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Docket #(s): G-02528A-05-0314

G-02528A-03-0205

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S-1, S-2, S-3, S-4, S-5, S-6, S-7

EXHIBIT A-1 Admitted 12-15-05

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	DOCKET NO. G-02528A-03-0205

DIRECT

TESTIMONY

OF

JOHN V. WALLACE

DUNCAN RURAL SERVICES CORPORATION

June 9, 2005

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I. INTRODUCTION

Q. Please state your name address and occupation.

A. My name is John V. Wallace. I am the Director of Regulatory and Strategic Services of Grand Canyon State Electric Cooperative Association (GCSECA). I represent Duncan Rural Services, Inc. (DRSC or the Company).

Q. Please describe your professional qualifications and experience.

A. I have been the Director of Regulatory and Strategic Services since August 1, 2000. In this position, I am responsible for preparing rate, financial and other utility related analysis and testimony for all of the GCSECA member Arizona Electric Cooperatives. Before I accepted a position with GCSECA, I worked for the Arizona Corporation Commission (ACC) for approximately 10 years. While working for the ACC, I held a number of positions within the Accounting and Rates Section of the Utilities Division of the ACC; the last of these positions was Manager, Revenue Requirements Analysis. In this capacity, I was responsible for managing six analysts and preparing staff reports and testimony on Certificate of Convenience and Necessity (CC&N), financing, rate and other utility matters. In addition to my work experience, I have a Masters Degree in Business Administration from the University of North Dakota.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the applicant, DRSC. As discussed by Mr. Shilling in his direct testimony, DRSC provides gas service to approximately 760 customers in Greenlee County, Arizona.

Q. Was this testimony prepared by you or under your direction?

A. Yes, it was.

Q. What exhibits are you sponsoring in this case?

A. In addition to the schedules attached to this testimony, I am responsible for the preparation of all the test year materials contained in DRSC's filing, except for the historical financial statements prepared by DRSC and the report of its Certified Public Accountants. I will be referring to these materials from time to time throughout my direct testimony.

Q. What areas does your testimony address?

A. My testimony addresses four primary areas: revenue requirements, cost of service and class revenue allocations, rate design, additional long-term debt, and reorganization.

Q. Please summarize your recommendations.

A. Mr. Shilling has discussed in his testimony the reasons underlying the Company's request for an overall 22.70% increase in revenues. An increase of this magnitude is needed to eliminate the large negative margins produced by the current rates, to provide adequate interest and debt service coverage's and to provide the internally generated cash flows required to support the utility's on-going plant improvement program.

Q. Please explain Schedule A-2 of the filing.

A. Schedule A-2, page 1 of 2, summarizes operating results at present and proposed rates for the 12 months ended December 31, 2004, the test year in this case. The present rates produced a net/total margin deficit, or loss, of $77,970 on an adjusted test year basis. The proposed $147,406 increase in revenues produces a positive net/total margin of $30,845 and a corresponding times interest earned ratio (TIER) of 2.00 in contrast to the current negative net TIER of 1.51.

Q. Do you view the indicated net TIER of 2.00 at proposed rates as a reasonable ratio in this case?

A. Yes. The 2.00 TIER requested in this case is, in my view, at the lower end of a reasonable TIER range for this utility in view of its negative equity, the need to reverse the losses it is experiencing most every month, and as discussed later in my testimony, the need to produce positive cash flows.

Q. Why is an increase in revenues of this magnitude needed?

A. This revenue increase is needed primarily to pay for the higher cost of purchased gas. In its previous rate case, the Commission approved a base cost of gas of $0.36 per therm. As of the December 31, 2004, DRSC's base cost of gas per therm was $0.56. This results in an $118,666 increase in the Test Year Purchased Gas Expense and accounts for the majority of the $147,406 proposed increase in revenues. DRSC has experienced major price increases in the spot price of natural gas during and after the Test Year.

According to DRSC's audited financial statements, DRSC also had a deficiency in total margins of $18,859 at December 31, 2003 and a deficiency in total margins of $49,639 at December 31, 2004. At current revenue levels, this deficiency will likely increase to approximately $70,000 before new rates can be approved by the Commission. Moreover, DRSC filed with this rate application a request for approval to borrow an additional $268,988 thereby increasing its long-term indebtedness to $772,408. The proposed $147,406 increase in revenues is needed to provide adequate TIER and debt service coverage ratios on the increased debts and expenses and to eliminate the deficiency in margins and equities.

Q. Why is DRSC seeking to incur more indebtedness at this time?

A. In general, this additional debt is needed to reimburse Duncan Valley Electric Cooperative, Inc. ("DVEC") for funds supplied to DRSC over the past 4 years for improvements to the gas distribution system. A more detailed discussion of this requested borrowing is contained in the financing portion of my testimony. This long-term debt would have a variable interest rate (assumed 6 percent) with repayment over 25 years.

Q. Would DRSC be able to borrow long-term debt directly from National Rural Utilities Cooperative Finance Corporation ("CFC") or another third party lender on its own credit?

A. No. CFC or any other lender will require all lending to DRSC to be guaranteed by DVEC since DRSC is not a full member of CFC and, in any event, the Company's poor financial condition does not enable it to incur additional debt on its own credit. The increase in revenues sought in this case will be an important step towards restoring the credit worthiness of the utility.

Q. Please summarize your rate design recommendations.

A. As approved in DRSC's last rate case, I am recommending customer classes be based on three-meter size ranges rather than by residential, irrigation and commercial. I believe that a rate design based on meter size is more equitable for all customers. I am also recommending that winter and summer per therm rates be continued for each of the three-meter classes. I am recommending monthly service charges that were based on the cost and demand associated with the different meter sizes. Finally, I am recommending that all three-meter classes pay same per therm winter and summer rates.

I am recommending no change to the three customer classes based on meter size:

250 cubic feet per hour (cfh) & below

Above 250 cfh to 425 cfh

425 cfh to 1,000 cfh

I set the monthly service charges at $20 for the 250 cfh & below meter size, $30 for above 250 cfh and up to 425 cfh meter size and $40 for above 425 cfh to 1,000 cfh the largest meter size. Meter sizes above 1,000 cfh would be provided service on a contractual basis. (Refer to Schedule H-3)

After determining the amount of additional revenue that resulted from the increase in the monthly service charges listed above, I increased the per therm rates for summer and winter by an equal percentage to collect the remainder of the revenue requirement. I am recommending that the per therm rates for summer and winter be the same for all three classes. The DRSC recommended summer rate is $0.80580 per therm, and the winter rate is $1.25405.

I am recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) and late/deferred payment percentage of 1.5 percent per month that was approved in DVEC's recent rate case (Decision No. 67433, dated December 3, 2004). I am not recommending any other changes to the current service charges. The present and proposed service charges are detailed on the bottom of Schedule H-3.

II. REVENUE REQUIREMENTS

Q. Please explain the Original Cost Rate Base (OCRB) calculation shown on Schedule B-1.

A. I have made one pro forma adjustment to rate base increasing the amount of customer deposits by $3,139 from $16,925 to $20,064 to reflect the interest accrued on customer deposits. I have subtracted the $20,064 of customer deposits and $19,554 of net deferred taxes from DRSC's rate base. DRSC is recommending an OCRB of $772,408.

Q. Why hasn't DRSC included its Reconstruction Cost New less Depreciation (RCND) information (Schedules B-3 and B-4) in its application?

A. DRSC stipulates that the Commission may use its original cost data for the calculation of a rate of return on fair value for this proceeding. Therefore, the RCND information contained on Schedules B-3 and B-4 is unnecessary for a determination of this matter.

Q. Why hasn't a provision for working capital (Schedule B-5) been included in the development of rate base?

A. The Company decided not to incur the additional expense required to conduct a lead/lag study since its revenue request is based on Times Interest Earned Ratio (TIER), consistent with the method used by the Commission in deciding revenue requirements in the last case, and not a return on rate base approach to ratemaking. Accordingly, no working capital allowance is sought in this case.

Q. Please explain Schedule C-1 of the filing.

A. Schedule C-1 shows the actual and adjusted operating income statement for the test year. As described on Schedule C-2, actual test year results were adjusted as follows:

Adjustment A. increased revenues to reflect $118,453 of purchased gas fuel cost that was collected through DRSC's fuel adjustor mechanism during the Test Year. As a result of DRSC's recommendation to raise its base gas cost to $0.56 per therm in this case, base rate revenues will be increasing by approximately $118,000.

Adjustment B. increased several expenses were increased by a total of $13,068 to annualize the 4 percent increase in salary and related benefits that occurred in July 2004.

Adjustment C. increased Regulatory Commission Expense by $5,281 for actual and estimated rate case expenses that will be incurred in the preparation and completion of this case. I have estimated the total amount of rate case expense and ongoing regulatory expenses to be approximately $16,000 per year.

Adjustment D. decreases Income Tax Expense by $30,302 from a negative $158 to a negative $30,460. Included in this adjustment is the removal of a negative $158 that was loss carry-forward that has expired as well as an adjustment of $50 for an income tax filing fee and an adjustment of a negative $30,194 to reflect the Adjusted Test Year Income Tax Expense.

Adjustment E. increases Interest Expense on Long-term Debt (LTD) by $16,139 to account for the additional interest of 6% on the $268,988 of additional LTD to be used to pay down the accounts payable to DVEC that DRSC has used to fund its construction expenditures and plant additions.

These adjustments in total increase net margin for the test year by $114,267 resulting in an adjusted deficit in total/net margins of $77,970.

Q. Please explain the DRSC's Income Tax Expense for its proposed level of revenues and expenses as contained on Schedule A-2, page 2 of 2.

A. DRSC is a "C" Corporation and subject to federal and state income taxes. Based on the operating income level that results from DRSC's proposed rates, DRSC will have an Income Tax Expense of approximately $8,132 as shown on Schedule A-2, page 2 of 2.

III COST OF SERVICE AND RATE DESIGN

Q. Why should gas rates be based upon cost of service?

A. Cost of service is an important criterion in the development of revenues by class of consumer and the development of rates that will produce those revenues. If rates are not cost based, the inevitable results are subsidies among the classes of consumers and consumers within a class. This is not only perceived as inequitable, but may result in distorted consumer decisions concerning the use of utility services. Other factors, such as spot gas prices in winter vs. summer, continuity, simplicity and stability are valid considerations in the rate design process and had to be considered given DRSC's circumstances.

Q. Did you prepare the class cost of service analysis contained in the filing?

A. Yes. The study was prepared to provide guidance in setting class revenue targets and designing the rates required to meet these targets. The costing methodology used is essentially the same as that used in the last rate proceeding. As recommended by Staff in DRSC's last rate case and to limit the differences between DRSC and Staff in this case, I am using Staff's 100 percent demand allocation for mains. Additionally, the rate design I am recommending relies less on the cost of service analysis and more on other rate design factors as explained later in my testimony.

Q. Would you briefly describe the approach used to develop the study?

A. The basic method used in the study is commonly known as the embedded or average cost method as contrasted with the marginal cost method. This method, properly applied, produces a guide for ratemaking purposes.

The initial step was to establish, for costing purposes, consumer classes with similar usage characteristics. For the purposes of present rates these classes are: 250 cubic feet per hour (cfh) & below (residential and small commercial), above 250 cfh to 425 cfh (commercial and irrigation) and 425 cfh to 1,000 cfh (schools and large commercial). The next step in the study was to classify all elements of rate base and classifications of operating expenses as demand-related, commodity-related or customer-related. The results of this process are shown on Schedules G-6 and G-7. The final step in the analysis was to allocate rate base and operating expenses to each class of consumer. The results of these allocations are shown on Schedules G-4 and G-5. Functionalization and class allocation factors used in the study are provided on Schedule G-8.

Q. How were the class allocation factors developed?

A. DRSC is a winter-peaking system, primarily due to the increased space heating requirements during the winter months. Due to historically low class usage in 2004, Class demand allocation factors were developed based on total therm sales for the five-month period of January through March and November through December 2004 as well as previous years. Average commodity usage was used as a proxy for class peak demands since peak-day measurements were not available. Class commodity allocation factors were based on total therm sales for the test year. Two customer allocation factors were developed: one based on total bills by class (unweighted) and the other (weighted) based on meter size.

Q. Please summarize the results of your study.

A. The results of my study, at present and proposed rates, are summarized on Schedules G-1 and G-2. At present rates, the 250 cubic feet per hour (cfh) & below, Above 250 cfh to 425 cfh and 425 cfh to 1,000 cfh classes are producing sizable negative returns. The return indices show the 250 cubic feet per hour (cfh) & below with a negative return of 4.82% and a return index of 0.79, or 79% of the system average return (a return index of 1.00) which is a negative 6.08%. The Above 250 cfh to 425 cfh class has a negative return of 15.38% and a return index of 2.53; the 425 cfh to 1,000 cfh class shows a negative return of 17.35% and a return index of 2.85.

Q. Please explain the rate of return index concept.

A. The rate of return index is a relative measure of class contribution to the system average rate of return. When the system rate of return is positive, an index below 1.00 indicates that a class's revenues are not sufficient to recover its cost of service, while an index exceeding 1.00 indicates that a class is over-recovering its cost of service. When the system rate of return is negative, an index below 1.00 indicates that a class is over-recovering its cost of service, while an index exceeding 1.00 indicates that a class's revenues are not sufficient to recover its cost of service.

Q. Typically the cost of service study is used as the basis to allocate revenues among customer classes. Did you use the cost of service study to allocate revenues to customer classes?

A. No. DRSC's circumstances merit a deviation from strictly using the cost of service study to set rates for the reasons discussed below.

Q. How did you allocate revenues to the customer classes?

A. The rate design that I am recommending resulted in an allocation of revenues to customer classes as explained further below. The 250 cubic feet per hour (cfh) & below class revenues were increased by approximately 25 percent. The Above 250 cfh to 425 cfh class revenues were increased by approximately 15 percent. Finally, the 425 cfh to 1,000 cfh class revenues were increased by approximately 24 percent (See Schedule H-1). The Above 250 cfh to 425 cfh class revenue increase of 15 percent is less than the other two classes because the majority of customers in this class use very little gas in the peak winter months.

Q. What changes in the existing rate design are you recommending?

A. A rate design based on meter sizes is more equitable for all customers and should be continued. I am also recommending that winter and summer per therm rates be continued for each of the three-meter classes. I am recommending monthly service charges that were based on the cost and demand associated with the different meter sizes. Finally, I am recommending that all three-meter classes pay the same per therm winter and summer rates. All of these rate recommendations affected the revenue allocation to each customer class.

Q. Why are you recommending that the customer classes be based on meter size be continued?

A. The cost and demand that a customer places on the gas system is more closely related to meter size than whether a customer is a residential, irrigation or commercial customer. The demand that any customer can place on the gas system is directly related to how much gas can flow through the gas system to the customer during peak winter months. The larger the meter, service line and mains, the larger the peak flow demand that a customer places on the system. Residential, irrigation and commercial customers with the same main, service line and meter size have the potential to place the same peak demand on the system, assuming that each of these customers use gas during peak periods.

Q. Do each of the customer's classes place a similar demand on the system during the five peak winter months?

A. No. The irrigation customers in the Above 250 cfh to 425 cfh class primarily uses gas during the off peak summer months. The Above 250 cfh to 425 cfh customers used 20,980 therms in the five peak winter months compared to 148,600 therms used by these customers in the other months. During the Test Year, DRSC's peak month for therm usage was February. In that month, irrigation customers used only 3,751 therms of the 83,019 therms sold to all DRSC customers.

