rate base, expenses, and revenues, and were recalculated as a result of the BHUH allocation correction and the Wyodak O&M expense adjustment. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

17. Although the Staff Memorandum in Support of Amended Settlement Stipulation Exhibit___(BAM-4) Schedule 1 – Amended Settlement SD Electric Revenue Requirement cost of service calculations show a revenue deficiency of $7,010,894, the revenue deficiency in the Amended Stipulation, Section III, ¶1 retains the $6,890,746 level provided in the original Settlement Stipulation. With the inclusion of the Wyodak O&M costs, the amended cost of service in the Amended Stipulation supports a revenue requirement greater than that agreed upon in the Amended Stipulation, and ratepayers will not incur the added rate case expense required to prepare revised rates and tariff sheets. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

18. In addition to the inclusion of only a portion of the Wyodak O&M expense adjustment in rates agreed to in the Amended Stipulation and the maintenance of the total rate increase at the same amount as in the Settlement Stipulation, Section III, ¶13 extends the rate case filing moratorium provision an additional three months from what was agreed to in the Settlement Stipulation. Under this provision, BHP will not be allowed to file any rate application for an increase in base rates which would go into effect prior to January 1, 2017.

19. The Commission finds that the agreements, adjustments, and rates proposed in the Amended Stipulation, considered together with the rate case moratorium, are just and reasonable, and the Amended Stipulation is approved by the Commission.

SDSTA Settlement Agreement

20. The Amended Stipulation in Section III, ¶12 accepts and recommends Commission approval of the SDSTA Settlement Agreement and the Third Amendment incorporated therein. The Amended Stipulation and Third Amendment are contracts with deviations, which are agreements between a public utility and one or more customers that provide for the provision of service under rates, terms, and/or conditions that deviate from the utility's rates, terms, and conditions specified in the utility's tariffs filed with, and approved by, the Commission. Contracts with deviations are generally approved for very large loads or other special business development circumstances under the authority of SDCL 49-34A-8.3. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement for SDSTA subject to the following conditions:

> 1. If the contract with deviations is not subsequently approved by the Commission, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be the rates ultimately approved in the rate case for the applicable class of service, with the difference between the interim rates paid by SDSTA and the rates ultimately approved in the rate case for the applicable class of service to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in a refund order of the Commission after final decision in the general rate case; or

2. If the contract with deviations is subsequently approved by the Commission with modification of the settlement rates to be paid by SDSTA, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be such contract with deviation rates as are ultimately approved by the Commission, with the difference between the conditionally approved interim rates and the contract with deviation rates ultimately approved by the Commission to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in the refund provisions of the Commission's order approving the contract with deviations with modified rates or, if refund is not ordered in such order, in the refund order of the Commission at the time of the general rate decision.

3. This approval does not pre-determine a Commission decision in the current or future rate case proceedings regarding rate treatment of revenue requirement shortfalls resulting from rates approved as contracts with deviations.

21. The SDSTA Settlement Agreement and Third Amendment were filed as confidential documents, as is generally, if not always, the case with contracts with deviations. The Commission finds that the SDSTA Settlement is just and reasonable and is approved by the Commission.

Black Hills Industrial Intervenors' Contested Issues

22. The issues addressed in Findings of Fact 23 through 55 were contested by BHII in its pre-filed and hearing testimony and/or its legal arguments at hearing, in its post-hearing brief, and in argument before the Commission at the Commission's decision hearing on March 2, 2015. Each of these issues is addressed separately below in the above-referenced Findings of Fact.

Allowable Test Year Adjustments under ARSD 20:10:13:44 and Applicable Statutes

23. A number of BHII's contested issues with the Settlement Stipulation and Amended Settlement Stipulation are primarily based on statutory interpretation and to such extent are issues of law, and the details of the Commission's legal rulings on such issues are set forth below in this decision's Conclusions of Law. The primary issue raised by BHII concerns the scope of what may be presented by an applicant for a rate increase within the twenty-four month cost of service adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application. ARSD 20:10:13:44 is set forth in Conclusion of Law 8.

24. In this case, the date 24 months after the end of the test year is September 30, 2015. TR 269.

25. BHII argues that ARSD 20:10:13:44 only allows the consideration of post-test year adjustments which were known and measurable at the time the rate increase application was filed. This position is based upon BHII's interpretation of the phrase "which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing." Ex BHII 1, p. 8.

26. Staff expert witness Peterson testified that during the four plus decades that he has worked with Staff on rate cases, the consistent interpretation of ARSD 20:10:13:44, read together with SDCL 49-34A-19, has been that because a historic test year is used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known expenses during the test year and also adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of its review of the hundreds of responses to discovery requests and filings in the case. TR 279. This has been Staff's consistent policy and is therefore what is reflected in the Settlement Stipulation. It is also Staff's responsibility to closely examine the evidence that such changes are known and measurable expenses. This is the standard that Staff has relied on for years, and the Commission has approved numerous rate case settlements based on that standard. TR 275-276.

27. As is set forth in Conclusions of Law 8 through 10, the Commission concluded that adjustments in the Amended Settlement Stipulation are within the allowable adjustment periods set forth in SDCL 49-34A-19 and ARSD 20:10:13:44. The Commission accordingly finds that substantial and sufficient evidence was produced, introduced, and received in evidence in this proceeding to demonstrate that the rates agreed to in the Amended Settlement Agreement are just and reasonable and will adequately meet BHP's need for revenues sufficient to enable it to meet its current cost of furnishing adequate, efficient, economical, and reasonable service.

Inclusion of Revenue Changes for Period Covered by Post-Test Year Adjustments

28. BHII argues that all post-test year adjustments must be accompanied by changes in revenue during the same period. Ex BHII 1, p. 8.

29. Staff's witness Peterson testified that post-test year adjustments that are revenue producing or income producing must reflect either the additional revenue or the additional income that results from that change in operation before they may be recognized as a known and measurable adjustment. BHP points out that those types of changes are not included in the Settlement Stipulation and Amended Stipulation between BHP and Staff. TR 273; Ex BHP 70, p. 4.

30. Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers), a corresponding revenue adjustment must also be recognized. It is for this reason that the Amended Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Amended Stipulation. Therefore, the Amended Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. Ex Staff 1, p. 9.

31. Staff's analysis has been that if ARSD 20:10:13:44 intended that all revenues, not just those associated with plant additions, are intended or are supposed to be recognized within the 24-month post-test year period, the rule would require a forecast test year. The Commission has never recognized that to be the intent of the rule, nor has the Commission ever adopted or accepted a forecast test year in an electric utility rate increase filing. Therefore, the

only logical conclusion is that the revenue effect of specific post-test year changes has to be acknowledged or recognized in an adjustment before the adjustment itself can be reflected in the revenue requirement. That is the standard that Staff has relied on since the inception of the rule. TR 275-276.

32. In his pre-hearing testimony, BHII's witness Kollen testified that the Commission should limit any post-test year adjustment to the twelve month period immediately following the historical test year ended September 30, 2013. Ex BHII 1, p. 7. This opinion was also asserted by BHII's witness Baron. TR 252. The Commission finds that this would contravene the express language of ARSD 20:10:13:44 and that the Commission's discretion under SDCL 49-34A-19 has historically employed the full two-year adjustment period set forth in the statute. The Commission concludes that the appropriate test year adjustment period is 24 months.

FutureTrack and Associated O&M Costs

33. In its Application, BHP proposed to increase its expenses for its FutureTrack Workforce Development program. The primary purpose of this program was to recruit talent within critical areas to complete the advanced training necessary to fill highly skilled positions upon the retirement of existing employees. Ex BHP 19, p. 6. The Settlement Stipulation and Amended Stipulation both limit the inclusion of such costs to positions actually hired at the time of settlement negotiations without deferral of subsequently hired employee expenses, and did not include recovery for FutureTrack program additional hirings in the future. Ex Staff 1, p. 10; Staff Memorandum, p. 9. BHII's expert witness Kollen expressed the opinion that no recovery should be allowed at all for FutureTrack hirings because they were not known and measurable at the time the Application was filed. Ex BHII 1, pp. 25-30. The Commission finds that BHII's objection is not warranted.

Employee Additions and Eliminations

34. BHII objected to BHP's request for an adjustment to fund employee additions to those employee positions included in the test year. TR 182-183; Ex BHII 1, pp. 30-33. The Amended Stipulation limits recovery for employee additions to those actually hired and in service as of the date of the Settlement Stipulation. Ex Staff 1, p. 10. As with the previous FutureTrack issue, BHII's primary issues were that such additional hirings were not known and measurable as of the date the Application was filed and were speculative on a forward looking basis. The Amended Stipulation's limitation of this adjustment to actual hirings renders the future hiring issue moot. As to the post-test year filing issue, for the reasons set forth in Findings of Fact 23 through 27 and Conclusions of Law 6 through 10, the Commission finds that BHII's objection is not warranted.

NOL ADIT

35. BHII argued and presented both pre-filed and evidentiary hearing expert witness testimony that the Amended Stipulation's proposed inclusion of a tax-related net operating loss (NOL) accumulated deferred income taxes (ADIT) adjustment to the revenue requirement was inappropriate. Ex BHII 1, pp. 10-15; TR 178 et seq. BHP's expert witness Hollibaugh presented both pre-filed and evidentiary hearing testimony regarding the history leading to, the current status of, and the justification for continued maintenance of BHP's NOL ADIT. TR 148 et seq.; Ex BHP 73. Staff's expert witness Peterson testified that "Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements." Ex Staff 1, p. 11. Based on its consideration of the testimony and

supporting documentary evidence presented by both BHP and BHII, the Commission finds that the issue of the NOL ADIT is very complex and that measures to address the underlying tax cost consequences for both BHP and ratepayers can be addressed in more than one justifiable manner.

36. The Commission finds that the NOL ADIT methodology utilized in the past few years and proposed by BHP for approval in this docket has resulted, and will result, in a just and reasonable method of accounting for and reporting BHP's taxable income/loss status and liability/credit, was developed and put into use as a consequence of the unique circumstances presented by the financial challenges and resulting Congressional tax law responses thereto arising from the severe negative economic consequences stemming from the early 2000s and 2008 and ensuing years' recessions, and will result in just and reasonable rate impacts to BHP customers.

Incentive Compensation

37. BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from BHP's affiliates BHUH and BHSC. Ex BHII 6. In the Amended Stipulation, $666,000 of the Company's test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. Ex Staff 1, p. 17. The Amended Stipulation did not change and includes this provision.

38. BHP provided evidence that employee incentive compensation plans are widely employed by utilities throughout the country and that it is necessary for BHP to provide employee incentive opportunities that are competitive with other companies in the industry. Another goal of the program is to focus employees on important objectives to improve the performance of utility operations by focusing on improvements to operational excellence, safety, reliability, and customer satisfaction. TR , 300; Ex BHP 22, pp. 8, 10.