Q. Please explain the new customer classes by meter sizes and how existing residential, commercial and irrigation customers will fit into these classes.

A. I am recommending the following three customer classes based on meter sizes:

250 cubic feet per hour (cfh) & below

Above 250 cfh to 425 cfh

425 cfh to 1,000 cfh.

Residential, commercial and irrigation customers will take service under one of these three classes on the basis of the size of their existing meter. Based on existing meter sizes, all residential customers (692) and most (47) commercial customers take service under the 250 cfh & below customer class. The 18 irrigation customers and one commercial customer will take service under the Above 250 cfh to 425 cfh customer class. Currently, only two meters of the school fit into the 425 cfh to 1,000 cfh customer class.

Q. What monthly service charges are you recommending by meter size and why?

A. I set the monthly service charges at $20 for the 250 cfh & below meter size, $30 for Above 250 cfh and up to 425 cfh meter size and $40 for Above 425 cfh to 1,000 cfh the largest meter size. Meter sizes above 1,000 cfh would be provided service on a contractual basis. (Refer to Schedule H-3)

I am recommending the monthly service charges be different by meter size because the fixed costs (meter cost, main size, etc.) to provide gas service generally are more as the size of the meter increases and larger meter sizes also place a larger demand on the system during the peak winter months (i.e. the 425 cfh meter costs approximately three times more than the 250 cfh meter, the 1,000 cfh meter is approximately 10 times the cost of the 425 cfh meter).

Q. What is the increase in revenues that will result from your proposed increase in monthly service charges?

A. The increases in the monthly service charges that I am recommending result in an additional $46,308 of revenues. The remainder of the $147,406 revenue requirement increase, $101,098, was collected from the increase in per therm usage charges that are discussed below.

Q. What winter and summer per therm rates are you recommending for all three customer classes?

A. I am recommending the winter per therm rate be set at $1.25405, and the summer per therm rate be set at $0.8058 for all three customer classes.

Q. Why is the winter per therm rate that you are recommending significantly higher than the summer per therm rate?

A. During the Test Year, DRSC's customers' peak monthly usage was 83,019 therms in February versus 25,644 therms in lowest month, October. DRSC gas system is built to meet its peak demand (capacity) in the winter months like December, January and February. Customers who use the gas system during peak winter months should pay a higher share of the demand (capacity) related costs than customers who predominantly use gas during summer months.

In addition, historically the spot price of natural gas has been considerably lower in the summer months versus the winter months, because the demand for natural gas nationally is the highest during the winter months. DRSC's purchased gas costs in October 2004 were approximately $0.51 per therm versus an average of approximately $0.70 per therm in the peak winter months of November and December. For the reasons stated above, it would be unfair to customers who primarily use gas during the off-peak summer months to use a rate structure that only has one therm rate per customer class.

Q. Why are you recommending the same winter and summer per therm rates apply to all customers?

A. I am recommending that the per therm rates for summer and winter be the same for all three classes because each customer class regardless of the type of customer that uses gas during summer months should experience a lower cost of gas during the off-peak summer months. There is very little difference in per unit variable costs of service 250 cfh & below versus Above 250 cfh and up to 425 cfh versus Above 425 cfh to 1,000 cfh customers. The only difference in the rates and charges to the three customer classes will be the monthly service charge.

Q. How were the summer per therm and winter per therm rates calculated?

A. The summer and winter per therm rates were increased by an equal percentage until the remaining revenue requirement increase of $101,098 (the remainder of the $147,406 revenue requirement increase after the proposed increases in the monthly service charges) was collected from the proposed summer and winter per therm rates.

Q. What is the effect of the proposed rates on the average monthly bill of a 250 cfh & below customer?

A. As shown on Schedule H-4, page 1 of 3, the monthly bill for a 250 cfh & below customer who uses 76 therms in the winter will increase by $23.58 (25.55%), from $92.28 to $115.86. These bill calculations include the PGA rate of $0.211 per therm in present rates, and the PGA rate has been eliminated in DRSC's proposed rates.

Q. What is the effect of the proposed rates on the average monthly bill of an Above 250 cfh and up to 425 cfh customer as well as other customers?

A. As shown on Schedule H-4, page 2 of 3, the monthly bill for an Above 250 cfh and up to 425 cfh customer who uses 262 therms in the winter will increase by $71.24 (24.77%), from $287.63 to $358.87. These bill calculations include the PGA rate of $0.211 per therm in present rates, and the PGA rate has been eliminated in DRSC's proposed rates.

Q. What is the effect of the proposed rates on the average monthly bill of an Above 425 cfh to 1,000 cfh customer as well as other customers?

A. As shown on Schedule H-4, page 3 of 3, the monthly bill for an Above 425 cfh to 1,000 cfh customer who uses 1,430 therms in the winter will increase by $357.56 (24.23%), from $1,475.73 to $1,833.29. These bill calculations include the PGA rate of $0.211 per therm in present rates, and the PGA rate has been eliminated in DRSC's proposed rates.

Q. What changes are you recommending to service charges?

A. I am recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) and late/deferred payment percentage of 1.5 percent per month that was approved in DVEC's recent rate case (Decision No. , dated November 2004). I am not recommending any other changes to the current service charges

IV. BASE COST OF GAS, PGA AND BANK BALANCE

Q. What are your recommendations regarding the base cost of gas?

A. I am recommending that DRSC's base cost of gas be set at $0.56678 per therm (purchased gas costs on Schedule C-1 of $325,260 divided by the total number of therms sold of 573,869 as found on Schedule H-1. The current base cost of gas approved by the Commission is $0.36 per therm. As mentioned previously, DRSC has experienced a significant increase in its purchased gas costs. The proposed level of base cost of gas is closer to the level that DRSC will pay for future purchased gas costs.

Q. Are you recommending that the PGA charge which is $0.211 per therm as of March 31, 2005 be set to zero?

A. Yes. DRSC's current bank balance as of March 31, 2005 is only approximately $20,000. Therefore, I am recommending that DRSC's fuel adjustor rate that is $0.211 as of March 31, 2005 be set at zero. If approved, the proposed base cost of gas of $0.56678 should continue to gradually reduce the current under-collected bank balance of approximately $20,000 in the months that the purchased gas cost is below the proposed base cost of gas.

V. FINANCING

Q. Why is DRSC seeking to incur more indebtedness at this time?

A. In general, this additional debt is needed to reimburse Duncan Valley Electric Cooperative, Inc. ("DVEC") for funds supplied to DRSC over the past four years for improvements to the gas distribution system. Over this four year period, DVEC has advanced funds to DRSC as needed for cash flow needs related to construction and paying expenses. Since its last rate case in 2000, DRSC has made the following plant additions by year:

2001 - $108,087

2002 - $106,194

2003 - $62,393

2004 - $54,620

This long-term debt would have an interest rate equivalent to the Arizona Electric Power Cooperative, Inc. (AEPCO) variable interest rate earned on funds with repayment over 25 years. AEPCO pays this interest rate to DVEC on funds that DVEC has deposited with AEPCO. DVEC has chosen this rate to charge DRSC because this is the rate of interest that DVEC would have earned on funds that were advanced to DRSC. This interest rate is variable and will depend on market conditions. DRSC's revenue requirement calculation in this case assumes a 6% interest rate because the loan is over a 25 year period. DRSC chose a 25 year term because that is the term of one of its other loans from DVEC and because of the revenue increase necessary to enable DRSC to pay the additional debt service that resulted from the 25 year term was affordable.

Q. DRSC's total accounts payable to DVEC equaled $455,352 on February 28, 2005. Why hasn't DRSC requested a higher loan be approved in this case to repay this amount?

A. The maximum loan that DRSC has requested is equal to its current recommended rate base of $772,408 minus its exiting approved debt of $503,420 which equals approximately $268,988. DRSC did not want to request a loan that would result in its total debt exceeding its proposed rate base of $268,988.

Q. How will DRSC repay the remaining accounts payable of $186,364 to DVEC?

A. DRSC will have to make payments on the $186,364 ($455,352-$268,988) remaining balance of accounts payable as funds are available. If a balance remains or continues to grow, DRSC will need to seek ACC approval of additional long-term debt and/or file a rate case.

Q. Will DRSC be able to pay the additional debt service on the additional $268,988 with the rate increase that DRSC is requesting?

A. Yes. The rates requested by DRSC in this rate application are predicated on the repayment of DRSC's existing debts as well as the $268,988 of additional debt. According to Schedule A-2, page 1 of 2, DRSC will maintain a TIER of 2.00 and a Debt Service Coverage Ratio of 1.38 even with the additional debt service from the $268,988 loan assuming a 6% interest rate.

Q. Would DRSC be able to borrow long-term debt directly from CFC or Rural Utilities Service (RUS) on its own credit?

A. No. As mentioned previously, CFC will require all lending to DRSC to be guaranteed by DVEC since DRSC is not a full member of CFC and, in any event, the Company's poor financial condition does not enable it to incur additional debt on its own credit. DRSC is not an eligible borrower of RUS. The increase revenues sought in this case will provide an important first step towards restoring the credit worthiness of the utility.

Q. What are the cash flow ramifications of this rate and financing application?

A. I urge the Commission to be mindful of this precarious cash flow condition when considering any modifications to the average increase in revenues requested in this case. While the increase requested by DRSC in this case is substantial, DRSC must collect this recommended level of revenues to pay its expenses, debts and fund future construction projects. As mentioned in Jack Shilling's testimony, DRSC can no longer rely on DVEC to advance DRSC funds for these purposes.

Q. Does that conclude your direct testimony?

A. Yes, it does.

EXHIBIT
A-2
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	DOCKET NO. G-02528A-03-0205

REBUTTAL

TESTIMONY

OF

JOHN V. WALLACE

DUNCAN RURAL SERVICES CORPORATION

November 21, 2005

I. INTRODUCTION

Q. Please state your name address and occupation.

A. My name is John V. Wallace. I am the Director of Regulatory and Strategic Services of Grand Canyon State Electric Cooperative Association (GCSECA). I represent Duncan Rural Services, Inc. (DRSC or the Company).

Q. Are you the same John V. Wallace who filed direct testimony in this matter?

A. Yes.

Q. Was this testimony prepared by you or under your direction?

A. Yes, it was.

Q. What areas does your rebuttal testimony address?

A. My testimony addresses four primary areas: revenue requirement, cost of service, base cost of gas and rate design.

Q. Please summarize your recommendations.

A. Rebuttal Schedule A-2, page 1 of 2, summarizes operating results at present and proposed rates for the 12 months ended December 31, 2004, the test year in this case. The present rates produced a net/total margin deficit, or loss, of $86,106 on an adjusted test year basis. The proposed $167,705 increase in revenues produces a positive net/total margin of $39,031 and a corresponding times interest earned ratio (TIER) of 2.00 in contrast to the current negative net TIER of 1.20.

DRSC accepts the Staff adjustments to its proposed rate base calculation as found on DTZ-3. DRSC is recommending the Staff proposed OCRB of $758,057 on DTZ-3 be adopted by the Commission in this case.

DRSC's Rebuttal Schedule C-1 shows the adjustments made to DRSC's test year revenues and expenses as a result of Staff's direct testimony.

Per Mr. Jack Shilling's rebuttal testimony, DRSC is recommending $600,000 of additional Long Term Debt ("LTD") be approved by the Commission. $502,000 of the $600,000 of additional LTD would be recovered through DRSC's recommended rebuttal rates. The $502,000 is the amount of current advances owed to Duncan Valley Electric Cooperative, Inc. ("DVEC"). This LTD would have a variable interest rate (assumed 5 percent) with repayment over 25 years.

DRSC stipulates to the testimony, recommendations and schedules as found in Mr. Prem Bahl's direct testimony.

DRSC agrees with the Staff testimony that recommends setting the base cost of gas to zero and in the future having the entire cost of gas be recovered from the fuel adjustor for the reasons stated in Staff's testimony.

With the exception of the per therm rates for each customer class and the interest rate on customer deposits as discussed in the Rate Design section of my rebuttal testimony, DRSC recommends that the rates and charges as shown on SPI-1, page 1 of 1.

DRSC is recommending the winter per therm rate be set at $0.73 and the summer per therm rate be set at $0.26 for all three customer classes. These per therm rates reflect DRSC's higher revenue requirement that has been recommended in its rebuttal testimony. Refer to Rebuttal Schedule H-3 for a comparison of present versus proposed rates. Refer to Rebuttal Schedules H-4 pages 1-3 for a typical bill analysis for the three customer classes.

DRSC is recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) that was approved in DVEC's recent rate case (Decision No. 67433, dated December 3, 2004).

Q. Do you view the indicated net TIER of 2.00 at proposed rates as a reasonable ratio in this case?

A. Yes. The 2.00 TIER requested in this case is, in my view, at the lower end of a reasonable TIER range for this utility in view of its negative equity, the need to reverse the losses it is experiencing most every month and the need to produce positive cash flows.

II. REVENUE REQUIREMENT

Rate Base

Q. Please comment on Staff's proposed rate base as illustrated on Schedule DTZ-3.

A. DRSC accepts the Staff adjustments to its proposed rate base calculation as found on DTZ-3. DRSC is recommending the Staff proposed OCRB of $758,057 on DTZ-3 be adopted by the Commission in this case.

Operating Income

Q. What are DRSC's recommended revenue, net/total margin and TIER amounts in its rebuttal testimony?

A. Rebuttal Schedule A-2, page 1 of 2, summarizes operating results at present and proposed rates for the 12 months ended December 31, 2004, the test year in this case. The present rates produced a net/total margin deficit, or loss, of $86,106 on an adjusted test year basis. The proposed $167,705 increase in revenues produces a positive net/total margin of

$39,031 and a corresponding times interest earned ratio (TIER) of 2.00 in contrast to the current negative net TIER of 1.20.

Q. Is DRSC recommending a higher revenue requirement and revenue increase in its rebuttal testimony versus its direct testimony?

A. Yes, it is. For the reasons stated in Mr. Jack Shilling's rebuttal testimony, DRSC is recommending a higher amount of additional LTD than it recommended in its direct testimony. As a result, the interest expense and margin amounts have increased from the levels recommended in DRSC's direct testimony.

Q. Does DRSC agree with Staff's revenue annualization adjustment of $2,574 (ADJ #1) shown on Schedule DTZ-7?

A. No, it does not. In order for this adjustment to be required, DRSC must experience a known and measurable growth in the number of customers in its customer classes. In order for this adjustment to be valid, DRSC must experience customer growth that is predictable, sustainable and significant. As a basis for making this adjustment, Staff has assumed that the number of customers in the 250 cfh and below class has increased from 740 in January 2004 to 747 in December 2004.

Q. Has DRSC experienced a predictable, sustainable and significant growth in its number of customers in 250 cfh and below class?

A. No, it has not. While it may appear from looking at Schedule DTZ-8, line 2 that the number of customers has increased from 740 in January 2004 to 747 in December 2004, the growth in the number of customers is not predictable, sustainable and significant. In fact the number of customers increases from 740 in January 2004 to approximately 747 in February and March but decreases back to 740 in April through June and further decreases to 729 in July and is approximately 735 in August and September and decreases to 730 in October and increases to 740 in November and 747 in December.

Q. Is this the type and pattern of monthly customer counts that is expected from a customer class that is experiencing predictable, sustainable and significant growth?

A. No it is not. In fact there appears to be little that is predictable about the number of customers in this class of customers or any of the other DRSC customer classes.

Q. Has Staff annualized the other two customer classes' revenues?

A. No, it has not. Staff did not annualize revenues for the Above 250 cfh to 425 cfh because of a large number of seasonal customers and did not annualize revenues for the Above 425 to 1,000 cfh class because this class experienced a customer decrease that was due to that customer moving to another class.

Q, Has DRSC experienced an increase in its total number of customers over the last five years?

A. As illustrated in Part R. of the annual RUS Form 7 reports that DRSC submitted with its direct testimony, DRSC has experienced a decline in its total number of customers.

Q. Does DRSC expect this trend to continue in the years 2005 and beyond?

A. Yes. As a result of a depressed local economy in Duncan's service territory and high natural gas prices, DRSC expects that its total number of customers will either continue to decline or remain stable in the future. I have attached the RUS Form 7 Report, Part R. that contains the number of customers by class for the months January through October of 2005. The number of customers in the 250 cfh and Above class decreases from 745 in January 2005 to 725 in October 2005.

Q. Should Staff's revenue annualization adjustment of $2,574 (ADJ #1) shown on Schedule DTZ-7 be adopted by the Commission?

A. No, it should not be adopted for the reasons stated above.

Q. Staff has recommended that DRSC remove the revenues and expenses associated with the ACC assessment charge and that these amounts should be recovered through a bill add-on. Does DRSC agree?

A. DRSC does not object to removing the revenues and expenses associated with the ACC assessment charge. As a result of the additional billing programming costs and a limited number of lines on its bill, DRSC does not agree that these amounts should be recovered through a bill add-on. DRSC proposes that this item be combined with another line item for recovery from customers.

Q. Please discuss Staff's adjustment to Interest Expense on Long Term Debt (LTD) of $8,019 (ADJ #6) shown on Schedule DTZ-7?

A. Staff has recommended that DRSC's additional LTD should be increased from $268,988 to $330,484. Staff has also decreased DRSC's proposed interest expense on the additional LTD from a variable annual rate of 6 percent to a variable rate of 2.725 percent, which is equal to Arizona Electric Power Cooperative's (AEPCO) current variable interest rate earned on funds that cooperatives have deposited with AEPCO.

Q. Given the Staff recommendations that DRSC discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative and meet a 30 percent equity ratio, what amount of additional LTD should be approved by in this case?

A. For the reasons stated in Jack Shilling's rebuttal testimony, DRSC is recommending additional LTD of $600,000 be approved for DRSC.

Q. What amount of interest expense is DRSC recommending by recovered in this case?

A. DRSC is recommending that $39,187 of interest expense be approved in this case. This interest expense amount is equal to the interest expense of $14,087 on existing LTD plus $25,100 (5.00 percent interest times $502,000 of advances from DVEC as of September 30, 2005). The interest expense on the outstanding amount of LTD of $98,000 ($600,000 of proposed LTD minus $502,000 of current DVEC advances) will be recovered from customers through the two phased-in rate increases of up to 5 percent that are discussed in Jack Shilling's rebuttal testimony.

Q. Does DRSC have concerns about Staff's recommendation to lower the interest rate from 6 to 2.725 percent?

A Yes, it does. Recently, interest rates have been gradually increasing. DRSC is concerned that interest rates will rise in the future above the current 2.725 rate. By setting this rate at the current rate of 2.725 percent, Staff has not allowed any margin for interest rate increases. If the Commission adopts the 2.725 percent interest rate and interest rates increase significantly, DRSC will need to spend more of its margins on interest expense and will have less to spend on capital improvements. In the past, expense increases have necessitated cash advances from Duncan Valley Electric Cooperative (DVEC).

Q. Is DRSC still recommending that the interest expense on LTD by set at 6 percent?

A. No, it is not. The 6 percent interest rate is a reasonable rate when compared with market interest rates for LTD, which would allow DRSC some cushion to be used for rising interest expense. However, as a compromise, DRSC recommends an interest rate of 5.00 percent be adopted.

Q. In its rebuttal testimony, has DRSC accepted Staff's adjustment to rate case expense of $4,851 (ADJ #4) shown on Schedule DTZ-7?

A. Yes. In its rebuttal testimony, DRSC has accepted Staff's adjustment to Rate Case Expense of $4,851 (ADJ #4) shown on Schedule DTZ-7. Staff's adjustment amortized DRSC's rate case expense over a three-year period rather than the two-year amortization recommended by DRSC. However, DRSC reserves the right to argue its position on this adjustment in rejoinder testimony if its rebuttal recommendations are not adopted by Staff. For the reasons set forth in Mr. Shilling's rebuttal testimony, DRSC may have to apply for rate increases annually to comply with the Staff recommendations on equity and advances from DVEC. Consequently amortizing the rate case over a three-year period as proposed by Staff, may not be appropriate in this case.

Q. Please explain the DRSC's Income Tax Expense for its proposed level of revenues and expenses as contained on Schedule A-2, page 2 of 2.

A. DRSC is a "C" Corporation and subject to federal and state income taxes. Based on the operating income level that results from DRSC's proposed rates in rebuttal testimony, DRSC will have an Income Tax Expense of approximately $17,722 as shown on Rebuttal Schedule A-2, page 2 of 2.

Q. Does DRSC have any other comments on the remaining adjustments on Schedule DTZ-7?

A. In its Rebuttal C-1 Schedule, DRSC has adopted the remaining adjustments found on Schedule DTZ-7. However, the test year and proposed income tax expense that DRSC is recommending is different from Staff's amounts due to the differences between DRSC's and Staff's revenue and expense levels.

III COST OF SERVICE, BASE COST OF GAS AND RATE DESIGN

Cost of Service Study

Q. Please comment on Mr. Prem Bahl's direct testimony regarding DRSC's cost of service study.

A. DRSC stipulates to the testimony, recommendations and schedules as found in Mr. Prem Bahl's direct testimony.

Base Cost of Gas

Q. Does DRSC agree with the Staff testimony that recommends setting the base cost of gas to zero and in the future having the entire cost of gas be recovered from the fuel adjustor?

A. Yes, it does for the reasons stated in Staff's testimony.

Rate Design

Q. Does DRSC agree with the Staff proposed rate design as shown on SPI-1, page 1 of 1?

A. Yes it does with the exception of the per therm rates for each customer class and the interest rate on customer deposits as discussed below.

Q. Does DRSC agree with the Staff proposed per therm rate design as shown on SPI-1, page 1 of 1?

A. No, it does not. The per therm rates shown on SPI-1 page 1 of 1 do not reflect a winter and summer cost differential and are different for each customer class.

Q. What is DRSC's proposal?

A. Mr. Prem Bahl has stated in his direct testimony that the largest plant account is distribution mains which is 67 percent of total distribution and that these mains have been allocated 100 percent on basis of demand. This has a direct impact on rate design.

DRSC's distribution system has been sized to meet its peak demands during the winter months. Consequently, the costs of providing service not only vary from summer to winter due to gas costs, there is a variance in DRSC's capacity/demand costs due to its peak winter season. For these reasons, DRSC is still proposing a higher winter per therm rate than the summer per therm rate.

Q. Do each of the customer's classes place a similar demand on the system during the five peak winter months?

A. No. The irrigation customers in the Above 250 cfh to 425 cfh class primarily uses gas during the off peak summer months. The Above 250 cfh to 425 cfh customers used 20,980 therms in the five peak winter months compared to 148,600 therms used by these customers in the other months. During the Test Year, DRSC's peak month for therm usage was February. In that month, irrigation customers used only 3,751 therms of the 83,019 therms sold to all DRSC customers.

Q. Does DRSC have any further recommendations regarding the per therm rates for each customer class?

A. Yes, it does. DRSC is also recommending that the summer and winter per therm rates be equal for all three classes. Besides the differences in the service line and meter that are recovered in the fixed monthly charge, the other distribution costs to serve the three customer classes are similar. Therefore, DRSC is recommending that the summer and winter per therm rates be equal for all three classes.

Q. What winter and summer per therm rates are you recommending for all three-customer classes?

A. DRSC is recommending the winter per therm rate be set at $0.73 and the summer per therm rate be set at $0.26 for all three customer classes. These per therm rates reflect

DRSC's higher revenue requirement that has been recommended in its rebuttal testimony. Refer to Rebuttal Schedule H-3 for a comparison of present versus proposed rates. Refer to Rebuttal Schedules H-4 pages 1-3 for a typical bill analysis for the three customer classes.

Q. Why is the winter per therm rate that DRSC is recommending significantly higher than the summer per therm rate?

A. During the Test Year, DRSC's customers' peak monthly usage was 83,019 therms in February versus 25,644 therms in lowest month, October. DRSC gas system is built to meet its peak demand (capacity) in the winter months like December, January and February. Customers who use the gas system during peak winter months should pay a higher share of the demand (capacity) related costs than customers who predominantly use gas during summer months.

Q. Please comment on Staff's proposal to raise the interest rate on customer deposits from 3 percent to 6 percent.

A. Staff is recommending that the interest rate on customer deposits be increased from 3 percent to 6 percent because all other gas utilities have a flat 6 percent interest rate on customer deposits.

Q. Is the current interest rate that DRSC earns on customer deposits equal to 6 percent?

A. No. It is equal to 2.78 percent.

Q. Should DRSC pay more interest on customer deposits than it is able to earn on its bank deposits?

A. No. It should not. Under Staff's recommendation DRSC will be paying customers with deposits 6 percent while currently only earning 2.78% on its deposits. The amount of interest paid on customer deposits that is exceeds what is earned by DRSC on its bank deposits or 3.22 percent (6.00% - 2.78%) is a subsidy paid to customers with deposits. This subsidy is paid by all of DRSC's customers without deposits.

Q. Does the variable interest rate proposed by DRSC better track the interest rate being earned by DRSC on its deposits?

A. Yes, it does. The variable interest rate proposed by DRSC will move up and down with market interest rates and will better reflect what DRSC is earning on its bank deposits.

Q. Should a flat 6 percent interest rate on customer deposits be adopted by the Commission for DRSC?

A. No, for the reasons stated above. DRSC's customers who do not have deposits should not be penalized because other gas utilities in the state have a 6 percent interest rate on customer deposits. DRSC is recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) that was approved in DVEC's recent rate case (Decision No. 67433, dated December 3, 2004).

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

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Rebuttal Schedule A-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST
1	Adjusted Operating Income (Loss)	$ (47,029)
2	Required Operating Income	$ 78,374
3	Operating Income Deficiency (L2 - L1)	$ 125,403
4	Gross Revenue Conversion Factor	1.32936
5	Increase In Gross Revenue (L3 * L4)	$ 166,705
6	Adjusted Test Year Revenue	$ 324,346
7	Proposed Annual Revenue (L5 + L6)	$ 491,051
8	Required Increase in Revenue (%) (L6/L7)*	51.40%

* This Required Increase in Revenue % does not include fuel adjustor revenues. The actual increase customers will experience is lower and is reflected on Typical Bill Analysis Schedules. Schedules H-4, pages 1-3.

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PROPOSED REVENUE INCREASE SUMMARY

Line No.	Description		Per Books		Test Year As Adjusted		Proposed Rates
1a.	Total Base Rate Revenue	$	644,167	$	319,136	$	485,841
1b.	Total Other Revenue*	$	5,210	$	5,210	$	5,210
1c.	Total Base Rate Revenue and Other Revenue	$	649,377	$	324,346	$	491,051
1d.	Plus: Fuel Adjustor Revenue	$	-	$	-	$	-
1e.	Total Revenue Before Other Contract Margin Revenue	$	649,377	$	324,346	$	491,051
1f.	Other Contract Margin Revenue	$	-	$	-	$	-
1g.	**Total Revenue**	**$**	**649,377**	**$**	**324,346**	**$**	**491,051**
2.	Operating Expense Before Interest Exp. On L.T. Debt	$	708,298	$	371,375	$	412,943
3.	Operating Margin Before Interest Exp. On L.T. Debt	$	(58,921)	$	(47,029)	$	78,108
4.	Interest Expense on Long-Term Debt	$	14,973	$	39,187	$	39,187
5.	Non-Operating Margins	$	110	$	110	$	110
6.	Total/Net Margin	$	(73,784)	$	(86,106)	$	39,031
7.	Total Long-Term Debt Principal Payment	$	45,305	$	55,421	$	55,421
8.	Net TIER (Intr Exp on L.T. Debt + Net Margin)/Total Intr Exp on L.T. Debt		(3.93)		(1.20)		2.00
9.	DSC (Net Margin + Depr Exp + Intr Exp on L.T. Debt)/ Prin&Int on L.T. Debt		(0.15)		(0.50)		1.35
10.	Rate Base	$	758,057	$	758,057	$	758,057
11.	% Return on Rate Base (Operating Margin / Rate Base)		-7.77%		-6.20%		10.30%
12.	**Total Proposed Revenue Increase Over Total Present Rates (Does not include Fuel Adjustor Revenue)**		-			**$**	**166,705**
14.	**% Increase In Total Adusted Test Year Revenues**						**25.66%**

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	SUMMARY OF FILING					
	PRESENT RATES				PROPOSED RATES	
Revenues		**Per Books**		**TY as Adjusted**		**Proposed**
Sales Revenue of Gas - Base Rates & PGA	$	644,167	$	319,136	$	485,841
Other Operating Revenue	$	5,210	$	5,210		5,210
Total Revenue	$	649,377		324,346	$	491,051
Expenses						
Purchased Gas	$	325,260	$	(0)	$	(0)
Distribution Expense - Operation	$	147,723	$	154,097	$	154,097
Distribution Expense - Maintenance	$	52,766	$	54,824	$	54,824
Consumer Accounts Expense	$	58,103	$	60,129	$	60,129
Administrative and General Expense	$	54,952	$	56,520	$	56,520
Depreciation and Amortization Expense	$	49,645	$	49,645	$	49,645
Tax Expense - Property	$	19,639	$	19,639	$	19,639
Tax Expense - Other	$	-	$	-	$	-
Tax Expense - Income taxes*	$	(158)	$	(23,846)	$	17,722
Interest Expense - Other	$	367	$	367	$	367
Total Operating Expenses	$	708,298	$	371,375	$	412,943
Interest Expense - Long-term Debt	$	14,973	$	39,187	$	39,187
Total Operating Expenses and Int on L.T. Debt	$	723,271	$	410,562	$	452,130
OPERATING MARGIN after Intr Exp on L.T. Debt	$	(73,894)	$	(86,216)	$	38,921
Non-Operating Margin						
Interest and Dividend Income	$	110	$	110	$	110
Capital Credits	$	-	$	-	$	-
	$	110	$	110	$	110
TOTAL/NET MARGINS	$	(73,784)	$	(86,106)	$	39,031

* For a calculation of Proposed Tax Expense-Income taxes, refer to
WORKPAPER FILENAME: DRSC Rebuttal ACC Schedules 11-19-05.xls, Worksheet: Schedule C-3