39. BHII's expert witness Kollen offered opinion evidence that in addition to the amount excluded in the Settlement Stipulation, $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses should be excluded because these additional amounts represent incentive awards that are similar in nature to those excluded in the Settlement Stipulation. BHII witness Kollen also offered the opinion that by embedding such incentives in rates, BHP itself is not incentivized to manage toward operational performance. TR 184; Ex BHII 1, pp. 35-37; Ex BHII 6, p. 2.

40. In settlement discussions, Staff raised issues with the incentive compensation plan and the payments made under the plan. Staff's expert witness Peterson testified he did not necessarily disagree with Mr. Kollen's characterization of the incentive awards and in fact, had initially pursued the same issues on behalf of the Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue and agreed to exclude the $666,000 related specifically to financial performance, recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, Mr. Peterson supported the exclusion that is contained in the Settlement Stipulation and recommended that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. TR 285-287; Ex Staff 1, pp. 17-18. The Commission finds that the incentive compensation plan included in the Amended Stipulation does not render the Amended Stipulation unjust and unreasonable.

Pension Expense Normalization

41. As documented in the evidence presented in the case , BHP's pension expense varies significantly year-by-year. Ex Staff 1, p. 16. For example, the Company's test year pension expense was $2,844,759. For 2014, however, the expense dipped down to $976,122. To remedy the problem caused by the fluctuating expense for ratemaking purposes, BHP proposed, and the Staff accepted for settlement purposes, a normalization adjustment based on the average annual expense during the five-year period 2010-2014. These years included a year in which the pension expense was high at $3.25 million (2012) and a year in which the expense was low -- $976,122 (2014). The five-year average expense used for rate setting purposes was $2,336,305. As pointed out in Staff witness Peterson's testimony at hearing, the five-year average that was agreed upon by BHP and the Staff represented over a $500,000 reduction in the test year expense. TR 282.

42. BHII objected to the treatment of the pension expense in the Stipulation characterizing it as "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. Rather, BHII witness Mr. Kollen recommended that BHP's 2014 pension expense be recognized for ratemaking purposes. Ex BHII 1, pp. 33-34.

43. The Commission finds that it is BHII's position, not that of BHP and the Staff, which is opportunistic in this instance with respect to the pension expense. BHII's recommendation would set rates based on the lowest pension expense experienced in the last five years. BHII's recommendation is particularly egregious in this instance given that BHP's witness Thurber testified that the Company's most recent estimate of its 2015 pension expense is $2,056,581 – which is considerably higher than its 2014 expense that Mr. Kollen recommends and similar to the five-year average reflected in the Settlement Agreement. Ex BHP 70, pp. 22-23. The Commission also finds that the normalization treatment of a widely varying expense is consistent with sound regulatory principles and that the Commission has routinely relied on the normalization treatment in prior cases before the Commission, e.g. storm damage expense and uncollectible expenses. The facts and circumstances surrounding the pension expense make it appropriate to apply normalization treatment in this instance. Finally, the Commission further finds that Mr. Kollen's recommended adjustment is internally inconsistent with BHII's position regarding post-test year adjustments in that BHII's witness did not include a revenue adjustment to correspond to its proposed expense adjustment even though BHII incorrectly contends that a revenue adjustment is required for each post-test year adjustment.

Retired Steam Plants Decommissioning Expense

44. In 2014, BHP began to decommission its Neil Simpson 1, Ben French, and Osage coal-fired power plants. The Company expects the decommissioning to be completed by September 2015. BHP proposed to amortize the estimated costs associated with the retirement and decommissioning activities over five years and to include the unamortized balance in rate base. The Settlement Stipulation removes all of the contingency allowances that were included in BHP's original cost estimate. The Settlement Stipulation also revises the amount included for obsolete inventories and reflects a ten-year rather than a five-year amortization period for final retirement and decommissioning costs.

45. BHII objects to the treatment of final retirement and decommission costs associated with these three steam generating stations because it contends "[t]he Company had not yet incurred most of the decommissioning costs that it seeks to include in rate base as of October 1, 2014, twelve months after the end of the historic test year." Ex BHII 1, p. 16.

46. As discussed elsewhere in this Order, the Commission finds no legitimate basis for Mr. Kollen's artificial twelve-month post-test year cut-off. ARSD 20:10:13:44 clearly allows that the Commission look up to 24-months post-test year when evaluating expense adjustments such as this. Therefore, the Commission rejects BHII's recommendation and adopts as just and reasonable the adjusted ten-year amortization expense reflected in the Settlement Stipulation.

Affiliate Allocations

47. The Amended Stipulation includes actual billings by BHP's affiliates – Black Hills Corp. and Black Hills Utility Holdings – to the Company for the twelve months ended August 31, 2014. Thus, the Settlement Stipulation reflects known costs experienced by BHP well within the twenty-four month post-test year period provided for in ARSD 20:10:13:44.

48. BHII objects to any increase in affiliate charges. BHII witness Mr. Kollen contends that there is no justification for the increases in affiliate charges and, further, that the magnitude of the increase is unreasonable on its face. Therefore, Mr. Kollen recommended that the post-test year expense be excluded from BHP's revenue requirement. Ex BHII 1, pp. 37-40.

49. The Commission finds that the affiliate expenses included in the Amended Stipulation are, in fact, the actual expenses that were billed to BHP by its affiliates – Black Hills Corp. and Black Hills Utilities Holdings. Therefore, the affiliate expense adjustments reflected in the Amended Stipulation are known and measurable and just and reasonable for inclusion in BHP's revenue requirement. BHII's contention of these costs being unreasonable on their face is without merit and is hereby rejected.

Steam and Other Production Plant Net Salvage

50. The proposed adjustment to net negative salvage reflects an estimated negative increase to the net of estimated salvage income and cost of removal, or an increase in the shortfall from projected salvage income less than the projected cost of removal. BHII Witness Kollen listed several reasons why he rejected BHP's proposed adjustment as well as the revised Settlement adjustment as set forth in Finding 51.

51. First, the basis for the calculation of the terminal net salvage is flawed and unreliable, resulting in an excessive net negative salvage cost and percentage. Second, this may represent an undisclosed proposal to change the Commission's policy for decommissioning cost recovery from recovery *after* the retirement of the plants (as is the case in this proceeding for the three retired coal-fired plants) to recovery *before* the future retirement of the plants. Third, the increase in net negative salvage is not necessary at this time. The Commission is not required to provide recovery of unknown future costs in present rates. The Commission's current policy appears to be to determine the appropriate manner of decommissioning (and associated costs) *after* plants are retired. This policy is prudent for ratepayers and still ensures that the Company recovers its costs. Ex BHII 1, pp. 47-48.

52. Staff Witness Peterson disagreed, stating that "however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable

costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired." Ex Staff 1, p. 20. The Commission finds that the Amended Stipulation reasonably addresses the net salvage cost issue.

LIDAR

53. As with BHP's decommissioning costs, BHP's LIDAR costs are governed and capped by a fixed rate contract. In the opinion of Staff witness Peterson, these costs are sufficiently known and measurable to be appropriately recognized in rates. The five-year amortization period reflected in the Amended Stipulation was determined to be appropriate because five years is the expected frequency for LIDAR surveying activities. It would be inappropriate to employ a ten-year amortization period as BHII witness Kollen recommends because to do so would unjustifiably burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization matches with the planned survey interval and is therefore more appropriate for these costs. Ex Staff 1, p. 15.

Class Cost of Service Study

54. Because BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. Ex. Staff 1, p. 21.

55. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation, and through Mr. Baron's testimony, BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. Ex Staff 1, pp. 21-22.

Refund of Overcharges

56. Interim rates were implemented on October 1, 2014. Approval of the Amended Settlement Stipulation will authorize a rate increase less than the interim rate level. BHP will refund to customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014, through the effective date of new rates, plus interest. Ex JT 2, p. 5.

57. Refunds with carrying charges of seven percent (7%) annual interest will occur in May 2015, in accordance with BHP's proposed Interim Refund Plan. March 2nd transcript, pp. 29-30.

Tariff Sheets

58. The revised tariff sheets proposed by BHP are as follows:

South Dakota Electric Rate Book

Section No. 1

Twenty-fifth Revised Sheet No. 3	Replaces Twenty-fourth Revised Sheet No. 3

Section No. 3

Fifteenth Revised Sheet No. 1	Replaces Fourteenth Revised Sheet No. 1
Thirteenth Revised Sheet No. 2	Replaces Twelfth Revised Sheet No. 2
Fifteenth Revised Sheet No. 3	Replaces Fourteenth Revised Sheet No. 3
Thirteenth Revised Sheet No. 4	Replaces Twelfth Revised Sheet No. 4
Fifteenth Revised Sheet No. 7	Replaces Fourteenth Revised Sheet No. 7
Fourteenth Revised Sheet No. 8	Replaces Thirteenth Revised Sheet No. 8
Fifteenth Revised Sheet No. 9	Replaces Fourteenth Revised Sheet No. 9
Thirteenth Revised Sheet No. 10	Replaces Twelfth Revised Sheet No. 10
Fifteenth Revised Sheet No. 11	Replaces Fourteenth Revised Sheet No. 11
Fourteenth Revised Sheet No. 12	Replaces Thirteenth Revised Sheet No. 12
Fourteenth Revised Sheet No. 13	Replaces Thirteenth Revised Sheet No. 13
Fifteenth Revised Sheet No. 14	Replaces Fourteenth Revised Sheet No. 14
Thirteenth Revised Sheet No. 15	Replaces Twelfth Revised Sheet No. 15
Seventeenth Revised Sheet No. 16	Replaces Sixteenth Revised Sheet No. 16
Eighteenth Revised Sheet No. 17	Replaces Seventeenth Revised Sheet No. 17
Fourteenth Revised Sheet No. 18	Replaces Thirteenth Revised Sheet No. 18
Fifteenth Revised Sheet No. 19	Replaces Fourteenth Revised Sheet No. 19
Fourteenth Revised Sheet No. 20	Replaces Thirteenth Revised Sheet No. 20
Sixteenth Revised Sheet No. 22	Replaces Fifteenth Revised Sheet No. 22
Fourteenth Revised Sheet No. 23	Replaces Thirteenth Revised Sheet No. 23
Fifteenth Revised Sheet No. 24	Replaces Fourteenth Revised Sheet No. 24
Thirteenth Revised Sheet No. 25	Replaces Twelfth Revised Sheet No. 25
Fifteenth Revised Sheet No. 26	Replaces Fourteenth Revised Sheet No. 26
Thirteenth Revised Sheet No. 27	Replaces Twelfth Revised Sheet No. 27
Ninth Revised Sheet No. 31	Replaces Eighth Revised Sheet No. 31
Eighth Revised Sheet No. 32	Replaces Seventh Revised Sheet No. 32
Original Sheet No. 32A	
Sixth Revised Sheet No. 33	Replaces Fifth Revised Sheet No. 33
Fifth Revised Sheet No. 34	Replaces Fourth Revised Sheet No. 34
Fourth Revised Sheet No. 35	Replaces Third Revised Sheet No. 35
Fifth Revised Sheet No. 36	Replaces Fourth Revised Sheet No. 36
Fourth Revised Sheet No. 37	Replaces Third Revised Sheet No. 37
Third Revised Sheet No. 38	Replaces Second Revised Sheet No. 38

Section 3A

Ninth Revised Sheet No. 1	Replaces Eighth Revised Sheet No. 1
Eighth Revised Sheet No. 2	Replaces Seventh Revised Sheet No. 2
Fifth Revised Sheet No. 3	Replaces Fourth Revised Sheet No. 3
Eighth Revised Sheet No. 4	Replaces Seventh Revised Sheet No. 4

Sixth Revised Sheet No. 5	Replaces Fifth Revised Sheet No. 5
Tenth Revised Sheet No. 6	Replaces Ninth Revised Sheet No. 6
Eighth Revised Sheet No. 7	Replaces Seventh Revised Sheet No. 7
Eighth Revised Sheet No. 8	Replaces Seventh Revised Sheet No. 8
Sixth Revised Sheet No. 9	Replaces Fifth Revised Sheet No. 9
Sixth Revised Sheet No. 10	Replaces Fifth Revised Sheet No. 10
Eighth Revised Sheet No. 11	Replaces Seventh Revised Sheet No. 11
Seventh Revised Sheet No. 12	Replaces Sixth Revised Sheet No. 12
Ninth Revised Sheet No. 13	Replaces Eighth Revised Sheet No. 13
Sixth Revised Sheet No. 14	Replaces Fifth Revised Sheet No. 14
Sixth Revised Sheet No. 15	Replaces Fifth Revised Sheet No. 15
Seventh Revised Sheet No. 16	Replaces Sixth Revised Sheet No. 16
Third Revised Sheet No. 17	Replaces Second Revised Sheet No. 17
Sixth Revised Sheet No. 18	Replaces Fifth Revised Sheet No. 18
Fourth Revised Sheet No. 19	Replaces Third Revised Sheet No. 19
Third Revised Sheet No. 20	Replaces Second Revised Sheet No. 20
Section 3B	
Sixth Revised Sheet No. 1	Replaces Fifth Revised Sheet No. 1
Fifth Revised Sheet No. 2	Replaces Fourth Revised Sheet No. 2
Fifth Revised Sheet No. 3	Replaces Fourth Revised Sheet No. 3
Fifth Revised Sheet No. 4	Replaces Fourth Revised Sheet No. 4
Sixth Revised Sheet No. 5	Replaces Fifth Revised Sheet No. 5
Sixth Revised Sheet No. 8	Replaces Fifth Revised Sheet No. 8
Fifth Revised Sheet No. 9	Replaces Fourth Revised Sheet No. 9
Fifth Revised Sheet No. 10	Replaces Fourth Revised Sheet No. 10
Section 3C	
Twelfth Revised Sheet No. 5	Replaces Eleventh Revised Sheet No. 5
Fourteenth Revised Sheet No. 11	Replaces Thirteenth Revised Sheet No. 11
Sixth Revised Sheet No. 12	Replaces Fifth Revised Sheet No. 12
First Revised Sheet No. 13	Replaces Original Sheet No. 13
Second Revised Sheet No. 14	Replaces First Revised Sheet No. 14
Second Revised Sheet No. 15	Replaces First Revised Sheet No. 15
Section 4	
Fourth Revised Sheet No. 4	Replaces Third Revised Sheet No. 4
Eighth Revised Sheet No. 5	Replaces Seventh Revised Sheet No. 5
Sixth Revised Sheet No. 6	Replaces Fifth Revised Sheet No. 6
Section 5	
Third Revised Sheet No. 4	Replaces Second Revised Sheet No. 4
Fifth Revised Sheet No. 21	Replaces Fourth Revised Sheet No. 21
Fourth Revised Sheet No. 22	Replaces Third Revised Sheet No. 22
Section 6	
Third Revised Sheet No. 22	Replaces Second Revised Sheet No. 22

General

59. As stated in the Staff Memorandum, with respect to a Settlement Stipulation, petty criticisms can be levied against individual elements of the Settlement Stipulation. Because it is an agreed resolution of the case, however, a settlement stipulation is more appropriately judged on the basis of its overall resolution of the case because it involves trade-offs between the parties to it. The Commission believes that this is the appropriate way of assessing the justness and reasonableness of this Amended Stipulation as well. BHII focuses on the minute details of the Settlement Stipulation in isolation.

60. Staff witness Peterson testified that Staff believes that the end result of the Settlement Stipulation results in just and reasonable rates, and it reasonably reflects the cost that BHP will incur going forward. There were a number of issues which the Staff and the company disagreed on. The Staff's resolution of those issues is stated in the Staff Memorandum, but BHP had its own basis for settling certain issues which were either advantageous or adverse to the company. Staff does not see the company's analysis of that. But the end result, Staff believes, was just and reasonable rates and reasonably reflects the cost that the company expects to incur going forward. TR 280.

61. The Commission finds that the rates, terms and conditions in the Amended Stipulation demonstrate a thorough, penetrating, and credible analysis by Staff and its expert witnesses of the data and assumptions underlying the Application and the Amended Settlement Stipulation; balance fairly the interests of BHP and its customers; recover no more than BHP's current revenue requirements, including a reasonable return to its stockholders commensurate with its cost of equity capital; are supported by substantial evidence; and meet the just and reasonable standard set forth in SDCL 49-34A-6, as more specifically delineated in SDCL 49-34A-8, the unreasonable preference or advantage and unreasonable prejudice or disadvantage prohibitory standards of SDCL 49-34A-3, the fair and reasonable return standard of SDCL 49-34A-8, and are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers as provided in SDCL 49-34A-8.4. These settlement rates allow BHP a reasonable opportunity to earn a return that is adequate to enable it to continue providing safe, adequate, and reliable service to its South Dakota retail customers.

62. The Commission finds that neither the SDSTA Settlement Agreement nor the Commission's approval of the SDSTA Settlement Agreement has affected the costs to be recovered from BHP's other customers under the Amended Settlement Stipulation.

63. To the extent that any Conclusion of Law set forth below is more appropriately a finding of fact, that Conclusion of Law is incorporated by reference as a Finding of Fact.

CONCLUSIONS OF LAW

1. The following statutes and rules are applicable to this proceeding and vest the Commission with jurisdiction over this matter: SDCL Chapters 1-26 and 49-34A, including 1-26-20, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.4, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-21, and 49-34A-22, and ARSD Chapters 20:10:01 and 20:10:13.

2. The primary issue raised by BHII concerns the scope of what adjustments may be presented by an applicant for a rate increase within the twenty-four month cost of service

adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application.

3. SDCL 49-34A-6 provides:

Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.

4. SDCL 49-34A-8 provides:

The commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its total current cost of furnishing such service, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

5. SDCL 49-34A-8.4 provides:

The burden is on the public utility to establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers in this state.

6. SDCL 49-34A-19 provides in relevant part:

In determining the revenue requirement the commission shall consider revenue, expenses, cost of capital and any other factors or evidence material and relevant thereto. The commission may take into consideration the reasonable income and expenses that will be forthcoming in a period of twenty-four months in advance of the test year.

7. ARSD 20:10:13:01(11) provides as follows:

"Test period," the test period outlined in § 20:10:13:44, except that if additional material is filed by the utility, a test period is any 12 consecutive months beginning no later than the proposed effective date of the rate application.

8. ARSD 20:10:13:44 provides as follows:

The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period.

9. As set forth in Findings of Fact 24, these provisions have for decades been interpreted together as providing for a historic test year as the cost of service basis period, but also, in part because such cost of service data are used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known and measurable expenses during the test year and adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period for case processing provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of their submission for Staff review of the responses to hundreds of discovery requests and filings in the case. Although the phrase "in advance of" is anomalous when read together with the word "forthcoming," the Commission concludes that the intent of SDCL 49-34A-19 is to permit the consideration of cost of service evidence that becomes known and measurable during the twenty-four month period following the end of the test year, that such interpretation is not inconsistent with the phrase "at the time of the filing" due to the voluminous "filings" in a rate case over a two year period in most rate cases, and that such interpretation results in the most accurate real-time basis for the utility's rates, thus minimizing the need for an immediate or near term filing by the utility of a follow-on rate case to recover such costs.

10. As to the issue of revenue during the twenty-four month rate case processing period, BHII argues that BHP and Staff neglected to provide and/or consider evidence of BHP's revenue during such period. BHII argues that this violates the matching principle and also runs contrary to SDCL 49-34A-19. BHP and Staff in contrast argue that the matching principle is not violated because the only adjustments accepted by Staff are adjustments that have no revenue generating component to them. The Commission concludes that none of the cost adjustments included in the Amended Settlement Stipulation result in additional revenue for BHP, and, in the context of a settlement stipulation that very significantly reduces the revenue requirement from what was requested by BHP in its Application and supported by its experts in its pre-filed and hearing testimony, such adjustments are just and reasonable.

11. With respect to BHII's argument at the March 2, 2015, decision hearing that BHII was not afforded due process to contest the Amended Settlement Stipulation's correction of the error in the BHUH allocation, the Commission concludes that this substantive amendment to the original Settlement Stipulation occurred precisely as a result of evidence introduced and

considered at the evidentiary hearing and the pre-filed testimony filed prior to the hearing and received in evidence at the hearing. The error in the calculation of the BHUH allocation was pointed out in BHII's expert witness Kollen's pre-filed testimony and acknowledged by BHP witness Thurber and Staff witness Peterson to be accurate in their pre-filed testimony and at hearing. The Commission has already heard the evidence and arguments regarding this amendment to the Settlement Stipulation, and nothing would be gained by another hearing on a matter that has already been heard.

12. No statute or rule precludes the inclusion of employee incentive compensation in the utility's cost of service and revenue requirement. The Commission's decision whether to allow incentive compensation and, if so, subject to what limitations are judgment calls concerning what meets the just and reasonable standard.

It is therefore

ORDERED, that the Amended Settlement Stipulation between Black Hills Power, Inc. and Staff is approved as the substance of the decision of the Commission in this docket with an effective date of April 1, 2015, and with refunds of interim rate billings in excess of the approved rates plus carrying charges of seven percent (7%) annual interest to occur in May, 2015, in accordance with BHP's proposed Interim Refund Plan. It is further

ORDERED, that the Settlement Agreement between Black Hills Power, Inc. and the South Dakota Science and Technology Authority and the Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority are approved and refunds to SDSTA shall not therefore be necessary.