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Rebuttal Schedule C-1

		INCOME STATEMENT			
Acct. No.	**Revenues**	**Per Books**	**Adjustments**		**Adjusted TY**
480-481	Sales Revenue of Gas - Base Rates	$ 319,136	$ -	A	$ 319,136
451	Other Operating Revenue	$ 5,210	-		$ 5,210
	Total Revenue	$ 324,346	-		$ 324,346
Acct. No.	**Expenses**				
804.10	Gas Purchases	$ 325,260	(325,260.00)	F	$ (0)
	Distribution Expense - Operations				
870.00	Supervision	$ -	950	B	$ 950
874.00	Mains & Services	$ 105,889	4,137	B	$ 110,026
877.00	Measuring & Regulation Stations	$ 13,213	540	B	$ 13,753
878.00	Meters & House Regulators	$ 19,467	747	B	$ 20,214
880.00	Other Expenses	$ 3,116			$ 3,116
881.00	Rents	$ 6,039	-		$ 6,039
	Distribution Expense - Operations	$ 147,723	6,374		$ 154,097
	Distribution Expense - Maintenance				
885.00	Supervision	$ -			$ -
887.00	Mains & Services	$ 44,287	1,811	B	$ 46,098
891.00	Measuring & Regulation Stations	$ -			$ -
892.00	Services	$ -			$ -
893.00	Meters & House Regulators	$ 8,479	247	B	$ 8,726
894.00	Other Equipment	$ -			$ -
	Distribution Expense - Maintenance	$ 52,766	2,058		$ 54,824
	Consumer Accounts Expense				
902.00	Meter Reading Expense	$ 24,148	900	B	$ 25,048
903.00	Consumer Expense	$ 29,397	1,126	B	$ 30,523
904.00	Reserve for Uncollectible Accounts	$ 1,500	-		$ 1,500
909.00	Information & Instruction ads	$ 3,058	-		$ 3,058
	Consumer Accounts Expense	$ 58,103	2,026		$ 60,129
	Administrative and General Expense				
920.00	Salaries	$ 5,881	2,610	B	$ 8,491
921.00	Office Supplies and Expenses	$ 3,606	-		$ 3,606
923.00	Outside Services Employed	$ 11,826	-		$ 11,826
923.00	Rate Case	$ -	-		-
924.00	Property Insurance	$ -	-		$ -
925.00	Injuries and Damages Ins.	$ 17,568	-		$ 17,568
928.00	Regulatory Commission Expense	$ 10,521	(1,042)	C	$ 9,479
930.00	Miscellaneous General	$ 5,550	-		$ 5,550
		$ -	-		$ -
		$ -	-		$ -
		$ -	-		$ -
	Administrative and General Expense	$ 54,952	1,568		$ 56,520
	Interest Expense - Other				
		$ -	-		$ -
427.21	Interest Expense - Due to/Due from	$ -	-		$ -
431.00	Interest Expense - Customer Deposits	$ 367	-		$ 367
	Interest Expense - Other	$ 367	-		$ 367
403.00	Depreciation and Amortization Expense	$ 49,645	-		$ 49,645
408.00	Tax Expense - Property	$ 19,639			$ 19,639
408.50	Tax Expense - Other	$ -	-		$ -
409.00	Tax Expense - Income Taxes	$ (158)	(23,688)	D	$ (23,846)
	Total Expenses	$ 708,298	(336,922)		$ 371,375
	OPERATING MARGIN	$ (383,951)	336,922		$ (47,029)
427.10	Interest on Long Term Debt	$ 14,973	24,214	E	$ 39,187
428.00	Amortization of Debt Discount and Expense	$ -	-		$ -
	Total Interest Expense on LT Debt	$ 14,973	24,214		$ 39,187
	Non-Operating Margin				
419.00	Interest and Dividend Income	$ 110	-		$ 110
424.00	Capital Credits	$ -	-		$ -
		$ 110	-		$ 110
	TOTAL/NET MARGINS	$ (398,814)	$ 312,708		$ (86,106)

For the explanation to the income statement adjustments see Schedule C-2.

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Rebuttal Schedule C-2

EXPLANATION OF INCOME ADJUSTMENTS

A -	Sales Revenue of Gas	- Per Books	$	319,136		
		- Per Adjusted	$	319,136	$	-
	Reflects total revenues less base cost of gas and fuel adjustor revenue					
B -	Salaries & Related Expenses	- Per Books	$	135,525		
		- Per Adjusted	$	148,593	$	13,068
	To annualize salaries, salary increases and related benefits that occurred in the Test Year (WORKPAPER FILENAME: DRSC ACC Schedules 6-6-05.xls, Worksheet: SalaryAdj)					
C -	Regulatory Commission Expense	- Per Books	$	10,521		
		- Per Adjusted	$	9,479	$	(1,042)
	To reflect Staff's recommended rate case expense					
D -	Tax Expense - Income Taxes	- Per Books	$	(158)		
		- Per Adjusted	$	(23,846)	$	(23,688)
	To reflect the removal of a negative $158 loss carry-forward, a $50 income tax filing fee and Adjusted Test Year Income Tax Expense of a negative $23,580					
E -	Interest On Long-Term Debt	- Per Books	$	14,973		
		- Per Adjusted	$	39,187	$	24,214
	To reflect interest on additional Long-Term Debt of $ 502,000					
F -		- Per Books	$	325,260		
		- Per Adjusted	$	(0)	$	(325,260)
	To reflect the removal of purchased gas expense					

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Rebuttal Schedule H-3

RATE DESIGN

METER SIZES	Present Rates	Proposed Rates
250 cfh & Below		
Monthly Service Charge	$15.00	$20.00
Winter Commodity Rate per Therm	$0.44000	$0.73000
Summer Commodity Rate per Therm	$0.15405	$0.26000
Above 250 cfh to 425 cfh		
Monthly Service Charge	$22.50	$30.00
Winter Commodity Rate per Therm	$0.44000	$0.73000
Summer Commodity Rate per Therm	$0.15405	$0.26000
Above 425 cfh to 1,000 cfh		
Monthly Service Charge	$30.00	$40.00
Winter Commodity Rate per Therm	$0.44000	$0.73000
Summer Commodity Rate per Therm	$0.15405	$0.26000

Service Charges:	Present Rates	Proposed Rates
Establishment of Service (Regular Hours)	$ 35.00	$ 35.00
Establishment of Service (After Hours)	$ 50.00	$ 50.00
Re-establishment/Reconnectiion of Service (Regular Hours)	$ 50.00	$ 50.00
Re-establishment/Reconnection of Service (After Hours)	$ 75.00	$ 75.00
After Hours Service Calls - Consumer Caused (Per Hour)*	$ 50.00	$ 50.00
Meter Re-read Charge (No Charge for Read Error)	$ 30.00	$ 30.00
Meter Test Fee	$ 50.00	$ 50.00
Insufficient Funds Check	$ 20.00	$ 20.00
Interest Rate on Customer Deposits**	3.0%	Variable
Late/Deferred Payment (Per Month)	0.0%	1.5%

* One hour minimum
** Variable Rate based on the Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve

TYPICAL BILL ANALYSIS
250 cfh & Below

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Winter	76	$92.28	$119.45	$ 27.17	29.44%
Summer	20	$29.42	$36.53	$ 7.11	24.16%

Therm Consumption	Winter Present Rates*	Winter Proposed Rates	Winter % Change	Summer Present Rates*	Summer Proposed Rates	Summer % Change
0	$ 15.00	$ 20.00	33.33%	$ 15.00	$ 20.00	33.33%
25	$ 40.28	$ 52.53	30.42%	$ 33.13	$ 40.78	23.09%
50	$ 65.55	$ 85.05	29.75%	$ 51.25	$ 61.55	20.09%
60	$ 75.66	$ 98.06	29.61%	$ 58.50	$ 69.86	19.41%
70	$ 85.77	$ 111.07	29.50%	$ 65.75	$ 78.17	18.88%
75	$ 90.83	$ 117.58	29.45%	$ 69.38	$ 82.33	18.66%
80	$ 95.88	$ 124.08	29.41%	$ 73.00	$ 86.48	18.46%
90	$ 105.99	$ 137.09	29.34%	$ 80.25	$ 94.79	18.11%
100	$ 116.10	$ 150.10	29.29%	$ 87.51	$ 103.10	17.82%
125	$ 141.38	$ 182.63	29.18%	$ 105.63	$ 123.88	17.27%
150	$ 166.65	$ 215.15	29.10%	$ 123.76	$ 144.65	16.88%
175	$ 191.93	$ 247.68	29.05%	$ 141.88	$ 165.43	16.59%
200	$ 217.20	$ 280.20	29.01%	$ 160.01	$ 186.20	16.37%
250	$ 267.75	$ 345.25	28.94%	$ 196.26	$ 227.75	16.04%
300	$ 318.30	$ 410.30	28.90%	$ 232.52	$ 269.30	15.82%
350	$ 368.85	$ 475.35	28.87%	$ 268.77	$ 310.85	15.66%
400	$ 419.40	$ 540.40	28.85%	$ 305.02	$ 352.40	15.53%
450	$ 469.95	$ 605.45	28.83%	$ 341.27	$ 393.95	15.44%
500	$ 520.50	$ 670.50	28.82%	$ 377.53	$ 435.50	15.36%
750	$ 773.25	$ 995.75	28.77%	$ 558.79	$ 643.25	15.12%
1000	$ 1,026.00	$ 1,321.00	28.75%	$ 740.05	$ 851.00	14.99%

NOTE:
Fuel Adjustor Included in Present Rates $ 0.5710
Fuel Adjustor Included in Proposed Rates $ 0.5710

TYPICAL BILL ANALYSIS
Above 250 cfh to 425 cfh

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Winter	262	$287.63	$371.19	$ 83.55	29.05%
Summer	997	$745.60	$858.77	$ 113.17	15.18%

Irrigation

Therm Consumption	Winter Present Rates*	Winter Proposed Rates	Winter % Change	Summer Present Rates*	Summer Proposed Rates	Summer % Change
0	$ 22.50	$ 30.00	33.33%	$ 22.50	$ 30.00	33.33%
25	$ 47.78	$ 62.53	30.87%	$ 40.63	$ 50.78	24.98%
50	$ 73.05	$ 95.05	30.12%	$ 58.75	$ 71.55	21.78%
60	$ 83.16	$ 108.06	29.94%	$ 66.00	$ 79.86	20.99%
70	$ 93.27	$ 121.07	29.81%	$ 73.25	$ 88.17	20.36%
75	$ 98.33	$ 127.58	29.75%	$ 76.88	$ 92.33	20.09%
80	$ 103.38	$ 134.08	29.70%	$ 80.50	$ 96.48	19.84%
90	$ 113.49	$ 147.09	29.61%	$ 87.75	$ 104.79	19.41%
100	$ 123.60	$ 160.10	29.53%	$ 95.01	$ 113.10	19.05%
125	$ 148.88	$ 192.63	29.39%	$ 113.13	$ 133.88	18.34%
150	$ 174.15	$ 225.15	29.29%	$ 131.26	$ 154.65	17.82%
175	$ 199.43	$ 257.68	29.21%	$ 149.38	$ 175.43	17.43%
200	$ 224.70	$ 290.20	29.15%	$ 167.51	$ 196.20	17.13%
250	$ 275.25	$ 355.25	29.06%	$ 203.76	$ 237.75	16.68%
300	$ 325.80	$ 420.30	29.01%	$ 240.02	$ 279.30	16.37%
350	$ 376.35	$ 485.35	28.96%	$ 276.27	$ 320.85	16.14%
400	$ 426.90	$ 550.40	28.93%	$ 312.52	$ 362.40	15.96%
450	$ 477.45	$ 615.45	28.90%	$ 348.77	$ 403.95	15.82%
500	$ 528.00	$ 680.50	28.88%	$ 385.03	$ 445.50	15.71%
750	$ 780.75	$ 1,005.75	28.82%	$ 566.29	$ 653.25	15.36%
1000	$ 1,033.50	$ 1,331.00	28.79%	$ 747.55	$ 861.00	15.18%
1250	$ 1,286.25	$ 1,656.25	28.77%	$ 928.81	$ 1,068.75	15.07%
1500	$ 1,539.00	$ 1,981.50	28.75%	$ 1,110.08	$ 1,276.50	14.99%
1750	$ 1,791.75	$ 2,306.75	28.74%	$ 1,291.34	$ 1,484.25	14.94%
2000	$ 2,044.50	$ 2,632.00	28.74%	$ 1,472.60	$ 1,692.00	14.90%
2500	$ 2,550.00	$ 3,282.50	28.73%	$ 1,835.13	$ 2,107.50	14.84%
3000	$ 3,055.50	$ 3,933.00	28.72%	$ 2,197.65	$ 2,523.00	14.80%
4000	$ 4,066.50	$ 5,234.00	28.71%	$ 2,922.70	$ 3,354.00	14.76%
5000	$ 5,077.50	$ 6,535.00	28.71%	$ 3,647.75	$ 4,185.00	14.73%

NOTE:

Fuel Adjustor Included in Present Rates $ 0.5710
Fuel Adjustor Included in Proposed Rates $ 0.5710

TYPICAL BILL ANALYSIS
Above 425 cfh to 1,000 cfh

	Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
Winter	1,430	$1,475.73	$1,900.43	$ 424.70	28.78%
Summer	128	$122.81	$146.37	$ 23.56	19.19%

Therm Consumption	Winter Present Rates*	Winter Proposed Rates	Winter % Change	Summer Present Rates*	Summer Proposed Rates	Summer % Change
0	$ 30.00	$ 40.00	33.33%	$ 30.00	$ 40.00	33.33%
10	$ 40.11	$ 53.01	32.16%	$ 37.25	$ 48.31	29.69%
20	$ 50.22	$ 66.02	31.46%	$ 44.50	$ 56.62	27.23%
50	$ 80.55	$ 105.05	30.42%	$ 66.25	$ 81.55	23.09%
100	$ 131.10	$ 170.10	29.75%	$ 102.51	$ 123.10	20.09%
150	$ 181.65	$ 235.15	29.45%	$ 138.76	$ 164.65	18.66%
200	$ 232.20	$ 300.20	29.29%	$ 175.01	$ 206.20	17.82%
250	$ 282.75	$ 365.25	29.18%	$ 211.26	$ 247.75	17.27%
300	$ 333.30	$ 430.30	29.10%	$ 247.52	$ 289.30	16.88%
350	$ 383.85	$ 495.35	29.05%	$ 283.77	$ 330.85	16.59%
400	$ 434.40	$ 560.40	29.01%	$ 320.02	$ 372.40	16.37%
450	$ 484.95	$ 625.45	28.97%	$ 356.27	$ 413.95	16.19%
500	$ 535.50	$ 690.50	28.94%	$ 392.53	$ 455.50	16.04%
750	$ 788.25	$ 1,015.75	28.86%	$ 573.79	$ 663.25	15.59%
1000	$ 1,041.00	$ 1,341.00	28.82%	$ 755.05	$ 871.00	15.36%
1250	$ 1,293.75	$ 1,666.25	28.79%	$ 936.31	$ 1,078.75	15.21%
1500	$ 1,546.50	$ 1,991.50	28.77%	$ 1,117.58	$ 1,286.50	15.12%
1750	$ 1,799.25	$ 2,316.75	28.76%	$ 1,298.84	$ 1,494.25	15.05%
2000	$ 2,052.00	$ 2,642.00	28.75%	$ 1,480.10	$ 1,702.00	14.99%
2500	$ 2,557.50	$ 3,292.50	28.74%	$ 1,842.63	$ 2,117.50	14.92%
3000	$ 3,063.00	$ 3,943.00	28.73%	$ 2,205.15	$ 2,533.00	14.87%
3500	$ 3,568.50	$ 4,593.50	28.72%	$ 2,567.68	$ 2,948.50	14.83%
4000	$ 4,074.00	$ 5,244.00	28.72%	$ 2,930.20	$ 3,364.00	14.80%
4500	$ 4,579.50	$ 5,894.50	28.71%	$ 3,292.73	$ 3,779.50	14.78%
5000	$ 5,085.00	$ 6,545.00	28.71%	$ 3,655.25	$ 4,195.00	14.77%
5500	$ 5,590.50	$ 7,195.50	28.71%	$ 4,017.78	$ 4,610.50	14.75%
6000	$ 6,096.00	$ 7,846.00	28.71%	$ 4,380.30	$ 5,026.00	14.74%

NOTE:

Fuel Adjustor Included in Present Rates $ 0.5710

Fuel Adjustor Included in Proposed Rates $ 0.5710

DUNCAN RURAL SERVICES CORPORATION

FINANCIAL AND STATISTICAL REPORT	YEAR ENDING December 31, 2005

PART R. DATA BASE

CLASSIFICATION	SALES AND REVENUE	JANUARY (a)	FEBRUARY (b)	MARCH (c)	APRIL (d)	MAY (e)	JUNE (f)
1. Small	a. No. Served	745	741	732	740	734	734
	b. Therms Sold	67,736	58,274	39,910	30,924	16,210	13,564
	c. Revenue	79,331	70,024	51,368	33,980	23,067	21,063
2. Medium	a. No. Served	15	15	15	16	16	18
	b. Therms Sold	1,680	2,065	740	20,191	8,467	18,855
	c. Revenue	2,028	2,425	1,087	15,296	6,671	14,458
3. Large	a. No. Served	2	2	2	2	2	2
	b. Therms Sold	3,531	3,058	1,585	1,048	358	89
	c. Revenue	3,614	3,152	1,664	835	327	126
10. TOTAL No. Consumers (lines 1a-9a)		762	758	749	758	752	754
11. TOTAL Therms Sold (lines 1b-9b)		72,947	63,397	42,235	52,163	25,035	32,508
12. TOTAL Revenue Received From Sales of Energy (lines 1c-9c)		84,973	75,600	54,118	50,111	30,065	35,648
13. Other Gas Revenue		1,259	2,450	(3,976)	4,659	(437)	47
14. Own Use							
15. Total Gas Purchased (Therms)		76,290	55,750	39,030	45,430	19,980	31,100
16. Cost of Gas Purchased		42,459	34,019	19,965	34,390	14,006	18,782

DUNCAN RURAL SERVICES CORPORATION

FINANCIAL AND STATISTICAL REPORT	YEAR ENDING December 31, 2005

PART R. POWER REQUIREMENTS DATA BASE *(Continued)*

LINE ITEM NUMBER		JULY (g)	AUGUST (h)	SEPTEMBER (i)	OCTOBER (j)	NOVEMBER (k)	DECEMBER (l)	TOTAL (Columns a - l)
1	a.	726	727	724	725			
	b.	14,143	15,397	13,718	12,643			282,519
	c.	21,357	22,504	21,282	20,581			364,556
2	a.	19	18	19	18			
	b.	27,957	12,255	7,909	8,775			108,894
	c.	21,267	9,746	6,468	7,172			86,617
3	a.	2	2	2	2			20
	b.	70	94	119	194			10,146
	c.	112	131	151	209			10,321
10.		747	747	745	745	0	0	
11.		42,170	27,746	21,746	21,612	0	0	401,559
12.		42,736	32,380	27,901	27,962	0	0	461,494
13.		(619)	(682)	2,023	0	0	0	4,725
14.								0
15.		42,060	23,370	16,860				349,870
16.		28,410	15,579	14,835	0	0	0	222,445

EXHIBIT
A-3
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	DOCKET NO. G-02528A-03-0205

REJOINDER

TESTIMONY

OF

JOHN V. WALLACE

DUNCAN RURAL SERVICES CORPORATION

December 12, 2005

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name address and occupation.

A. My name is John V. Wallace. I am the Director of Regulatory and Strategic Services of Grand Canyon State Electric Cooperative Association (GCSECA). I represent Duncan Rural Services, Inc. (DRSC or the Company).

Q. Did you file direct and rebuttal testimony in this matter?

A. Yes.

Q. Was this testimony prepared by you or under your direction?

A. Yes, it was.

Q. What areas does your rebuttal testimony address?

A. My testimony addresses two primary areas: revenue requirement and rate design.

Q. Please summarize your recommendations.

A. Rebuttal Schedule A-2, page 1 of 2, summarizes operating results at present and proposed rates for the 12 months ended December 31, 2004, the test year in this case. The present rates produced a net/total margin deficit, or loss, of $86,106 on an adjusted test year basis. The proposed $167,705 increase in revenues produces a positive net/total margin of $39,031 and a corresponding times interest earned ratio (TIER) of 2.00 in contrast to the current negative net TIER of 1.20.

DRSC accepts the Staff adjustments to its proposed rate base calculation as found on DTZ-3. DRSC is recommending the Staff proposed OCRB of $758,057 on DTZ-3 be adopted by the Commission in this case.

DRSC's Rebuttal Schedule C-1 shows the adjustments made to DRSC's test year revenues and expenses as a result of Staff's direct testimony.

Per Mr. Jack Shilling's rebuttal testimony, DRSC is recommending $600,000 of additional Long Term Debt ("LTD") be approved by the Commission. $502,000 of the $600,000 of additional LTD would be recovered through DRSC's recommended rebuttal rates. The $502,000 is the amount of current advances owed to Duncan Valley Electric Cooperative, Inc. ("DVEC"). This LTD would have a variable interest rate (assumed 5 percent) with repayment over 25 years.

If the Commission does not adopt DRSC's recommended revenue requirement, DRSC recommends that the rate case expense be amortized over a 2 year period and Staff's adjustment to rate case expense of $4,851 (ADJ #4) shown on Schedule DTZ-7 be rejected.

DRSC stipulates to the testimony, recommendations and schedules as found in Mr. Prem Bahl's direct testimony.

DRSC agrees with the Staff testimony that recommends setting the base cost of gas to zero and in the future having the entire cost of gas be recovered from the fuel adjustor for the reasons stated in Staff's testimony.

However, DRSC recommends that the rates and charges as shown under the column entitled Company Proposed Rates on SPI-4, page 1 of 1, be approved.

DRSC is recommending the winter per therm rate be set at $0.73 and the summer per therm rate be set at $0.26 for all three customer classes. These per therm rates reflect

DRSC's higher revenue requirement that has been recommended in its rebuttal testimony. Refer to Rebuttal Schedules H-4 pages 1-3 for a typical bill analysis for the three customer classes.

DRSC is further recommending that the Commission reject Staff's recommendation for the Above 425 cfh to 1,000 cfh class to pay a significantly higher per therm rate than the other customer classes.

DRSC is recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) that was approved in DVEC's recent rate case (Decision No. 67433, dated December 3, 2004).

II. REVENUE REQUIREMENT

Operating Income

Q. Has DRSC's recommended revenue, net/total margin and TIER amounts as found in its rebuttal testimony changed as a result of Staff's surrebuttal testimony?

A. No. Rebuttal Schedule A-2, page 1 of 2, summarizes operating results at present and proposed rates for the 12 months ended December 31, 2004, the test year in this case. The present rates produced a net/total margin deficit, or loss, of $86,106 on an adjusted test year basis. The proposed $167,705 increase in revenues produces a positive net/total margin of $39,031 and a corresponding times interest earned ratio (TIER) of 2.00 in contrast to the current negative net TIER of 1.20.

Q. Please discuss Staff's adjustment to Interest Expense on Long Term Debt (LTD) of $8,019 (ADJ #6) shown on Schedule DTZ-7.

A. Staff has recommended that DRSC's additional LTD should be increased from $268,988 to $330,484. Staff has also decreased DRSC's proposed interest expense on the additional LTD from a variable annual rate of 6 percent to a variable rate of 2.725 percent which is equal to Arizona Electric Power Cooperative's (AEPCO) current variable interest rate earned on funds that cooperatives have deposited with AEPCO.

Q. Is the interest rate that DVEC is currently charging DRSC for advances equivalent to an interest rate that DVEC should charge on a LTD with a repayment period of 25 years?

A. No, it is not. DVEC is charging DRSC an interest rate on advances which is equal to AEPCO's current variable interest rate earned on funds that cooperatives have deposited with AEPCO. This interest rate is a deposit interest rate not a LTD interest rate.

Q. Is a deposit interest rate typically significantly lower than an interest rate on LTD with a term of 25 years?

A. Yes, it is. A lender has significantly more risk associated with a LTD that has a 25 year repayment period than with a short term deposit interest rate.

Q. Does the Staff recommendation to allow a variable rate of 2.725 percent which is equal to Arizona Electric Power Cooperative's (AEPCO) current variable interest rate earned on funds that cooperatives have deposited with AEPCO recognize this difference in risk?

A. No, it does not. Staff recommends the same interest rate for a 25 year LTD as DVEC earns on its deposits.

Q. In your rejoinder testimony, have you provided some evidence of this difference between interest rate for LTD versus deposits?

A. Yes, I have. I have attached to this testimony the current interest rates offered by National Rural Utilities Cooperative Finance Corporation (CFC). CFC's current variable interest rate for a loan with a 25 year term is 6.25 percent. I have also attached the Federal Reserve Statistical Release which demonstrates that the corporate bond interest rate for a corporation with a rating of Aaa is approximately 5.4 percent. A bond from a corporation with a rating of Baa is paying an interest rate approximately 6.36 percent.

Q. Given DRSC's financial condition, would it be eligible to borrow from a third party at any of these interest rates?

A. No. Even if it were able to borrow money from a third party, it would be borrowing at a significantly higher interest rate than the rates listed above.

Q. What amount of interest expense is DRSC recommending be recovered in this case?

A. DRSC is recommending that $39,187 of interest expense be approved in this case. This interest expense amount is equal to the interest expense of $14,087 on existing LTD plus $25,100 (5.00 percent interest times $502,000 of advances from DVEC as of September 30, 2005). The interest expense on the outstanding amount of LTD of $98,000 ($600,000 of proposed LTD minus $502,000 of current DVEC advances) will be recovered from customers through the two phased-in rate increases of 5 percent that are discussed in Jack Shilling's rebuttal testimony.

Q. In its rebuttal testimony, has DRSC accepted Staff's adjustment to rate case expense of $4,851 (ADJ #4) shown on Schedule DTZ-7?

A. Yes. In its rebuttal testimony, DRSC accepted Staff's adjustment to Rate Case Expense of $4,851 (ADJ #4) shown on Schedule DTZ-7. Staff's adjustment amortized DRSC's rate case expense over a three year period rather than the two year amortization recommended by DRSC. However, DRSC reserved the right to argue its position on this adjustment in rejoinder testimony if its rebuttal recommendations were not adopted.

Q. Has Staff adopted DRSC's rebuttal testimony recommendations?

A. No, it has not.

Q. In its rejoinder testimony, Is DRSC recommending that Staff's adjustment to rate case expense of $4,851 (ADJ #4) shown on Schedule DTZ-7 be adopted by the Commission?

A. No, it is not. For the reasons set forth in Mr. Shilling's rebuttal testimony, DRSC may have to apply for rate increases annually to comply with the Staff recommendations on equity and advances from DVEC. Consequently amortizing the rate case over a three year period as proposed by Staff is not appropriate in this case. If the Commission does not adopt DRSC's recommended revenue requirement, DRSC recommends that the rate case expense be amortized over a 2 year period and Staff's adjustment to rate case expense of $4,851 (ADJ #4) shown on Schedule DTZ-7 be rejected.

III RATE DESIGN

Q. Does DRSC agree with the Staff proposed rate design as shown on its surrebuttal SPI-4, page 1 of 1?

A. No it does not. DRSC recommends that the rates and charges as shown under the column entitled Company Proposed Rates on SPI-4, page 1 of 1, be approved.

Q. Does DRSC agree with the Staff proposed per therm rate design as shown on SPI-4, page 1 of 1?

A. No, it does not. The per therm rates shown on SPI-4 page 1 of 1 do not reflect a winter and summer cost differential and are different for each customer class.

Q. Does DRSC's per therm rate design reflect a winter and summer cost differential?

A. Yes, it does. DRSC's distribution system has been sized to meet its peak demands during the winter months. Consequently, the costs of providing service not only vary from summer to winter due to gas costs, there is a variance in DRSC's capacity/demand costs due to its peak winter season. For these reasons, DRSC is still proposing a higher winter per therm rate than the summer per therm rate as found on rebuttal Schedule H-3.

Q. Do each of the customer's classes place a similar demand on the system during the five peak winter months?

A. No. As stated previously, the irrigation customers in the Above 250 cfh to 425 cfh class primarily use gas during the off peak summer months. The Above 250 cfh to 425 cfh customers used 20,980 therms in the five peak winter months compared to 148,600 therms used by these customers in the other months. During the Test Year, DRSC's peak month for therm usage was February. In that month, irrigation customers used only 3,751 therms of the 83,019 therms sold to all DRSC customers.

Q. What are the potential impacts to DRSC if Staff's per therm rate design is adopted by the Commission?

A. The irrigation customers in the Above 250 cfh to 425 cfh class are price sensitive and will convert their pumps to electric power or decide not to pump any water. If this occurs, then DRSC will lose all of the revenue from these irrigation customers which will result in higher rates for DRSC's remaining customers. The Staff recommended per therm rate design may also encourage irrigation customers to use gas in winter months which would result in DRSC having to increase its capacity to meet this new demand. This would make DRSC's capital budget even higher than the $80,000 that is projected.

Q. Staff has stated concerns in its testimony about cost shifting among customers. Will Staff's per therm rate design result in cost shifting?

A. Yes, it will. It shifts costs from winter peak customers to irrigation customers who may leave DRSC's system. It also shifts significantly higher costs to the Above 425 cfh to 1,000 cfh class.

Q. What customers are currently taking service under the Above 425 cfh to 1,000 cfh tariff?

A. The school district is currently the only customer taking service under the Above 425 cfh to 1,000 cfh tariff.

Q. Does DRSC have concerns about Staff's rate design which significantly increases the per therm rates that the school will pay?

A. Yes, it does. The distribution costs that are not related to capacity/demand for the three customer classes are similar. Consequently, it is unfair to the school district to pay a significantly higher per therm rate than DRSC's other customer classes. In addition, rates paid by schools are ultimately paid by DRSC's customers through taxes. Finally, equal per therm rates for all customer classes are easier to explain to customers and to administer. For these reasons, DRSC is recommending that the summer and winter per therm rates be equal for all three classes. DRSC is further recommending that the Commission reject Staff's recommendation for the Above 425 cfh to 1,000 cfh class to pay a significantly higher per therm rate than the other customer classes.

Q. Does DRSC have a recommendation on how Staff's per therm rate could be modified to achieve Staff's surrebuttal revenue requirement without significantly increasing the per therm rates that the school will pay?

A. Yes, it does. Under the Staff proposed rate design methodology, the winter and summer per therm rates could be set at $0.5808 for the Above 425 cfh to 1,000 cfh class and the Below 250 cfh class. The Above 250 cfh to 425 cfh summer and winter per therm rates would remain at $0.2848 as stated in Staff's Schedule SPI-4.

Q. What winter and summer per therm rates are you recommending for all three customer classes?

A. DRSC is recommending the winter per therm rate be set at $0.73 and the summer per therm rate be set at $0.26 for all three customer classes. Refer to rebuttal Schedule H-3 for a comparison of present versus proposed rates. Refer to rebuttal Schedules H-4 pages 1-3 for a typical bill analysis for the three customer classes.