NOTICE OF ENTRY AND OF RIGHT TO APPEAL

PLEASE TAKE NOTICE that this Final Decision and Order; Notice of Entry was duly issued and entered on the 17th day of April, 2015. Pursuant to SDCL 1-26-32, this Final Decision and Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties. Pursuant to ARSD 20:10:01:30.01, an application for a rehearing or reconsideration may be made by filing a written petition with the Commission within 30 days after the date of issuance of this Final Decision and Order; Notice of Entry. Pursuant to SDCL 1-26-31, the parties have the right to appeal this Final Decision and Order to the appropriate Circuit Court by serving notice of appeal of this decision to the circuit court within thirty (30) days after the date of service of this Notice of Decision.

Dated at Pierre, South Dakota, this 17th day of April, 2015.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically ~~or~~/by mail.

By: [signature]

Date: 4/17/15

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

[signature]

CHRIS NELSON, Chairman

[signature]

KRISTIE FIEGEN, Commissioner

[signature]

GARY HANSON, Commissioner

Appendix A – Confidential

STATE OF SOUTH DAKOTA COUNTY OF HUGHES	)) :SS)	IN CIRCUIT COURT SIXTH JUDICIAL CIRCUIT
IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))))	CIV NO. 15-146 ORDER

WHEREAS, the Court having issued its Memorandum Decision dated January 8, 2016, and having incorporated it here by reference, now, therefore, it shall be and hereby is

ORDERED that the Public Utility Commission's Final Decision to approve the Amended Settlement Stipulation between Black Hills Powers, Inc. and Staff to increase electric rates is AFFIRMED.

Dated this 8th day of January, 2016.

BY THE COURT:

Mark Barnett

Honorable Mark Barnett
Sixth Circuit Court Judge

ATTEST:

Clerk of Courts

(SEAL)

CIRCUIT COURT OF SOUTH DAKOTA
SIXTH JUDICIAL CIRCUIT

HUGHES COUNTY COURTHOUSE
P.O. BOX 1238
PIERRE, SOUTH DAKOTA 57501-1238

MARK BARNETT
CIRCUIT COURT JUDGE
Phone: (605) 773-4014
Fax: (605) 773-6492
Mark.Barnett@ujs.state.sd.us

LORI J. GRODE
COURT REPORTER
Phone: (605) 773-8227
Lori.Grode@ujs.state.sd.us

KATIE J. HRUSKA
SIXTH CIRCUIT LAW CLERK
Katie.Hruska@ujs.state.sd.us

January 8, 2016

Mark Moreno
Moreno, Lee & Bachand, P.C.
Pierre, SD 57501
mmoreno@pirlaw.com

Andrew Moratzka
Stoel Rives LLP
Minneapolis, MN 55402
andrew.mortatzka@stoel.com

Karen Cremer
S.D. Public Utilities Commission
Pierre, SD 57501
karen.cremer@state.sd.us

Lee Magnuson
Lindquist & Vennum, LLP
Sioux Falls, SD 57103
lmagnuson@lindquist.com

RE: Hughes County Civ. No. 15-146: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates

MEMORANDUM DECISION

Black Hills Industrial Intervenors appeal the Public Utility Commission's Final Decision to approve the Amended Settlement Stipulation with respect to Black Hills Power's application for authority to increase electric rates. This Court affirms.

BACKGROUND

On March 31, 2014, Black Hills Power, Inc. ("BHP") filed an Application for Authority to Increase Electric Rates with the South Dakota Public Utility Commission ("Commission"). The Application included supporting exhibits. The requested increase in electric service rates was approximately $14.6 million annually or about 9.27% based on BHP's test year ending September 30, 2013. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The change would affect approximately 65,500 customers in the service territory. As required, the Application included a cost of service analysis.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively Black Hills Industrial Intervenors or "BHII") filed a Motion to Intervene. Dakota Rural Action ("DRA") also filed a Motion to Intervene. The Commission granted Intervention on June 26, 2014.

The Staff of the Commission ("Staff") served over 330 discovery requests and BHII served over 60 discovery requests, to which BHP responded. The parties began negotiations to settle and stipulate to the rates, terms, and conditions for the increase of electric rates. On December 9, 2014, BHP and Staff filed a Joint Motion for Approval of Settlement Stipulation, the Settlement Stipulation, and Exhibits. BHII and DRA were not parties to the settlement. Notice of Hearing set this matter for Commission hearing on January 27-29, 2015. The parties, including BHII, pre-filed testimony of several witnesses.

The hearing was held on January 27 and 28, 2015. After the hearing, the Commission set the matter for voting on March 2, 2015. On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation reflecting two changes in the factual basis supporting the revenue requirement, due to new information contained in pre-filed testimony and evidence introduced at the hearing. (The Amended Stipulation did not change the agreed upon overall revenue deficiency). Further post-hearing briefs were accepted. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Settlement Stipulation.

During an open meeting deliberation on March 2, 2015, Commissioners asked questions of the parties and made their decision. The Commissioners voted unanimously to grant the Joint Motion and approved the terms and conditions stipulated to in the Amended Settlement Stipulation, as the decision of the Commission on the rate increase requested by BHP, effective on April 1, 2015. The Commission issued its Final Decision on April 17, 2015. "The Commission [found] that the agreements, adjustments, and rates proposed in the Amended Stipulation, considered together with the rate case moratorium, are just and reasonable, and the Amended Stipulation is approved by the Commission." FOF 19.

BHII filed a Petition for Rehearing and Reconsideration but the Commission denied the motion on May 29, 2015. BHII filed its Notice of Appeal on June 26, 2015.

QUESTIONS PRESENTED

I. Whether the Commission erred in allowing any adjustments to the cost of service analysis under ARSD 20:10:13:44 when the proposed adjustments were made *after* the initial filing of the Application *but* which had become "known and measurable" at the time of *filing the adjustment*, and the adjusted costs would be effective within 24 months after the end of the test year?

II. Whether the Commission erred by using 2010–2014 in its five-year normalization calculation for pension expenses instead of 2011–2015?

III. Whether the Commission erred when it included $888,000 of BHP's incentive compensation package expense, in its cost of service analysis?

STANDARD OF REVIEW

This court's review of a decision from an administrative agency is governed by SDCL 1-26-36.

> The court shall give great weight to the findings made and inferences drawn by an agency on questions of fact. The court may affirm the decision of the agency or remand the case for further proceedings. The court may reverse or modify the decision if substantial rights of the appellant have been prejudiced because the administrative findings, inferences, conclusions, or decisions are:
>
> (1) In violation of constitutional or statutory provisions;
>
> (2) In excess of the statutory authority of the agency;

> (3) Made upon unlawful procedure;
>
> (4) Affected by other error of law;
>
> (5) Clearly erroneous in light of the entire evidence in the record; or
>
> (6) Arbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion.
>
> A court shall enter its own findings of fact and conclusions of law or may affirm the findings and conclusions entered by the agency as part of its judgment.

SDCL 1-26-36.

"[Q]uestions of law, including statutory interpretation, are reviewed de novo." *Pesall v. Montana Dakota Util. Co., et al.*, 2015 S.D. 81, ¶ 6, __ N.W.2d __. "The final construction of an administrative rule is a question of law fully reviewable by this Court on appeal." *State v. Guerra*, 2009 S.D. 74, ¶ 32, 772 N.W.2d 907, 916. "Whether the Department correctly applied its rules presents a question of law[.]" *Media One*, 1997 S.D. 17, ¶ 11, 559 N.W.2d at 878. "However, 'an agency is usually given a reasonable range of informed discretion in the interpretation and application of its own rules when the language subject to construction is technical in nature or ambiguous, or *when the agency interpretation is one of long standing*.'" *Krsnak v. S. Dakota Dep't of Env't & Natural Res.*, 2012 S.D. 89, ¶ 16, 824 N.W.2d 429, 436 (quoting *Guerra*, 2009 S.D. 74, ¶ 32, 772 N.W.2d at 916) (emphasis added).

The Commission's "findings of fact are reviewed under the clearly erroneous standard . . . [a] reviewing court must consider the evidence in its totality and set the [Commission's] findings aside if the court is definitely and firmly convinced a mistake has been made." *In re Otter Tail Power Co. ex rel. Big Stone II*, 2008 S.D. 5, ¶ 26, 744 N.W.2d 594, 602 (citing *Sopko v. C & R Transfer Co., Inc.,* 1998 SD 8, ¶ 7, 575 N.W.2d 225, 228-29)).

ANALYSIS

Generally, BHII's argument is that the Commission should have rejected the Amended Settlement Stipulation because certain adjustments were either not "fully supported" or were not "known with reasonable certainty and measurable with reasonable accuracy" at the time BHP filed its *initial* Application, in claimed violation of ARSD 20:10:13:44. In other words, they argue that once the initial Application is filed, no "adjustments" can be made at all. The Commission's and BHP's (collectively, the "Appellees") argument is that the Commission's long standing interpretation of ARSD 20:10:13:44 regarding adjustments was correct and should be given a reasonable range of informed discretion; the Commission's decision was not clear error; and the Amended Settlement Stipulation provided for an increase of rates that was "just and reasonable."

I.

Whether the Commission erred in allowing any adjustments to the cost of service analysis under ARSD 20:10:13:44 when the proposed adjustments were made *after* the initial filing of the Application *but* which had become "known and measurable" at the time of *filing the adjustment*, and the adjusted costs would be effective within 24 months after the end of the test year?

The first and foremost question before this Court is whether adjustments can be made after a public utility submits its *initial* application for a rate increase. This issue pivots on the interpretation of ARSD 20:10:13:44.

Standard of Review

The parties disagree on the applicable standard of review. BHII asserts that the interpretation of rules and statutes are questions of law, which allow this Court to fully review the decisions of the Commission. BHP agrees that questions of law are fully reviewable but claims that the Commission's conclusions of law on regulatory interpretation are entitled to great weight, and that the court must give a "reasonable range of informed discretion [for interpreting rules]." *BHP Br.* at 5. The Commission asserts that it is an agency with expertise and that courts must give appropriate "deference to PUC's expertise and special knowledge in the field of electric utilities." *Pesall v. Montana Dakota Util. Co., et al.*, 2015 S.D. 81, ¶ 8, __ N.W.2d __; *see In re W. River Elec. Ass'n, Inc.*, 2004 S.D. 11, ¶ 25, 675 N.W.2d 222, 230.