Q. Why is the winter per therm rate that DRSC is recommending significantly higher than the summer per therm rate?

A. During the Test Year, DRSC's customers' peak monthly usage was 83,019 therms in February versus 25,644 therms in lowest month, October. DRSC gas system is built to meet its peak demand (capacity) in the winter months like December, January and February. Customers who use the gas system during peak winter months should pay a higher share of the demand (capacity) related costs than customers who predominantly use gas during summer months.

Q. In its surrebuttal testimony, is Staff still recommending that the interest rate on customer deposits be increased from 3 percent to 6 percent?

A. Yes, it is. Staff is recommending that the interest rate on customer deposits be increased from 3 percent to 6 percent because all other gas utilities have a flat 6 percent interest rate on customer deposits.

Q. In its rejoinder testimony, is DRSC still recommending the same interest rate on customer deposits be adopted as it recommended in its rebuttal testimony?

A. Yes, it is for the reasons stated in my rebuttal testimony. In addition, DRSC does not believe it is fair for its gas customers to pay a higher interest rate on deposits than DVEC's customers must pay. DRSC is recommending that the Commission approve the same interest rate on customer deposits (Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve) that was approved in DVEC's recent rate case (Decision No. 67433, dated December 3, 2004).

Q. Does that conclude your rejoinder testimony?

A. Yes, it does.

POWERFUL FINANCIAL SOLUTIONS

December 1, 2005

Interest Rates

LONG-TERM FIXED RATES FOR 12/1/05

1 year	6.300%
20 year	6.750%
30 year	6.850%

SHORT-TERM RATES EFFECTIVE 12/1/05

Long-Term Variable Rate	6.250%
Line of Credit/Intermediate	6.100%
Associate Member (5% Loan CTCs)	6.550%
Associate Member (10% Loan CTCs)	6.250%

BANK PRIME RATE ON 12/1/05

7.000%

RUS MUNICIPAL LOAN RATES

Rates for October 1, 2005 – December 31, 2005

YEAR INTEREST TERM ENDS	INTEREST RATE	YEAR INTEREST TERM ENDS	INTEREST RATE
2006	2.875%	2016	3.750%
2007	3.000%	2017	3.875%
2008	3.125%	2018	3.875%
2009	3.125%	2019	3.875%
2010	3.250%	2020	4.000%
2011	3.375%	2021	4.000%
2012	3.500%	2022	4.000%
2013	3.500%	2023	4.125%
2014	3.625%	2024	4.125%
2015	3.750%	2025	4.125%
		2026 or later	4.250%

CFC COMMERCIAL PAPER RATES FOR 12/1/05

DAYS	RATE	DAYS	RATE
1-5	4.075%	37-119	4.425%
6-14	4.100%	120-149	4.475%
15-18	4.150%	150-179	4.525%
19-28	4.300%	180-209	4.600%
29-36	4.125%	210-270	4.625%

To invest in CFC CP call: 800-424-2955

CFC MEDIUM-TERM NOTES FOR 12/1/05

MONTHS	RATE	MONTHS	RATE
10	4.870%	18	4.900%
11	4.880%	19	4.900%
12	4.890%	20	4.900%
13	4.890%	21	4.910%
14	4.890%	22	4.910%
15	4.900%	23	4.910%
16	4.900%	24	4.910%
17	4.900%		

To invest in CFC MTNs call: 800-424-2954, ext. 6731

NOTICE

Fixed Rates for Class A members are quoted each business day. These rates are for selected maturities and are available for loans advanced or repriced today. These rates do not include discounts. Call the CFC Rate Line at 800-599-6782 or visit CFC's website http:\\www.nrucfc.org for rate quotes, for other maturity periods, and for rate information any time during the month. Variable rates are subject to change monthly or semi-monthly in accordance with the terms of the loan agreement.

Quoted Associate Member rates reflect the value of the different CTC investments related to the two loan types.

POWERFUL FINANCIAL SOLUTIONS

December 1, 2005

Investment Rates

The Fed:

As expected on November 1, the Federal Open Market Committee (FOMC) unanimously voted to increase the federal funds rate for the twelfth consecutive time by another 25 basis points to reach a new target rate of 4 percent. The minutes from the FOMC November meeting indicate that Fed members continue to view the U.S. economy growing at a strong pace, albeit a temporary, regional negative impact from the hurricanes. Despite recent favorable inflation data, the FOMC remains concerned about the upside risk to the inflation outlook. The Committee also acknowledged the need to alter its policy statement "before long," and discussed the statement's potential evolution to place a greater dependence of future policy changes on both economic and inflationary developments. Keeping the Fed statement appropriate to current market conditions is a necessary element of the Fed's credibility. In addition, the minutes revealed that the current target rate of 4 percent is within the lower area of some members' neutral range, and the FOMC must be wary of tightening monetary policy too soon or too quickly. The fed funds futures market is still fully pricing in another 25 basis point rate hike at the next FOMC meeting on December 13. Looking further out, the futures market is currently pricing in a 85 percent chance of another rate increase at the FOMC meeting on January 31.

THE ECONOMY:

According to the Bureau of Economic Analysis (BEA) preliminary estimate, GDP rose at a 4.3 percent annual rate during the third quarter, stronger growth than the consensus estimate of 4.0 percent and higher than the previous advance estimate of 3.8 percent. The increase was driven by many components including consumer spending on nondurable goods, housing investment, and business investment. These upward revisions more than offset the upward revision to imports. The U.S. economy continued to push ahead, brushing off the impact of Hurricanes Katrina and Rita. Overall, inflation gauges for the third quarter experienced sharp increases, however core inflation remains low. The government's price index for personal consumption (PCE) rose 3.6%. The PCE core deflator, excluding food and energy rose 1.2% in the third quarter, down from 0.1% from the prior advance estimate.

CFC COMMERCIAL PAPER RATES

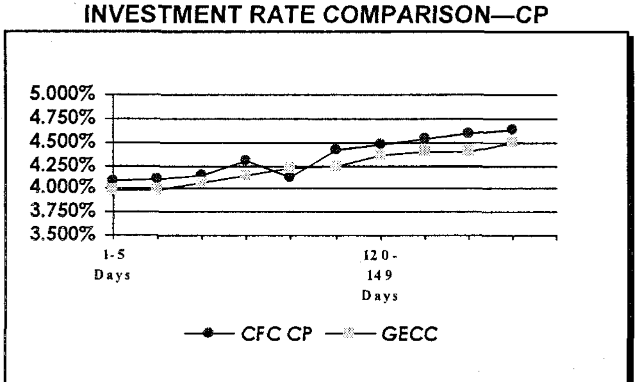
# OF DAYS	CURRENT RATES	90-DAY HISTORY AVERAGE	HIGH	LOW
1-5	4.075%	3.730%	4.075%	3.250%
6-14	4.100%	3.759%	4.100%	3.325%
15-20	4.150%	3.795%	4.150%	3.325%
21-58	4.300%	3.855%	4.300%	3.450%
59-66	4.125%	3.890%	4.125%	3.575%
67-119	4.425%	4.034%	4.425%	3.675%
120-149	4.475%	4.102%	4.475%	3.750%
150-179	4.525%	4.168%	4.525%	3.825%
180-209	4.600%	4.232%	4.600%	3.875%
210-270	4.625%	4.277%	4.650%	3.900%

Spread between CFC 9-month CP & 10-month MTN:0.25%
Spread between CFC 2-year MTN & 1-year MTN:0.02%

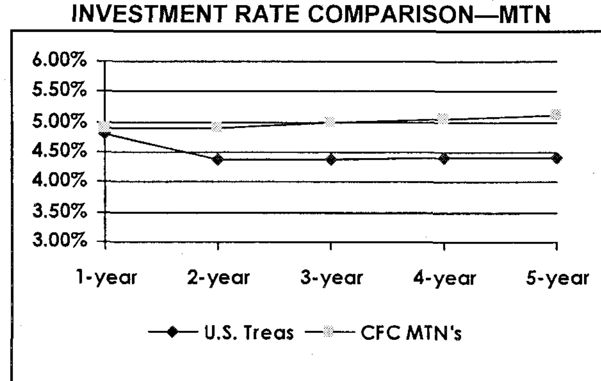
CFC MEDIUM-TERM NOTE RATES

# OF MONTHS	CURRENT RATES	90-DAY HISTORY AVERAGE	HIGH	LOW
10	4.87%	4.52%	4.89%	4.06%
11	4.88%	4.53%	4.90%	4.07%
12	4.89%	4.54%	4.91%	4.08%
13	4.89%	4.55%	4.92%	4.09%
14	4.89%	4.56%	4.92%	4.10%
15	4.90%	4.57%	4.93%	4.11%
16	4.90%	4.58%	4.94%	4.12%
17	4.90%	4.59%	4.95%	4.12%
18	4.90%	4.60%	4.95%	4.13%
19	4.90%	4.60%	4.96%	4.14%
20	4.90%	4.61%	4.97%	4.15%
21	4.91%	4.62%	4.97%	4.16%
22	4.91%	4.63%	4.98%	4.17%
23	4.91%	4.64%	4.99%	4.18%
24	4.91%	4.65%	5.00%	4.19%

INVESTMENT RATE COMPARISON—CP



INVESTMENT RATE COMPARISON—MTN



Note: Stated rates are indicative only. Call (800) 424-2955 for current CFC Commercial Paper Rates and (800) 424-2954 ext. 731 for current CFC Medium-Term Note Rates

Federal Reserve Statistical Release

H.15

Selected Interest Rates

Release Date: December 5, 2005

Release dates | Daily update | Historical data | About

Current release *Other formats:* Screen reader | ASCII | PDF (17 KB)

FEDERAL RESERVE STATISTICAL RELEASE

H.15 (519) SELECTED INTEREST RATES
For use at 2:30 p.m. Eastern Time

Yields in percent per annum December 5, 2005

Instruments	2005 Nov 28	2005 Nov 29	2005 Nov 30	2005 Dec 1	2005 Dec 2	Wee Dec 2
Federal funds (effective) 1 2 3	4.01	3.99	4.03	4.03	4.00	4.0
Commercial Paper 3 4 5						
Nonfinancial						
1-month	4.11	4.07	4.11	4.13	4.18	4.1
2-month	n.a.	n.a.	n.a.	n.a.	n.a.	n.a
3-month	n.a.	n.a.	n.a.	n.a.	n.a.	n.a
Financial						
1-month	4.10	4.13	4.15	4.12	4.17	4.1
2-month	4.23	4.25	4.25	4.26	4.28	4.2
3-month	4.28	4.30	4.29	4.29	4.32	4.3
CDs (secondary market) 3 6						
1-month	4.18	4.25	4.25	4.27	4.28	4.2
3-month	4.37	4.37	4.38	4.40	4.42	4.3
6-month	4.54	4.54	4.55	4.59	4.61	4.5
Eurodollar deposits (London) 3 7						
1-month	4.22	4.27	4.28	4.29	4.29	4.2
3-month	4.39	4.40	4.41	4.41	4.44	4.4
6-month	4.57	4.57	4.59	4.61	4.63	4.5
Bank prime loan 2 3 8	7.00	7.00	7.00	7.00	7.00	7.0
Discount window primary credit 2 9	5.00	5.00	5.00	5.00	5.00	5.0
U.S. government securities						
Treasury bills (secondary market) 3 4						
4-week	3.88	3.92	3.93	3.93	3.94	3.9
3-month	3.89	3.89	3.86	3.88	3.90	3.8
6-month	4.16	4.17	4.16	4.17	4.16	4.1
Treasury constant maturities						
Nominal 10						
1-month	3.94	3.99	4.00	3.99	4.00	3.9
3-month	3.98	3.98	3.95	3.97	3.99	3.9
6-month	4.31	4.32	4.31	4.32	4.31	4.3
1-year	4.32	4.35	4.34	4.36	4.35	4.3
2-year	4.33	4.40	4.42	4.45	4.43	4.4
3-year	4.32	4.40	4.41	4.44	4.43	4.4
5-year	4.32	4.40	4.42	4.45	4.45	4.4
7-year	4.35	4.42	4.45	4.47	4.48	4.4
10-year	4.41	4.48	4.49	4.52	4.52	4.4

20-year 11	4.71	4.78	4.81	4.83	4.81	4.7
Inflation indexed 12						
5-year	1.94	2.03	2.07	2.08	2.09	2.0
7-year	2.00	2.08	2.10	2.12	2.13	2.0
10-year	2.04	2.11	2.12	2.15	2.16	2.1
20-year	2.13	2.18	2.17	2.21	2.21	2.1
Inflation-indexed long-term average 13	2.08	2.14	2.13	2.16	2.17	2.1
Interest rate swaps 14						
1-year	4.75	4.79	4.80	4.83	4.85	4.8
2-year	4.75	4.80	4.82	4.87	4.89	4.8
3-year	4.77	4.82	4.85	4.89	4.91	4.8
4-year	4.79	4.85	4.88	4.92	4.95	4.8
5-year	4.82	4.88	4.91	4.95	4.98	4.9
7-year	4.87	4.92	4.96	4.99	5.03	4.9
10-year	4.94	5.00	5.03	5.06	5.10	5.0
30-year	5.14	5.20	5.23	5.25	5.28	5.2
Corporate bonds						
Moody's seasoned						
Aaa 15	5.30	5.37	5.42	5.45	5.44	5.4
Baa	6.30	6.36	6.38	6.39	6.39	6.3
State & local bonds 16				4.53		4.5
Conventional mortgages 17				6.26		6.2

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on broke

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the curr figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settl Depository Trust Company. The trades represent sales of commercial paper by deale issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. An average of dealer bid rates on nationally traded certificates of deposit.

7. Bid rates for Eurodollar deposits collected around 9:30 a.m. Eastern time.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U. commercial banks. Prime is one of several base rates used by banks to price short loans.