Regarding the interpretation of ARSD 20:10:13:44, this Court does not believe that the rule is ambiguous or in need of interpretation. Even if it were found ambiguous, the Court would give the Commission a reasonable range of informed discretion when interpreting and applying this Rule because the Commission's interpretation is one of long standing.[1]

[1] FOF 26; *Krsnak*, 2012 S.D. 89, ¶ 16, 824 N.W.2d at 436. *See* TR. at 271-79 for a full explanation of Peterson's interpretation that has been "precisely the standard that the Commission Staff has relied on since the inception of this rule." TR. at 276. Staff Witness Peterson testified that "It is my understanding that the Commission's long-standing policy has been to consider post-test year adjustments up to twenty-four months . . . beyond the end of the test year provided they are known with reasonable certainty and measureable with reasonable accuracy. . . . [I]t is my understanding that both the Commission Staff and the Commission have previously interpreted this rule to mean

While ARSD 20:10:13:44 has been interpreted and applied at the Commission level on many occasions, its construction has not been decided in the courts.

Construction

"Administrative regulations are subject to the same rules of construction as are statutes. When regulatory language is clear, certain and unambiguous, our function is confined to declaring its meaning as clearly expressed." *Krsnak*, 2012 S.D. 89, ¶ 16, 824 N.W.2d at 436 (citations omitted).

> The purpose of statutory [and regulatory] construction is to discover the true intention of the law [or rule] which is to be ascertained primarily from the language expressed in the statute [or rule]. The intent of a statute [or rule] is determined from what the legislature said, rather than what the courts think it should have said, and the court must confine itself to the language used. Words and phrases in a statute [or rule] must be given their plain meaning and effect. When the language in a statute [or rule] is clear, certain and unambiguous, there is no reason for construction, and the Court's only function is to declare the meaning of the statute [or rule] as clearly expressed. Since statutes [or rules] must be construed according to their intent, the intent must be determined from the statute [or rule] as a whole, as well as enactments relating to the same subject. But, in construing statutes [or rules] together it is presumed that the legislature did not intend an absurd or unreasonable result.

Hayes v. Rosenbaum Signs & Outdoor Adver., Inc., 2014 S.D. 64, ¶ 28, 853 N.W.2d 878, 885 (quoting *Martinmaas v. Engelmann,* 2000 S.D. 85, ¶ 49, 612 N.W.2d 600, 611).

The first step is to analyze the plain language and effect of the Rule in question to determine if there is ambiguity. ARSD 20:10:13:44 provides the requirements of the cost of service analysis.

> The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual

---

that for any post-test year change in expense or investment that has an incremental revenue component . . . a corresponding revenue adjustment must also be recognized." *Exh. Staff 1* at 8-9.

> experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. . . .

This 12-month period is commonly called the "test year" or "test period". ARSD 20:10:13:01(11).[2] BHP chose its test year ending September 30, 2013. "The purpose of a test year is to establish with a reasonable degree of accuracy the revenue and expenses that a utility will experience during the period when the new rates will be in effect." *In the Matter of the Application of Northwestern Pub. Serv. Co. for a Proposed Increase in Rates for Electric Serv.*, 297 N.W.2d 462, 469 (S.D. 1980). The Rule goes on to provide conditions for submitting adjustments to the test year data.

> . . . Proposed adjustments to book costs shall be shown separately and *shall be fully supported*, including schedules showing their derivation, where appropriate. However, no *adjustments* shall be permitted unless *they* are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy *at the time of the filing* and *which will become effective within 24 months of the last month of the test period* used for this section and unless expected changes in revenue are also shown for the same period.

ARSD 20:10:13:44 (emphasis added).

BHII reads "at the time of the filing" to mean at the time of BHP's *initial* application filing on March 31, 2014. BHII's position is that the Rule only allows adjustments which are known and measurable as of March 31, 2014; thereby arguing any adjustments made to costs after this filing date should have been rejected *even if* the actual cost became known and measurable after the initial filing of the application. Appellees argue that because there are voluminous filings,[3] the phrase refers to the filing *of the adjustment* as long as that adjusted

[2] " 'Test period,' the test period outlined in § 20:10:13:44, except that if additional material is filed by the utility, a test period is any 12 consecutive months beginning no later than the proposed effective date of the rate application."

[3] The administrative record spans more than 7,800 pages, stored in more than three bankers' boxes. *See* Chronological Index. Some of the proposed adjustments became known by responding to over 390 discovery requests from Staff and BHII. FOF 10 (citing *Exh. Staff* 1 at 5; TR. at 263, 268-68).

cost is known and measurable at the time BHP filed the adjustment with supporting materials. The Rule is only "ambiguous when it is capable of being understood by reasonably well-informed persons in either of two or more senses." *State v. Mundy-Geidd*, 2014 S.D. 96, ¶ 7, 857 N.W.2d 880, 884.

Consider again the portion of the rule at issue:

> Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period.

ARSD 20:10:13:44 (emphasis added). The initial application is not the subject of this passage. The cost of service analysis shall be submitted with the initial application,[4] but nowhere in the rule does it refer to the "application." Instead, this Rule is about the content of the cost of service analysis and when adjustments can be proposed and how they can be permitted. The subject of each sentence in this adjustment passage is "adjustments" and all modifiers refer to "adjustments." "It is a general rule of statutory construction that modifying phrases or clauses should be referred to the word, phrase, or clause with which they are grammatically connected." *Farmland Ins. Companies of Des Moines, Iowa v. Heitmann*, 498 N.W.2d 620, 624 (S.D. 1993). The phrase, "at the time of the filing" refers to when the "changes in facilities, operations, or costs" can be made. "Changes in facilities, operations, or costs" (a phrase synonymous with adjustments) refers to the pronoun, "they", which is the antecedent for "adjustments" in the beginning of the sentence. The only reasonable interpretation based on the sentence structure is that adjustments are permitted after the initial application is filed.

"[The court] may not, under the guise of judicial construction, add modifying words to the statute or change its terms." *State v. Moss*, 2008 S.D. 64, ¶ 15, 754 N.W.2d 626, 631. Adopting BHII's interpretation would have this Court adding the words "of the initial application" after "filing." If the Legislature intended that adjustments were cut off at the time of application, it could have used the word "application" instead of "filing". On the contrary, interpreting "filing" to be the filing of the adjustment does not add words when the subject and the dominant

[4] ARSD 20:10:13:43 instructs that "[t]he initial application for a rate increase under this chapter shall include a cost of service study . . ."

purpose of the sentence is "adjustment." The clear intention of the Rule is to allow proposed adjustments to the statement of cost of service, even after filing the initial application, but only if the adjustment is shown separately and is fully supported. Then, the adjustment will only be approved if the two-part test ("known and measurable" and "effective within 24 months" provisions) is met when the adjustment is proposed and filed.

Also, the Court cannot "adopt an interpretation of a [Rule] that renders the [Rule] meaningless when the [agency] obviously passed it for a reason." *Schafer v. Shopko Stores, Inc.*, 2007 S.D. 116, ¶ 7, 741 N.W.2d 758, 761 (citation omitted). To adopt BHII's interpretation that no adjustments can be made after the moment the utility files its application would render the entire passage about adjustments meaningless. The Rule obviously permits adjustments that meet a certain test, even when the adjustment is made after filing the application. If those adjustments could only be made before the application is submitted to the Commission, then those changes would not be "adjustments," they would just be edits to a draft cost of service analysis. Put another way, if the application is final and cannot be changed from the moment it is filed with the Commission, no adjustment would ever be contemplated and that entire passage of the Rule would be useless verbiage. Similarly, if no changes could be made after the initial filing, what need would there be in the rule, to discuss ". . . changes in facilities, operations, or costs"? They would not be changes at all. If anything seems clear in this Rule, it is that the words "adjustments" and "changes" mean that utilities can propose adjustments and changes to the initial application. No interpretation is needed. However, even if the Rule needs interpretation, the Commission still prevails.

Adjustments Ensure Finding a "Just and Reasonable" Rate

The Commission's ultimate mission is stated in SDCL 49-34A-6: "Every rate made, demanded or received by any public utility shall be just and reasonable." SDCL 49-34A-8 explains the criteria the Commission must consider when determining whether a rate is just and reasonable:

> [The Commission] shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its *total current cost of furnishing such service*, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

SDCL 49-34A-8 (emphasis added). Appellees correctly assert that adjustments should be allowed (if they meet the two test provisions) after the initial filing because it will result in the most accurate basis for determining "just and reasonable" utility rates, whether that adjustment to the test year cost is an increase or a decrease. In order to determine if a rate is adequate, efficient, and economical, the Commission needs to know the most *current* actual costs of providing the utility service so the result is just and reasonable for the public and the utility. The Commission's intention for this Rule was to allow adjustments to the test year. If no adjustments were allowed after filing the rate application, then actual costs and changes later known and measurable would have to be ignored, or the utility would have to withdraw its application every time an expense changed.[5]

The Commission's interpretation of ARSD 20:10:13:44 is also harmonious with other related statutes and rules. SDCL 49-34A-19 provides:

> In determining the revenue requirement the commission shall consider revenue, expenses, cost of capital and any other factors or evidence material and relevant thereto. *The commission may take into consideration the reasonable income and expenses* that will be forthcoming in a period of twenty-four months in advance of the test year.

SDCL 49-34A-19.[6] This statute allows the Commission discretion to consider costs that will be effective within 24 months of the end of the test period; likewise under

---

[5] The Court cannot construe a rule to an absurd or unreasonable result. *Hayes v. Rosenbaum Signs & Outdoor Adver., Inc.*, 2014 S.D. 64, ¶ 28, 853 N.W.2d 878, 885. BHII's interpretation would require a utility to withdrawal its entire application and refile if one expense needs to be adjusted after filing the application. Withdrawing the application would waste the utility's resources (the filing fee is $100,000), the Commission's time, and is unreasonable considering the expressed permission to file adjustments. Most importantly, the Rule does not require a utility to withdraw its application when a cost is missed or needs to be adjusted; instead, the Rule expressly allows the cost to be adjusted.

Furthermore, BHII recognizes that their interpretation will cause a new issue in rate cases. Appellant's Br. at 16, fn. 6. If a utility erred by failing to include a known expense in its cost of service before filing its application, then the utility must now prove when it knew about the expense, regardless of the fact that is an actual current cost the company must pay. This would unreasonably add irrelevant, substantive evidence to a rate case where the contested issue should be whether the proposed rate is just and reasonable. By interpreting the Rule as Appellees have, there is no issue about when the utility knew about an expense, and inadvertent omissions do not result in tangential issues.

[6] The Commission recognized the peculiar use of "in advance of" in this statute. It concluded,

> Although the phrase 'in advance of' is anomalous when read together with the word 'forthcoming,' the Commission concludes that the intent of SDCL 49-34A-19 is to permit the consideration of cost of service evidence that becomes known and measurable during the twenty-four month period following the end of the test year, that such interpretation is not inconsistent with the phrase 'at the time of the filing' due to the voluminous 'filings' in a rate case over a two year period in most rate cases, and that such interpretation results in the most accurate real-time basis for the utility's rates[.]

ARSD 20:10:13:44, the Commission permits adjustments if they are effective within the 24 months of the end of the test period. This statute does not prohibit considering reasonable income and expenses, which will be forthcoming, but are not known until after the utility files its initial application. The statute supports the principle of determining a just and reasonable rate by allowing consideration of more than just the test year data.