9. The rate charged for discounts made and advances extended under the Federal Re credit discount window program, which became effective January 9, 2003. This rate adjustment credit, which was discontinued after January 8, 2003. For further info www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate for the Federal Reserve Bank of New York. Historical series for the rate on adjus well as the rate on primary credit are available at www.federalreserve.gov/releas

10. Yields on actively traded non-inflation-indexed issues adjusted to constant m

EXHIBIT
A-4
12-15-05
Admitted

Duncan Rural Services Corporation
Docket No. G-02528A-05-0314
Test Year Ended December 31, 2004

Rejoinder Schedule A-2
Page 1 of 2

PROPOSED REVENUE INCREASE
SUMMARY

Line No.	Description	Per Books	Test Year As Adjusted	Proposed Rates	Proposed Rates With 5% Inc.	Proposed Rates With 10% Inc.
1a.	Total Base Rate Revenue	$ 644,167	$ 319,136	$ 485,841	$ 502,060	$ 518,278
1b.	Total Other Revenue*	$ 5,210	$ 5,210	$ 5,210	$ 5,210	$ 5,210
1c.	Total Base Rate Revenue and Other Revenue	$ 649,377	$ 324,346	$ 491,051	$ 507,270	$ 523,488
1d.	Plus: Fuel Adjustor Revenue	$ -	$ -	$ -	$ -	$ -
1e.	Total Revenue Before Other Contract Margin Revenue	$ 649,377	$ 324,346	$ 491,051	$ 507,270	$ 523,488
1f.	Other Contract Margin Revenue	$ -	$ -	$ -	$ -	$ -
1g.	**Total Revenue**	**$ 649,377**	**$ 324,346**	**$ 491,051**	**$ 507,270**	**$ 523,488**
2.	Operating Expense Before Interest Exp. On L.T. Debt	$ 708,298	$ 371,375	$ 412,943	$ 412,943	$ 420,713
3.	Operating Margin Before Interest Exp. On L.T. Debt	$ (58,921)	$ (47,029)	$ 78,108	$ 94,326	$ 102,774
4.	Interest Expense on Long-Term Debt	$ 14,973	$ 39,187	$ 39,187	$ 39,187	$ 39,187
5.	Non-Operating Margins	$ 110	$ 110	$ 110	$ 110	$ 110
6.	Total/Net Margin	$ (73,784)	$ (86,106)	$ 39,031	$ 55,249	$ 63,697
7.	Total Long-Term Debt Principal Payment	$ 45,305	$ 55,421	$ 55,421	$ 55,421	$ 55,421
8.	Net TIER (Intr Exp on L.T. Debt + Net Margin)/Total Intr Exp on L.T. Debt	(3.93)	(1.20)	2.00	2.41	2.63
9.	DSC (Net Margin + Depr Exp + Intr Exp on L.T. Debt)/ Prin&Int on L.T. Debt	(0.15)	(0.50)	1.35	1.52	1.61
10.	Rate Base	$ 758,057	$ 758,057	$ 758,057	$ 758,057	$ 758,057
11.	% Return on Rate Base (Operating Margin / Rate Base)	-7.77%	-6.20%	10.30%	12.44%	13.56%
12.	**Total Proposed Revenue Increase Over Total Present Rates (Does not include Fuel Adjustor Revenue)**	-		**$ 166,705**	**$ 182,923**	**$ 199,142**
14.	**% Increase In Total Adusted Test Year Revenues**			**25.66%**	**28.16%**	**30.66%**
15.	**Increase In Revenues**				**$ 16,218**	**$ 32,436**

Duncan Rural Services Corporation
Docket No. G-02528A-05-0314
Test Year Ended December 31, 2004

	SUMMARY OF FILING				
	PRESENT RATES		PROPOSED RATES		
Revenues	**Per Books**	**TY as Adjusted**	**Proposed**	**Proposed With 5 %**	**Proposed With 10 %**
Sales Revenue of Gas - Base Rates & PGA	$ 644,167	$ 319,136	$ 485,841	$ 502,060	$ 518,278
Other Operating Revenue	$ 5,210	$ 5,210	5,210	5,210	5,210
Total Revenue	$ 649,377	324,346	$ 491,051	$ 507,270	$ 523,488
Expenses					
Purchased Gas	$ 325,260	$ (0)	$ (0)	$ (0)	$ (0)
Distribution Expense - Operation	$ 147,723	$ 154,097	$ 154,097	$ 154,097	$ 154,097
Distribution Expense - Maintenance	$ 52,766	$ 54,824	$ 54,824	$ 54,824	$ 54,824
Consumer Accounts Expense	$ 58,103	$ 60,129	$ 60,129	$ 60,129	$ 60,129
Administrative and General Expense	$ 54,952	$ 56,520	$ 56,520	$ 56,520	$ 56,520
Depreciation and Amortization Expense	$ 49,645	$ 49,645	$ 49,645	$ 49,645	$ 49,645
Tax Expense - Property	$ 19,639	$ 19,639	$ 19,639	$ 19,639	$ 19,639
Tax Expense - Other	$ -	$ -	$ -	$ -	$ -
Tax Expense - Income taxes*	$ (158)	$ (23,846)	$ 17,722	$ 21,474	$ 25,492
Interest Expense - Other	$ 367	$ 367	$ 367	$ 367	$ 367
Total Operating Expenses	$ 708,298	$ 371,375	$ 412,943	$ 416,695	$ 420,713
Interest Expense - Long-term Debt	$ 14,973	$ 39,187	$ 39,187	$ 39,187	$ 39,187
Total Operating Expenses and Int on L.T. Debt	$ 723,271	$ 410,562	$ 452,130	$ 455,882	$ 459,900
OPERATING MARGIN after Intr Exp on L.T. Debt	$ (73,894)	$ (86,216)	$ 38,921	$ 51,387	$ 63,587
Non-Operating Margin					
Interest and Dividend Income	$ 110	$ 110	$ 110	$ 110	$ 110
Capital Credits	$ -	$ -	$ -	$ -	$ -
	$ 110	$ 110	$ 110	$ 110	$ 110
TOTAL/NET MARGINS	$ (73,784)	$ (86,106)	$ 39,031	$ 51,497	$ 63,697

EXHIBIT A-5 12-15-05 Admitted

Duncan Rural Services Corporation
Docket No. G-02528A-05-0314
Test Year Ended December 31, 2004

Rejoinder Schedule H-3

RATE DESIGN

METER SIZES	Present Rates	Proposed Rates	Proposed Rates With 5% Incr.	Proposed Rates With 10% Incr.
250 cfh & Below				
Monthly Service Charge	$15.00	$20.00	$20.00	$20.00
Winter Commodity Rate per Therm	$0.44000	$0.73000	$0.77000	$0.81000
Summer Commodity Rate per Therm	$0.15405	$0.26000	$0.27600	$0.28800
Above 250 cfh to 425 cfh				
Monthly Service Charge	$22.50	$30.00	$30.00	$30.00
Winter Commodity Rate per Therm	$0.44000	$0.73000	$0.77000	$0.81000
Summer Commodity Rate per Therm	$0.15405	$0.26000	$0.27600	$0.28800
Above 425 cfh to 1,000 cfh				
Monthly Service Charge	$30.00	$40.00	$40.00	$40.00
Winter Commodity Rate per Therm	$0.44000	$0.73000	$0.77000	$0.81000
Summer Commodity Rate per Therm	$0.15405	$0.26000	$0.27600	$0.28800

Service Charges:	Present Rates	Proposed Rates	Proposed Rates	Proposed Rates
Establishment of Service (Regular Hours)	$ 35.00	$ 35.00	$ 35.00	$ 35.00
Establishment of Service (After Hours)	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Re-establishment/Reconnectiion of Service (Regular Hours)	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Re-establishment/Reconnection of Service (After Hours)	$ 75.00	$ 75.00	$ 75.00	$ 75.00
After Hours Service Calls - Consumer Caused (Per Hour)*	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Meter Re-read Charge (No Charge for Read Error)	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Meter Test Fee	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Insufficient Funds Check	$ 20.00	$ 20.00	$ 20.00	$ 20.00
Interest Rate on Customer Deposits**	3.0%	Variable	Variable	Variable
Late/Deferred Payment (Per Month)	0.0%	1.5%	1.5%	1.5%

* One hour minimum
** Variable Rate based on the Three Month Non-Financial Commercial Paper Rate as published by the Federal Reserve

Base Cost of Gas & Fuel Adjustor Included in Present Rates	$	-
Base Cost of Gas $ Fuel Adjustor Included in Proposed Rates	$	-

EXHIBIT
A-6
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	DOCKET NO. G-02528A-03-0205

DIRECT

TESTIMONY

OF

JACK SHILLING

CHIEF EXECUTIVE OFFICER
DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.

June 9, 2005

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, address and occupation.

A. My name is Jack Shilling. My business address is 222 Highway 75, P.O. Box 440, Duncan, Arizona. I am Chief Executive Officer of Duncan Valley Electric Cooperative, Inc. ("DVEC"). Through an Operations and Management Agreement, Duncan Valley manages the day-to-day operations of Duncan Rural Services Corporation ("DRSC").

Q. Please describe the nature of DRSC's Operations.

A. DRSC is a non-profit corporation that provides service to about 760 consumers in Greenlee County. The gas system was acquired in 1989 from General Utilities, Inc. ("General"). The vast majority of DRSC's consumers are rural, residential users that heat their homes with natural gas. Approximately 56% of the utility's annual sales occur during the five winter months of November through March.

II. REVENUE REQUIREMENTS

Q. Please summarize DRSC's rate request in this proceeding.

A. We are requesting Commission approval to increase our overall revenues by 22.70%. The proposed rates contained in the filing schedules are designed to provide additional annual revenues of $147,406. In the test year ending December 31, 2004, DRSC sustained an adjusted net/total margin loss of slightly less than $78,000.

A detailed discussion of all aspects of the request is provided in the testimony of Mr. John Wallace, Director of Regulatory and Strategic Services for Grand Canyon State Electric Cooperative Association.

Q. When did DRSC last increase its rates?

A. In Decision No. 64869 (June 5, 2002), the Commission authorized a 24 percent increase in gross annual revenues based on a test year ending December 31, 2000. In this case, the Commission found that DRSC had suffered a net loss in the test year of approximately $19,000.

In Decision No. 59539, dated February 21, 1996, the Commission authorized a 31% increase in gross annual revenues based on a test year ending December 31, 1994. In the 1995 case, the Commission found that DRSC had suffered an adjusted $52,508 operating margin loss in the test year.

Q. Has DRSC's financial position improved in years after its most recent rate case?

A. Not significantly. Given the fact that DRSC has a lower number of customers now approximately 760 versus 820 customers in the last rate case, DRSC's capital requirements of approximately $55,000 to $108,000 per year and the increases in purchased gas and other expenses, DRSC's revenues have not kept pace with its costs. As DRSC's audited financial statements indicate, DRSC's total margins have declined from a negative $18,859 on December 31, 2003 to a negative $49,639 on December 31, 2004.

Q. What are the reasons why DRSC's financial performance has not improved?

A. There are two primary reasons. First, DRSC's customer base is decreasing not growing, which allows expenses to outpace revenues. Second, as mentioned above, purchased gas costs have significantly increased during the Test Year and other costs have increased since DRSC's last rate case.

III. CAPITAL IMPROVEMENTS & FINANCING

Q. Please describe the major capital improvements DRSC has made to the system since its acquisition in late 1989.

A. As the Commission found in Decision No. 58356, General's system at time of purchase was in serious disrepair and had been cited numerous times by the Staff's pipeline safety section. DRSC's efforts have been primarily directed to bringing the system into substantial safety compliance and also reducing large system gas losses. In consultation with the pipeline safety section, a meter replacement program was begun in 1993. Of course, normal repairs, replacements and additions to the system have also been necessary over the past fifteen years. The major construction project remaining is the PVC pipe replacement project, which also was discussed at pages 18-19 of Decision No. 58356. In compliance with that Decision, a finance application was filed with the Commission to fund that project on April 19, 1995 that was approved in Decision No. 59271, (September 20, 1995). Since that time, DRSC has been replacing pipe and making repairs in its gas distribution system that have resulted in a significant reduction in the number of gas leaks.

Since its last rate case with a Test Year ended of December 31, 2000, DRSC has made the following plant additions by year:

2001 - $108,087

2002 - $106,194

2003 - $62,393

2004 - $54,620

According to DRSC's financial forecast, capital additions will continue to average approximately $80,000 for the next five years.

Q. How have the costs of these projects been met?

A. DRSC was completely debt funded at its inception. As of December 31, 2004, DRSC had negative equity of approximately $150,000. Therefore, other than cash available from depreciation (a non-cash expense), there have been no funds available from DRSC to meet these construction needs. Duncan Valley manages the operations of DRSC including its operational and capital expenditures and then keeps track of these expenditures on a company-by-company basis. As of March 2004, the account payable from DRSC to DVEC had grown to approximately $455,000. This obviously is not a satisfactory long-term situation for the members of either DRSC or DVEC.

Q. Please explain how DRSC proposes to address and remedy this situation.

A. As discussed further in the financing section of Mr. Wallaces's direct testimony, DRSC plans to borrow $268,988 from Duncan Valley for completed construction and correspondingly will reduce DRSC's account payable to DVEC. An adjustment to reflect interest and principal charges associated with the debt has been made in the schedules Mr. Wallace has prepared. The rates requested in this proceeding would then allow DRSC to meet these obligations and provide some positive margins on a going forward basis.

Q. Has DRSC previously requested approval of this $268,988 of additional debt?

A. Yes. On April 4, 2003, DRSC filed an application that requested that a loan in the amount of $400,000 be approved by the Commission (Docket No. G-02528A-03-0205). Shortly after making this filing, DRSC requested that Commission Staff not process this case until it filed a rate case. DRSC made this request because it would not be able to repay this additional debt without a rate increase. DRSC had originally intended to file its rate case in 2004 with a Test Year ending December 31, 2003. However, due to the amount of man hours needed to complete a rate case for DVEC in Arizona and New Mexico, the DRSC rate case application was not able to be completed until April of 2005.

DRSC is requesting that the financing application (Docket No. G-02528A-03-0205) be consolidated with this rate case docket for the reasons stated above.

Q. Can DVEC continue to advance funds to DRSC at the levels it has in previous years.

A. No. DVEC can not continue to advance funds to DRSC in the amounts that it has in previous years. DVEC's cash account has been significantly reduced due to DRSC's advances and the amounts borrowed. DVEC can no longer sustain this level of advances. DRSC must be financially self-sufficient and must stop relying on the funds of DVEC.

Q. Have DVEC and DRSC considered other measures to address these financial concerns?

A. Yes. The DVEC and DRSC Board of Directors have considered reorganizing DRSC such that DRSC would become a department/division of DVEC as well as other alternatives to address DRSC's financial situation. If DRSC would become a department/division of DVEC, this would allow DRSC access to CFC's low cost financing and restore DRSC's non-taxable status. However, there are many other factors (i.e. income tax issues, debt issues, regulatory approvals, etc.) that must be considered and resolved before any reorganization is approved and can occur.

Q. Does such reorganization completely address the financial concerns of DRSC?

A. No. DRSC will still need to be financially responsible for all expenses, debt service and construction expenditures that it incurs. Consequently, the first step is to improve DRSC's financial condition by increasing rates to a level that interest and debt coverage ratios will be acceptable to outside lenders and where enough cash-flow is being provided through rates to fund expenses, debt payments and construction without the continued need for advances from outside sources.

Q. If DRSC's proposed revenue increase is granted, will DRSC be on the road to financial recovery?

A. Yes. According to DRSC's financial forecast, if DRSC's proposed increase is granted, DRSC will be in the financial position to pay its expenses, debt service and fund the majority of its construction without having to rely on major advances from DVEC (Please refer to the schedule entitled Financial Forecast that is attached to this testimony). Also according to this financial forecast, DRSC should remain in this financial position for the next several years.