Staff witness Peterson explained the Commission's long-standing policy of accepting adjustments after the initial filing of the application. Peterson concluded that when read together, ARSD 20:10:13:44 and SDCL 49-34A-19 permit the use of known expenses during the test year and any known changes that occur up to 24 months after the test year and are known "at the time of their submission for Staff review." The Commission agreed with Peterson's interpretation. FOF 26, 27; COL 9. This informed conclusion is consistent with the plain language of the statute and the practical, reasonable interpretation of the Rule.

Accurate and Up-To-Date Costs

BHII argues that their interpretation "helps ensure that the utility's cost of service is as accurate as possible as of the date it files its application." *BHII Br.* at 12. This interpretation would mean the rate analysis is *only* as accurate as of the day the application was filed, yet it may take up to a year to make a decision on a rate case. During that time, things change within the utility.[7] Thus, a correct reading of ARSD 20:10:13:44 accommodates for the length of time (or "administrative lag") and for the fact that costs or revenues legitimately change during the year. Within the next 12 months or more following the initial application, discovery occurs, testimony is heard, and a contested hearing may be held where it may become apparent adjustments are needed to some figures. All the while, the utility continues to conduct business which may result in new costs.[8] It seems the entire purpose of the Rule is to acknowledge and accommodate not only the shifting nature of the information in a dynamic industry, but to make sure the Commission has the very latest information available to it on account of the administrative lag. So, if new data becomes available during the pendency of the case, which could raise or lower a fair rate, the Rule allows the utility to propose the change and the Rule gives guidance to the Commission of the circumstances in which it may accept the adjustment. Allowing for this administrative lag and permitting adjustments to the test year throughout the rate case proceeding

---

COL 9. BHP offers that this statute means "the Commission may consider reasonable expenses that will be forthcoming within 24 months of the last month of the test period (until September 30, 2015), as post-test year adjustments. *BHP Br.* at 10. This reading is consistent with ARSD 20:10:13:44.

[7] Business decisions change. The markets move. Old facilities wear out or new facilities are put online. Data may be overlooked during the initial process, or data can be sharpened.

[8] It takes time to give notice of the application for a rate increase, to serve all the parties, to allow time from intervenors' participation, to perform discovery and make motions, to prepare expert testimony, to participate in settlement negotiations, and to conduct a hearing and vote.

provides the *most accurate* and *up-to-date* cost of service analysis possible. What is more, if the Court applied the interpretation offered by BHII, it would mean that no adjustments would be permitted, even when the adjustment could lower rates for customers, and that cannot be the intent of the Rule.

Specific Adjustments were Fully Supported

BHII highlights three expenses: LiDAR costs,[9] affiliate allocations,[10] and open position expenses,[11] and argues that these initially were only unreliable budget amounts improperly included on the cost of service statement,[12] and likewise should have been rejected because the actual value was not known at the time BHP filed its initial application. BHII cites to *Nw. Pub. Serv. Co.* for the principle that a public utilities commission acts "arbitrarily by using predictions of income and expenses based on test-year data and ignoring available evidence of actual post test-year earnings." *In re Application of Nw. Pub. Serv. Co. for a Proposed Increase in Rates for Electric Serv.*, 297 N.W.2d 462, 469 (S.D. 1980) (citing *W. Ohio Gas Co. v. Pub. Util. Comm'n*, 294 U.S. 79, 55 S. Ct. 324, 79 L. Ed. 773 (1935)[13]). BHP responds that none of the costs in the *Settlement Stipulation* were budget numbers

---

[9] The LiDAR expense was initially submitted as a budget amount because BHP knew it would incur expenses for surveying costs for LiDAR within 24 months but the amount was not known or measurable when it submitted its initial rate application. The Staff of the Commission rejected the budget amount. But then, the actual amount became known and measurable soon thereafter when "the LIDAR surveying work and data acquisition was completed in the fourth quarter of 2014." *BHII Br. Appx.* A-380 (Thurber Rebuttal Testimony 13). Then, BHP filed an adjustment with supporting materials to fully support to the adjustment, which the Staff revised and the Commission accepted. *See* FOF 53. This is exactly what ARSD 20:10:13:44 allows.

[10] The second adjustment was to affiliate allocations. This expense was first submitted as a budget amount and was rejected. *See Orig. Settl. Memo* at 7. But after receiving a detailed summary of its most recent annualized expenses, an adjustment was made to include the actual annual amounts billed to BHP, and the Commission approved it. FOF 49.

[11] A third adjustment was made to payroll and expenses relating to filled positions as of December 2014. In March 2014 when BHP submitted its application, BHP could not have known how many positions would be filled in the future. So, Staff and BHP agreed on a cut-off date as of the December Settlement Stipulation for submitting an adjustment based on a cost that would be known and measurable at that time. FOF at 33, 34. Therefore, the cost of service was adjusted to reflect only the employee additions for actual employees hired because those were known and measurable. The Commission approved this adjustment. *See* FOF 33.

[12] *In re Minnesota Gas Co.*, 1979 WL 461903, at * 4 (S.D.P.U.C. Sept. 26, 1979) (finding that "a projected test year based upon estimates is in total contravention of the rational and sound rate-making principle of utilizing a test year adjusted for known and measurable changes.").

[13] The United States Supreme Court reasoned,

> We think the adoption of a single year as an exclusive test or standard imposed upon the company an arbitrary restriction in contravention of the Fourteenth Amendment and of 'the rudiments of fair play' made necessary thereby. The earnings of the later years were exhibited in the record and told their own tale as to the possibilities of profit. To shut one's eyes to them altogether, to exclude them from the reckoning, is as much arbitrary action as to build a schedule upon guesswork with evidence available.

Id. at 469.

so there was no error approving the Stipulation. Instead, in the initial application, BHP included some budget numbers but all were either struck later or adjusted if the actual value became known and measurable. Staff agreed and rejected those expenses as budgets at first, but allowed adjustments to these three expenses when the actual amount became known.

BHII claims that only one case has allowed a utility to adjust the estimate of costs to account for actual post test-year expenses after filing the initial application. BHII attempts to distinguish that case, *Nw. Pub. Serv. Co.*, 297 N.W.2d 462 (S.D. 1980), because it did not interpret ARSD 20:10:13:44. In that case, the Big Stone Power Plant went on line during the test year and was the motivating factor for requesting a rate increase. Without historical data for the new power plant, the cost was based on a prediction calculated in a letter by a co-owner of the plant, who made certain assumptions for production. By the time the Commission heard the rate increase case, "the plant had been in operation for nearly a year. [The] Company presented evidence of its actual experience with the plant during that year which showed that the power production prediction contained in the Johnson letter was highly overestimated." *Nw. Pub. Serv. Co.*, 297 N.W.2d at 469. The court found that the Commission erred by ignoring the actual experience data and failing to adjust the cost, which was based on speculative data.

Whether or not this case factually matches the instant case, the reasoning is sound and useful. BHP knew it would have actual expenses for LiDAR surveying costs, payroll expenses for new employees, and an affiliate allocation during the period the new rate would be in effect. Once those expenses became known and measurable, even as late as at the Commission hearing, the Commission cannot completely ignore that available evidence of actual post test-year data; they might deem it insignificant, but they are not required to deem it inadmissible. An historic test year may not represent current costs but rather "establish[es] with a reasonable degree of accuracy the revenue and expenses that a utility will experience during the period when the new rates will be in effect." *Nw. Pub. Serv. Co.*, 297 N.W.2d at 469. When the test year expenses are called into question by concrete evidence of actual post test-year experience, ARSD 20:10:13:44 allows adjustments so that the cost of service is more accurate.

BHII argues the fact that these three budget amounts were later adjusted is irrelevant; that because those expenses on the initial cost of service statement were unsupported budget values, they should have been rejected, and they cannot later be resurrected by evidence of the actual experience after the initial application is filed. This argument runs contrary to the holding of *Nw. Pub. Serv. Co.* and *In re Minnesota Gas Co.* While a rate cannot be based on predictions, the Commission cannot "ignor[e] available evidence of actual post test-year earnings" but "it should supplant evidence of a purely theoretical and predictive nature." *Nw. Pub. Serv. Co.*, 297 N.W.2d at 469.

Once the actual values of these three expenses were known and measurable, BHP proposed an adjustment to the test year amount, fully supported the change, and the Commission approved it. The Commission's interpretation of ARSD 20:10:13:44, as well as SDCL 49-34A-6[14] and SDCL 49-34A-8[15], contemplate and permit these adjustments for determining just and reasonable rates. Because this Court finds that adjustments of costs known after filing the initial application are permissible, it will not reverse the approval of the Settlement based on these known and measurable expenses.

"Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in BHP's filed case." *Id.* at 2. Some of these adjustments were proposed after the initial application was filed, but were not identified by BHII on appeal. *See generally Orig. Settl. Memo* at 2-15. One example is the adjustment to the Neil Simpson Complex Common Steam Allocation. (*See BHP Br.* at 15 for two other examples.) Staff replaced budget numbers for the Steam Allocation with actual costs ending August 2014; hence the adjustment was based on values not known until after the date of filing the application. *Id.* at 9. This adjustment had the effect of *reducing operating expense*, but of course, was not one identified by BHII as a ground for reversal in this appeal. In fact, BHII's expert, Lane Kollen, concurred with this adjustment. *Kollen Testimony,* at 49. The point here is that if BHII was correct in its interpretation, new expenses that actually reduced rates would be equally inadmissible as expenses that raise the rates. The argument, therefore, ignores the objective of just and reasonable rates.

Propose new costs

BHII offers another argument that by their interpretation of ARSD 20:10:13:44, "the rule does not permit a utility to use the mechanism for proposing adjustments as a tool to introduce new costs to its filed cost of service that were not known and measurable at the time the utility filed its application." *BHII Br.* at 21 (no new line-item increases). BHP argues that "[f]or the few categories of costs that were not incurred during this time period, those costs are known with reasonable certainty and measurable with reasonable accuracy." *BHP Br.* at 11. None of the rules or statutes differentiates between adjustments of costs incurred during the

---

[14] "Every rate made, demanded or received by any public utility shall be just and reasonable." SDCL 49-34A-6.

[15]
> [The Commission] shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its *total current cost of furnishing such service*, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

SDCL 49-34A-8 (emphasis added).

test year and adjustments of costs that were not incurred until after the test year. The same practical and reasonable interpretation necessitates equal treatment of the new costs. The new costs adjusted in the Amended Settlement Stipulation would be effective within 24 months of the end of the test period, thus even for new costs, ARSD 20:10:13:44 allows their adjustment when the result is a just and reasonable rate.

No Due Process Violation

From a functional standpoint, allowing adjustments as they become known and measurable is practical and results in using the most current known costs in the calculation of a just and reasonable rate. BHII contests this assertion by describing how it is actually impractical, arguing that allowing adjustments during the pendency of the action makes the revenue requirement calculation a "moving target subject to continuous updates" until the day of final decision. BHII argues this "undermine[s] due process because ratepayers would never know exactly what revenue requirement the utility was proposing."[16] *BHII Br.* at 19.

Appellees admit that its interpretation may result in changes until the day the Commissioners vote;[17] however, they assert that no due process violation occurs because the nature of the cost of service analysis is a forward-looking device that is inherently imprecise. Also, Appellees assert that ratepayers will always know the maximum amount of the increase because the implemented rate cannot be higher than the initial proposed amount.[18] Appellees further offer that all notice requirements were followed to inform the parties of adjustments and BHII (and DRA) were given the opportunity to be heard.

BHII responds that due process is not met by submitting an inflated application with "everything but the kitchen sink" included. This, they argue, encourages padded numbers, including budget amounts, or adding place-holder costs that are wholly unsupported in the record and which the utility can continuously change until the day of decision. *BHII Reply Br.* at 9 (reasoning that "it is not enough, however, for ratepayers to know the maximum potential increase if the utility's application is padded with budgets and estimates it cannot prove at the time of filing.") As evidence of the inflated nature of the initial Application, BHII emphasizes that BHP proposed a $14.6 million rate increase but only $6.89 million was approved.

---

[16] No authority is offered to support the argument that due process requires all parties to know the exact cost of service and revenue requirement during the entire rate case litigation. While the rule that the "[f]ailure to cite authority is waiver of an argument" is a Supreme Court rule and not binding here, nonetheless, it is illustrative that BHII cannot cite any cases directly supporting their argument, especially when notice was given to BHII for every adjustment proposed.
[17] *PUC Br.* at 15.
[18] ". . . In no event shall the rates exceed the level of rates requested by the public utility. . . ." SDCL 49-34A-21.

The Court does not see this as a due process issue and declines to reverse the Settlement when notice and opportunity to participate were provided. Ratepayers have every right and opportunity to intervene, participate, litigate, and appeal. The fact that the outcome is uncertain to some extent, merely lands this case alongside virtually every other lawsuit in the courts. So long as the affected parties have notice of the dispute, and have the opportunity to participate fully, they are getting all the process which is due.

Conclusion for Issue I

"The burden is on the public utility to establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers in this state." SDCL 49-34A-8.4. The Court gives the Commission a reasonable range of informed discretion in the interpretation and application of ARSD 20:10:13:44 because the agency's interpretation is one of long standing (in case any interpretation was needed in the first place, which it wasn't). The Commission's interpretation and application of this Rule was correct when considered together with the Commission's expertise in applying the Rule. Combining the long-standing practice of considering adjustments during the pendency of the case, the practicality of such practice, the full evidentiary support of these adjustments, and the harmonious construction of the regulatory scheme with related statutes, the Commission did not err by permitting the proposed adjustments.

II.

Whether the Commission erred by using 2010–2014 in its five-year normalization calculation for pension expenses instead of 2011–2015?

BHP's pension expense varies significantly year-by-year. The 2013 test year pension expense was $2,844,759; in 2014, it was only $976,122; 2012's pension expense was $3.25 million. FOF 41. BHP suggested a normalization adjustment based on the average annual expense of "the most recent five-year average of actual costs", which at the time of the adjustment was from 2010 to 2014, equaling $2,336,305. By late December 2014, however, BHP knew its 2015 actual pension expense, but the Commission still approved the pension expense adjustment for 2010 to 2014. At the hearing below, BHII objected to this treatment, but the Commission found that the normalization method was consistent with sound regulatory principles and accepted the average for the cost of service analysis.

On appeal, BHII argues that if the Commission can accept adjustments after filing the application—if Appellees' interpretation of ARSD 20:10:13:44 prevails in Issue I—then the Commission must use the actual known and measurable data from 2015, so that the five-year range used for normalization is from 2011 to 2015 (reducing the revenue requirement by $173,855).

Appellees assert that this is not reviewable because no evidence was presented below about the reasonableness of the 2011 to 2015 average for pension expense. Appellees also argue this issue was not timely raised on appeal because BHII never presented any evidence on 2015 data and did not make this argument until after the contested hearing. BHP argues BHII only submitted evidence that 2014 data, alone, was appropriate without normalization and never presented evidence that 2011 to 2015 was the more appropriate period than 2010 to 2014 period. BHP concludes that the Commission did not have the opportunity to review evidence regarding whether the use of 2011 to 2015 data was a better reflection of total current pension costs than 2010 to 2014, and thus this court should not address the issue.

First, this issue is reviewable. Evidence was submitted to the Commission on this issue. The actual 2015 data was presented to the Commission, although not by BHII, but by BHP's witness Thurber, who testified that BHP's "actual total company 2015 pension expense is $2,056,581. The actuarial calculation was provided as a Supplemental Response to SDPUC 2-13." *Thurber Rebuttal* at 22, App. A-389. BHII's Post-Hearing Brief to the Commission dated February 17, 2015 argued for including 2015 in the normalization calculation:

> Should the Commission reject BHII's interpretation of ARSD 10:20:13:44 [sic] and allow post-filing adjustments to costs included in the test-year, the Commission should require BHP to incorporate two additional changes. First, the Commission should incorporate 2015 into the five-year average of pension expense. . . .
>
> According to Mr. Thurber, BHP's five year average (years 2010 through 2015 [sic]) for pension expense cost is $2,336,305. *Thurber Rebuttal* at 21 (should be 2014). As support for beginning to use a five-year average, Mr. Thurber points to the fact that the Company now knows the pension expense for 2015. He testified that 'Black Hills Power's actual total company 2015 pension expense is $2,056,581.' *Id.* at 22. If the Commission is inclined to use the most current information, Mr. Thurber's table on page 21 of his rebuttal testimony should be revised to delete the year 2010 and add the year 2015 for purpose of calculating the five year average. The revised five year average would be $2,162,451. . . .

Post-Hearing Br. at App. A-124-25. This very point was addressed by the Commissioners at their March 2, 2015 meeting. *See Post-Brief Hr'g Tr.* at 4-7 (March 2, 2015) at Co. App. A-136-39 (Commissioners asking questions and discussing whether the 2015 actual pension expense shows continued volatility of the expense in light of freezing their pension plan); *see also Petition for Reconsideration,* Reply App. 166, 191-92.

In its Brief on appeal, BHP argues that "the Commission considered the data from 2015 in determining whether the normalization of pension expense using costs from 2010-2014 was proper", not whether using 2015 in the normalization calculation would result in a just and reasonable rate. *BHP Br.* at 23.

The Commissioners considered the 2015 data and whether it still showed the pension expense was fluctuating and whether 2010 to 2014 was reasonable. The Commissioners had the opportunity to request more information or testimony, if needed, to determine its effect on the rate. But instead, the Commissioners did not find it necessary to adjust for the known 2015 expense.

There are really two inter-related issues here: one, in light of concluding that adjustments can be made during the pendency of the case in Issue I, is the Commission *required* to accept all adjustments with actually known and measurable data as it comes available? (What if the new figure is either anomalous, or irrelevant by dint of being no different than the prior data? Are the commissioners still bound to "plug in" data which they discount or distrust for whatever reason?) And two, whether the Commission's factual finding that the five-year normalization calculation 2010 to 2014 was "just and reasonable" without including the 2015 actual data? The first issue requires the same standard of review as Issue I, *de novo* for statutory and regulatory interpretation. The second issue on the Commission's factual finding is subject to clear error review.[19] The Court will only reverse a finding when it is "firmly convinced a mistake has been made." *Hayes*, 2014 S.D. 64, ¶ 7, 853 N.W.2d at 881.

BHII argues that if the Court approves the Commission's interpretation of ARSD 20:10:13:44, the Commission is *required* to adjust when it has actual data of the most current costs of service. BHII cites no authority or law *mandating* the Commission to use the most recent data and absolving its duty of determining a "just and reasonable" rate.

---

[19] BHII argues that the 2015 actual data was documentary evidence; therefore, whether this was a finding of fact or conclusion about interpreting a Rule, the Court's review should be *de novo*. While it is true that documentary evidence can be reviewed de novo by an appellate court, findings based on live testimony are reviewed for clear error. *Tucek v. Dep't of Soc. Servs.*, 2007 S.D. 106, ¶ 13, 740 N.W.2d 867, 871. In this case, three witnesses testified, both in case-in-chief and as rebuttal. BHP witness Thurber (TR. at 132-33); BHP witness White (TR. at 86-87; *see* BHP Exhibit 21); Staff witness Peterson (Peterson Direct, *Exh. Staff* 1 at 16-17; TR. at 282-83); and BHII witness Kollen (TR. at 175, 184, 210, 214-16).

At the heart of SDCL 49-34A-6, -8 and ARSD 20:10:13:44 is the underlying objective of finding the most "just and reasonable" rate, the best representation of future costs. In other words, if the 2010 to 2014 range is a better representation of the future expense incurred during the time the new rate is in effect, and 2015 was an anomalous year for pension expense, BHII's interpretation would require the Commission to ignore a more reasonable rate and impose a less representative cost. Without any citing authority[20] *requiring* the Commission to accept certain adjustments and absent express language in the Rule to that effect, the subjective nature of the Commission's duty of finding a "just and reasonable" rate is paramount. Also, BHII presents no evidence that 2010 to 2014 is unjust or unreasonable. The Commission adopted Peterson's testimony on this point and found the normalization using 2010 to 2014 was just and reasonable.[21]

"The test-year concept is designed to produce a measure of a regulated utility's earnings for a known period of time, to enable the regulatory body to make an accurate prediction of revenues and expenses in the reasonably near future. Based upon the evidence presented, "*the regulatory body undertakes a reasoned exercise of its discretion in altering test-year data to reflect changes of known magnitude occurring subsequent to the test year*." *Nw. Pub. Serv. Co., v. Cities of Chamberlain, et al.*, 265 N.W.2d 867, 878 (S.D. 1978) (citing *Nw. Bell Telephone Co. v. State of Minn.*, 253 N.W.2d 815, 822 (Minn. 1977)) (emphasis added).

Although neither party argues on the subjective nature of determining a rate, that really answers the question. The Commission has discretion to balance the interests of the ratepayers with the interests of the utility to find what is "just and reasonable" according to the Commissioners' expertise. The standard of review is not whether adding 2015 proves that the 2010 to 2014 average was unfair. Instead, the standard is whether, based on the entire record, this court "is definitely and firmly convinced a mistake has been made." *Otter Tail Power Co.*, 2008 S.D. 5, 26, 744 N.W.2d at 602. Based on the entire record, the Court is not firmly convinced that the Commission erred when finding that the normalization calculation using 2010 to 2014 resulted in a just and reasonable rate.

---

[20] No authority is offered to support this position except a corollary argument for consistent application of ARSD 20:10:13:44 with the Court's ruling on Issue 1. While the "[f]ailure to cite authority is waiver of an argument" and fatal of the issue at the Supreme Court level, it is illustrative to this Court that BHII cannot cite any rules or statutes that expressly mandate the Commission to use each and every current cost regardless of whether it would make the end result unreasonable. Inherent within the Commission's discretion is the *forecasting* of which data (2010 to 2014 or 2011 to 2015) are most likely to be repeated in the future. This court is reluctant to second guess that forecast. Commissioners are free to pick the data most trusted or representative.

[21] "An understatement of BHP's pension costs could place the Company in a significant under-recovery position necessitating more frequent rate increases. With a highly variable cost such as the pension expense, to avoid wide swings in over-recovery and under-recovery of the underlying expense, it makes sense to employ a normalization procedure, such as that reflected in the settlement . . . unless there is an extraordinary event that makes a five-year normalization method unreasonable." *Peterson Direct, Exh. Staff* 1 at 17.

The Commission posited the argument that the actual data was known *too late* to be included. At first, this argument does not make sense in light of the Commission's prior admission that their interpretation of the adjustment Rule may allow adjustments up to the day of the Commission's Final decision. *PUC Br.* at 15. But at oral argument, the Court (and BHII) learned for the first time of an internal cut-off date set by Staff for accepting adjustments to the cost of service. The purpose of this internal regulation is practicality and administrative only. The Commission explained that if an adjustment comes in too close to the date set for decision and would have a *de minimis* (too minor to merit consideration) effect on the rate, then, in its discretion, it will not accept the adjustment. The Commission's position is that the amount of the adjustment and its overall effect on the rate must be significant enough to expend the time and money making the adjustment to the cost of service and then to change the revenue requirement (if revenue-producing) under the matching principle. This practice continues to reflect the discretionary balancing act the Commission must do when determining a fair end result and a just and reasonable rate.

III.

Whether the Commission erred when it included $888,000 of BHP's incentive compensation package expense in its cost of service analysis?

BHII asserts that the inclusion of the $888,000 adjustment for incentive compensation expense was not fully supported, thus BHP did not meet its burden of proving that, by a preponderance, this adjustment is "prudent, efficient, and economical and [is] reasonable and necessary to provide service to the public utility's customers in this state." SDCL 49-34A-8.4; *Irvine v. City of Sioux Falls*, 2006 S.D. 20, ¶ 10, 711 N.W.2d 607, 610 (the burden of proof for administrative hearings is preponderance of the evidence). In the parties' briefs, it was agreed that the standard of review is clear error; however, at oral argument, BHII argued this issue should be reviewed *de novo*. The Court finds this issue to be one reviewed for clear error, but even if BHII is correct and the review is *de novo*, it would not change the Court's holding.

The specific evidence BHP offered to support this adjustment was a discovery response to Staff Request 2-11, a fund schedule, Attachment 2-11G (Confidential). AR. at 6340. Also, BHP witness White testified that in his opinion, BHP's "programs are prudent and necessary to attract and retain and motivate employees." TR. at 56. He further testified that disallowing the amount on line 6 of the Attachment 2-11G "would result in a very unfair rate of return on equity for [BHP]." TR. at 57. While White could not specifically answer what document or exhibit or evidence supported the amounts in Attachment 2-11G, White believed that through its submitted books and records, the Application, formal and informal discovery, and the expert testimony, BHP has met its burden by showing that BHP has "incurr[ed] these costs in a prudent way and meeting [its] obligation to serve."

TR. at 59. BHII faults BHP for not providing work papers to support Attachment 2-11G. While the Commission did not make a specific finding regarding whether this was sufficient evidentiary support, it did find that including the incentive compensation plan did "not render the Amended Stipulation unjust and unreasonable." FOF 40. This finding is well-supported by the testimony of Patterson, White, and Peterson.[22] Even if the Court's standard of review were *de novo*, as suggested by BHII, the Court would still affirm the inclusion of the incentive plan expense to make a just and reasonable rate.

BHII argues that the inclusion of incentive compensation expenses makes the resulting rate unjust and unreasonable, yet BHII does not explain why this expense cannot be passed on to the customers if it encourages retention of employees and results in better service. BHP offers that there is no legal authority and no reason why an incentive compensation plan cannot be included in the cost of service, regardless of it being connected to performance or retention. The Commission agreed and concluded, "No statute or rule precludes the inclusion of employee incentive compensation in the utility's cost of service and revenue requirement. The Commission's decision whether to allow incentive compensation and, if so, subject to what limitations are judgment calls concerning what meets the just and reasonable standard." COL 12. BHII seems to limit the application of "just and reasonable" to

[22] BHP provided testimony from several witnesses who discussed the incentive compensation plan and the reasonableness of recovering that expense in this rate case. BHP witness Laura Patterson explained the purpose of the incentive compensation plan and the adjustment. She testified about many studies (Towers Watson study, BHC Human Resources review, Aon Hewitt, Mercer, the Edison Electric Institute, etc.) that provide market incentive compensation comparisons. *BHP Exh.* 22. She also stated that while there is no case law precedent for including the expense, commissions "in Nebraska, Iowa, Wyoming and Colorado in both gas and electric rate cases have approved this employee compensation and benefit structure." *Id.* at 22.

In his rebuttal testimony, Kyle White testified that the inclusion of this expense has not been shown to be "imprudent or unreasonable based upon what the market pays employees for similar positions." *BHP Exh.* 65. White summarizes Patterson's testimony that restricted stock is not tied to financial performance, because "once restricted stock is granted to a key employee, the only requirement for pay-out is the employee's continued employment." *Id.* at 12. White also explained that there is no justification for excluding the entire expense (the additional $888,000), but it would have a "punitive outcome for the Company for utilizing normal and reasonable employee compensation practices that are prevalent across the utility industry and other companies in the Black Hills region." *Id.* at 13.

David Peterson explained that the parts of the plan that were performance-based were excluded from the cost of service (equally an exclusion of $666,000), so BHP is not requesting ratepayers pay for performance-based incentive plan. TR. at 284-87. For the other part of the plan included in the cost of service analysis, Peterson testified that BHP does not have financial triggers in that incentive compensation plan, so it is reasonable to include that expense which is not tied to performance measures. *Id.*; Peterson Direct, *Exh. Staff* 1 at 17-18 ("the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, I supported the exclusion that is contained in the settlement and recommend that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time.")

the perspective of ratepayers only, yet clearly the Legislature intended that the rate also be just and reasonable to the utility as well.

The Commission's responsibility is to apply the criteria of SDCL 49-34A-6 and -8, and judge the rate as a whole. The cost of service analysis and the revenue requirement is the result of a give-and-take negotiation and settlement. The Commission found that, having included the incentive compensation expense, the rate was still just and reasonable. The Court is not definitely or firmly convinced that the Commission erred when it included this expense, nor would it reverse under a *de novo* standard. The adjustment was fully supported and this Court affirms the finding.

CONCLUSION

For the foregoing reasons, the Commission's decision is AFFIRMED.

Dated this 8th day of January, 2016.

Mark Barnett

____
Honorable Mark Barnett
Sixth Circuit Court Judge

20:10:13:43. Cost of service under the new rates. The initial application for a rate increase under this chapter shall include a cost of service study by customer class of service, by rate classification, if so ordered, or other appropriate categorization showing revenues, costs, and profitability for each of the rate categories, identifying the procedures and underlying rationale for cost and revenue allocations.

Source: 2 SDR 90, effective July 7, 1976; 12 SDR 151, 12 SDR 155, effective July 1, 1986.

General Authority: SDCL 49-34A-4.

Law Implemented: SDCL 49-34A-10, 49-34A-12, 49-34A-41.

20:10:13:44. Analysis of system costs for a 12-month historical test year. The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period.

Source: 2 SDR 90, effective July 7, 1976; 9 SDR 55, effective November 7, 1982; 12 SDR 151, 12 SDR 155, effective July 1, 1986.
General Authority: SDCL 49-34A-4.
Law Implemented: SDCL 49-34A-10, 49-34A-12, 49-34A-41.

20:10:13:104. Testimony and exhibits. A utility filing for an increase in rates and charges shall be prepared to go forward at a hearing on reasonable notice on the data, testimony, and exhibits which have been submitted and sustain the burden of proof of establishing that its proposed charges are just and reasonable and not unduly discriminatory or preferential or otherwise unlawful. In addition to the material the utility chooses to submit as part of its case, except for

(1) Increases filed under § 20:10:13:26;
(2) Increases resulting from changes made in fuel clauses or gas adjustment clauses; and
(3) Increases of rates comprising an integral part of coordination and interchange arrangements in the nature of power pooling transactions.

The exhibits shall include full cost of service data, as identified in §§ 20:10:13:51 to 20:10:13:102, inclusive. Although §§ 20:10:13:51 to 20:10:13:102, inclusive, provide for a historical test period, the utility, in addition, may submit cost of service information for a nonhistorical test period beginning no later than the proposed effective date of the new rates. Statements A through R and the accompanying testimony shall include an explanation of these exhibits.

Source: 2 SDR 90, effective July 7, 1976; 12 SDR 151, 12 SDR 155, effective July 1, 1986.
General Authority: SDCL 49-34A-4.
Law Implemented: SDCL 49-34A-10, 49-34A-12, 49-34A-13, 49-34A-41.

49-34A-6. Rates to be reasonable and just--Regulation by commission. Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.

Source: SL 1975, ch 283, § 16.

49-34A-8. Criteria for determination of rates by commission. The commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its total current cost of furnishing such service, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

Source: SL 1975, ch 283, § 16; SL 1976, ch 296, § 9; SL 2007, ch 269, § 1.

49-34A-8.4. Burden on public utility to establish criteria for determination of rates. The burden is on the public utility to establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers in this state.

Source: SL 2007, ch 269, § 2.

49-34A-19. Costs and revenue considered in determining rates--Acquisition cost of property as alternative--Projected income and expenses. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the Public Utilities Commission shall use the depreciated original cost of the property. However, the commission may alternatively use the full acquisition cost of any property acquired by the utility after the property was first devoted to public use. Full acquisition cost of such property shall be used if:

(1) The utility makes application prior to acquisition;
(2) The commission holds a hearing;
(3) The commission finds that the cost of acquisition is prudently incurred; and
(4) The commission finds that the acquisition will provide benefits to the utility's customers.

In determining the revenue requirement the commission shall consider revenue, expenses, cost of capital and any other factors or evidence material and relevant thereto. The commission may take into consideration the reasonable income and expenses that will be forthcoming in a period of twenty-four months in advance of the test year.

Source: SL 1975, ch 283, § 12; SL 1976, ch 296, § 18; SL 1982, ch 330; SL 1990, ch 375.