Q. Does that conclude your direct testimony?

A. Yes, it does.

FINANCIAL FORECAST FORM 325A - FINANCIAL RATIOS

ITEM	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. EQUITY RATIO (WITH ADD REVENUE) (%)	-10.27%	-11.28%	-16.31%	-22.96%	-32.11%	-22.54%	-16.83%	-12.54%	-9.54%	-7.91%	-7.76%	-5.91%	-4.13%
2. DSC (WITH ADD REVENUE)	1.36	0.88	0.34	0.14	-0.16	2.93	2.60	2.41	2.20	1.94	1.64	1.95	1.94
3. TIER (WITH ADD REVENUE)	0.04	-0.52	-2.24	-2.69	-3.23	4.15	3.51	3.04	2.51	1.84	1.04	2.00	2.00
4. AVERAGE REV PER THERM SOLD (DOLLARS)	0.82	0.98	1.13	1.15	1.15	1.42	1.42	1.42	1.42	1.42	1.42	1.47	1.49
5. INCREASE IN AVER REV PER THERM SOLD (%)	XXX	19.19%	15.02%	1.90%	0.03%	23.31%	0.00%	0.01%	-0.01%	-0.01%	-0.01%	3.87%	1.41%
6. TOT UTIL PLANT PER THERM SOLD (DOLLARS)	2.01	1.99	2.30	2.42	2.55	2.69	2.83	2.97	3.11	3.24	3.38	3.52	3.66
7. NET GENER FUNDS TO TOT UTIL PLANT (%)	0.80%	0.40%	0.41%	-1.89%	-5.05%	0.00%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8. ACCUM DEPR & AMORT TO TOT UTIL PLANT (%)	42.53%	43.42%	45.17%	46.09%	47.10%	48.19%	49.34%	50.54%	51.80%	53.09%	54.43%	55.79%	57.19%
9. OPER & MAIN COST PER CONSUMER ($)	189.79	234.22	263.80	250.28	258.74	266.57	273.77	282.60	291.01	299.00	309.14	319.07	326.01
10.ADMIN & GENER EXP PER CONSUMER ($)	48.68	59.23	72.31	71.77	73.93	75.87	79.76	81.39	82.81	86.49	90.17	91.16	94.74
11.PLANT REVENUE RATIO	4.21	3.96	4.07	4.34	4.58	3.26	3.43	3.60	3.76	3.93	4.10	4.00	4.06
TE OF RETURN ON RATE BASE (%)	0.65%	-2.30%	-7.78%	-5.63%	-6.98%	10.29%	8.49%	6.88%	5.39%	3.81%	2.12%	4.11%	4.02%
TEBASE = 104% OF NET UTIL PLANT	710,517	743,539	752,960	785,183	814,494	840,893	864,380	884,954	902,617	917,368	929,207	938,134	944,149
14.% INCR OVER PRESENT RATES REQ	XXX	XXX	XXX	XXX	0.03%	0.02%	0.02%	0.03%	0.02%	0.01%	0.00%	3.88%	5.34%
15.MODIFIED DSC	1.52	0.65	-0.19	0.14	-0.16	2.93	2.60	2.41	2.20	1.94	1.64	1.95	1.94
16.MOD. TIER	0.20	-1.37	-3.81	-2.69	-3.23	4.15	3.51	3.04	2.51	1.84	1.04	2.00	2.00

FINANCIAL FORECAST FORM 325B - BALANCE SHEET

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. ASSETS AND OTHER DEBITS													
A. TOTAL UTILITY PLANT	1,188,833	1,263,675	1,320,470	1,400,470	1,480,470	1,560,470	1,640,470	1,720,470	1,800,470	1,880,470	1,960,470	2,040,470	2,120,470
B. ACCUM DEPR AND AMORT	505,644	548,734	596,470	645,486	697,303	751,919	809,336	869,552	932,569	998,385	1,067,002	1,138,418	1,212,635
C. NET UTILITY PLANT	683,189	714,941	724,000	754,984	783,167	808,551	831,134	850,918	867,901	882,085	893,468	902,052	907,836
D. NET GENERAL FUNDS	9,564	5,094	5,458	(26,456)	(74,800)	0	656	0	0	0	0	0	0
E. GENERAL FUNDS EXCLUDABLE ITEMS	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
F. OTHER ASSETS AND DEBITS	80,731	151,813	177,511	177,511	177,511	177,511	177,511	177,511	177,511	177,511	177,511	177,511	177,511
G. TOTAL ASSETS AND OTHER DEBITS	774,484	872,848	907,969	907,039	886,878	987,062	1,010,301	1,029,429	1,046,412	1,060,596	1,071,979	1,080,563	1,086,347
2. LIABILITIES AND OTHER CREDITS													
A. TOTAL MARGINS AND EQUITIES	(79,574)	(98,435)	(148,072)	(208,298)	(284,808)	(222,507)	(170,012)	(129,136)	(99,866)	(83,893)	(83,134)	(63,853)	(44,893)
B. LONG TERM DEBT													
C. LONG TERM DEBT- OTHER	608,229	562,263	516,958	576,253	632,604	670,486	641,230	619,482	607,195	605,405	616,030	605,333	592,157
D. OTHER LIABILITIES AND CREDITS	245,829	409,020	539,083	539,083	539,083	539,083	539,083	539,083	539,083	539,083	539,083	539,083	539,083
E. TOTAL LIABILITIES AND CREDITS	774,484	872,848	907,969	907,039	886,878	987,062	1,010,301	1,029,429	1,046,412	1,060,596	1,071,979	1,080,563	1,086,347

FINANCIAL FORECAST FORM 325C - STATEMENT OF OPERATIONS

ITEM	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. ACCRUAL BASIS													
A1.ADD REV REQ'D TO MEET TIER GOALS	0	0	0	0	168	169	132	234	176	70	2	31,843	43,882
A2.OPER REV & PAT CAP (PRESENT RATES)	486,060	622,515	649,378	667,119	667,119	822,640	822,640	822,640	822,640	822,640	822,640	822,640	822,640
B. COST OF GAS	203,481	303,644	325,260	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388
C. OPER REV LESS COST OF GAS	282,579	318,871	324,118	322,731	322,899	478,421	478,383	478,486	478,427	478,322	478,254	510,095	522,133
EXPENSES LESS COST OF GAS	301,395	348,332	398,011	383,284	397,822	411,632	425,888	437,650	449,157	462,348	477,495	490,814	503,173
D. OPER & MAIN EXPENSE	150,310	180,119	200,490	190,464	196,903	202,861	208,340	215,059	221,458	227,537	235,256	242,816	248,095
E. CONSUMER ACC & SALES EXPENSE	47,702	45,826	58,103	53,270	54,031	54,792	55,553	56,314	57,075	57,836	58,597	59,358	60,119
F. ADM & GEN & OTHER DEDUCTIONS EXPENSE	38,557	45,546	54,952	54,618	56,258	57,737	60,697	61,937	63,016	65,816	68,616	69,376	72,096
G. DEPRECIATION & AMORT EXPENSE	29,340	46,807	49,645	49,016	51,816	54,616	57,416	60,216	63,016	65,816	68,616	71,416	74,216
H. TAX EXPENSE	12,048	17,642	19,481	19,607	20,727	21,847	22,967	24,087	25,207	26,327	27,447	28,567	29,687
I. INTEREST EXPENSE	23,438	12,392	15,340	16,309	18,088	19,778	20,915	20,037	19,384	19,016	18,962	19,281	18,960
J. TOTAL COST OF GAS SERVICE	504,876	651,976	723,271	727,672	742,210	756,020	770,276	782,038	793,545	806,736	821,883	835,202	847,561
K PATRONAGE CAPITAL & OPER MARGINS	(18,816)	(29,461)	(73,893)	(60,553)	(74,923)	66,789	52,496	40,836	29,271	15,973	758	19,281	18,960
ƆNOPERATING MARGINS	51	110	110	327	(1,587)	(4,488)	0	39	0	0	0	0	0
)THER EXTRORDINARY ITEMS	(3,658)	10,490	24,146										
... TOTAL ACCRUAL MARGINS	(22,423)	(18,861)	(49,637)	(60,226)	(76,511)	62,301	52,496	40,875	29,271	15,973	758	19,281	18,960
GOAL: TIER	XXX	XXX	XXX	XXX	-3.23	4.15	3.51	3.04	2.51	1.84	1.04	2.00	2.00
2. CASH BASIS													
A. CASH BEFORE DEBT SERVICE	34,013	29,848	(8,798)	5,099	(6,606)	136,696	130,827	121,129	111,671	100,806	88,337	109,978	112,136
B. TOTAL DEBT SERVICE	22,362	45,966	45,305	37,013	41,737	46,602	50,318	50,327	50,818	51,917	53,704	56,310	57,822
C. CASH MARGINS AFTER DEBT SERVICE	11,651	(16,118)	(54,103)	(31,914)	(48,344)	90,093	80,508	70,801	60,854	48,888	34,633	53,669	54,315

FINANCIAL FORECAST FORM 325D - GENERAL FUNDS SUMMARY

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. SOURCES OF GENERAL FUNDS													
A. NET GENERAL FUNDS (FIRST OF YEAR)	XXX	XXX	XXX	5,458	(26,456)	(74,800)	0	656	0	0	0	0	0
B. CASH MARGINS AFTER DEBT SERVICE	XXX	XXX	XXX	(31,914)	(48,344)	90,093	80,508	70,801	60,854	48,888	34,633	53,669	54,315
C. OTHER PROCEEDS	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
D	XXX	XXX	XXX										
EIMBURSEMENTS	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
IEIMBURSEMENTS FROM SPECIAL LOANS	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
2. I OTAL GENERAL FUNDS AVAILABLE	XXX	XXX	XXX	(26,456)	(74,800)	15,293	80,508	71,457	60,854	48,888	34,633	53,669	54,315
3. PROPOSED USES OF GENERAL FUNDS													
A.	XXX	XXX	XXX										
B. CAPITAL CREDIT RETIREMENTS	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
C. GEN FUNDS INVESTED IN PLANT	XXX	XXX	XXX	0	0	15,293	79,852	71,457	60,854	48,888	34,633	53,669	54,315
D. OTHER USES OF GENERAL FUNDS	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
4. TOTAL PROPOSED USES OF GENERAL FUNDS	XXX	XXX	XXX	0	0	15,293	79,852	71,457	60,854	48,888	34,633	53,669	54,315
5. NET GENERAL FUNDS(END OF YEAR)	9,564	5,094	5,458	(26,456)	(74,800)	0	656	0	0	0	0	0	0
GENERAL FUNDS GOAL - PERCENTAGE	XXX	XXX	XXX	0.00%	0.00%	0.00%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GEN FUNDS REQUIRED FOR PLANT INVEST	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
ADDL GEN FUNDS AVAIL FOR PLANT INVEST	XXX	XXX	XXX	0	0	15,293	79,852	71,457	60,854	48,888	34,633	53,669	54,315

FINANCIAL FORECAST FORM 325E - DETERMINATION OF LOAD

ITEM	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. NUMBER OF CONSUMERS													
A. 250 chf and below	766	746	739	740	740	740	740	740	740	740	740	740	740
B.	0	0	0	0	0	0	0	0	0	0	0	0	0
C. 256 chf and 425 chf	24	20	19	19	19	19	19	19	19	19	19	19	19
D. 426 chf and 1000 chf	2	3	2	2	2	2	2	2	2	2	2	2	2
K. TOTAL CONSUMERS	792	769	760	761	761	761	761	761	761	761	761	761	761
2. AVERAGE MONTHLY USE PER CONSUMER													
A. 250 chf and below	41	44	44	44	44	44	44	44	44	44	44	44	44
B.	#DIV/0!	#DIV/0!	#DIV/0!	0	0	0	0	0	0	0	0	0	0
C. 251 chf and 425 chf	576	863	746	750	750	750	750	750	750	750	750	750	750
D. 426 chf and 1000 chf	2,000	1,028	750	750	750	750	750	750	750	750	750	750	750
NUAL SALES (THERMS)													
50 chf and below	376	390	387	391	391	391	391	391	391	391	391	391	391
	0	0	0	0	0	0	0	0	0	0	0	0	0
C. 251 chf and 425 chf	166	207	170	171	171	171	171	171	171	171	171	171	171
D. 426 chf and 1000 chf	48	37	18	18	18	18	18	18	18	18	18	18	18
4. ANNUAL GAS REQUIREMENTS													
A. TOTAL THERMS SOLD	590	634	575	580	580	580	580	580	580	580	580	580	580
A1.THERMS SOLD NOT SUBJECT TO LINE LOSS	0	0	0	0	0	0	0	0	0	0	0	0	0
B. SYSTEMS OWN USE	0	0	0	0	0	0	0	0	0	0	0	0	0
C. SYSTEM LOSS PERCENTAGE	-0.042403	-0.070946	-0.043557	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000	-0.010000
D. THERMS REQUIREMENTS	566	592	551	574	574	574	574	574	574	574	574	574	574

FINANCIAL FORECAST FORM 325F - DETERMINATION OF OPERATII PAGE 1 OF 2

ITEM	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
3. BY "REV PER THERM SOLD METHOD"	CONSUMER CLASS ---------->			250 chf and below									
A. TOTAL ANNUAL THERMS SOLD	376	390	387	391	391	391	391	391	391	391	391	391	391
B. AVERAGE REVENUE PER THERM SOLD	0.68336	0.76546	0.86602	0.95765	0.95765	1.18000	1.18000	1.18000	1.18000	1.18000	1.18000	1.18000	1.18000
C. FIXED MONTHLY CHARGE PER CONS	14.00	15.00	15.00	15.00	15.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
D. AVG NUMBER OF CONSUMERS	766	746	739	740	740	740	740	740	740	740	740	740	740
E. ANNUAL REV LESS FLOWTHRU ADJ	385,631	432,810	468,170	507,373	507,373	638,650	638,650	638,650	638,650	638,650	638,650	638,650	638,650
3. BY "REV PER THERM SOLD METHOD"	CONSUMER CLASS ---------->												
A. TOTAL ANNUAL THERMS SOLD	0	0	0	0	0	0	0	0	0	0	0	0	0
B. AVERAGE REVENUE PER THERM SOLD	#DIV/0!	#DIV/0!	#DIV/0!	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C. FIXED MONTHLY CHARGE PER CONS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D. AVG NUMBER OF CONSUMERS	0	0	0	0	0	0	0	0	0	0	0	0	0
F ANNUAL REV LESS FLOWTHRU ADJ	0	0	0	0	0	0	0	0	0	0	0	0	0
"REV PER THERM SOLD METHOD"	CONSUMER CLASS ---------->			251 chf and 425 chf									
.. TOTAL ANNUAL THERMS SOLD	166	207	170	171	171	171	171	171	171	171	171	171	171
B. AVERAGE REVENUE PER THERM SOLD	0.50646	0.62451	0.68653	0.78564	0.78564	0.89000	0.89000	0.89000	0.89000	0.89000	0.89000	0.89000	0.89000
C. FIXED MONTHLY CHARGE PER CONS	20.00	22.50	22.50	22.50	22.50	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
D. AVG NUMBER OF CONSUMERS	24	20	19	19	19	19	19	19	19	19	19	19	19
E. ANNUAL REV LESS FLOWTHRU ADJ	89,833	134,674	121,840	139,474	139,474	159,030	159,030	159,030	159,030	159,030	159,030	159,030	159,030
3. BY "REV PER THERM SOLD METHOD"	CONSUMER CLASS ---------->			426 chf and 1000 chf									
A. TOTAL ANNUAL THERMS SOLD	48	37	18	18	18	18	18	18	18	18	18	18	18
B. AVERAGE REVENUE PER THERM SOLD	0.76096	0.68946	0.89089	1.00286	1.00286	1.25000	1.25000	1.25000	1.25000	1.25000	1.25000	1.25000	1.25000
C. FIXED MONTHLY CHARGE PER CONS	25.00	30.00	30.00	30.00	30.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
D. AVG NUMBER OF CONSUMERS	2	3	2	2	2	2	2	2	2	2	2	2	2
E. ANNUAL REV LESS FLOWTHRU ADJ	37,126	26,590	16,756	18,771	18,771	23,460	23,460	23,460	23,460	23,460	23,460	23,460	23,460
4. FLOWTHRU ADJUSTMENTS													
A. THERMS SOLD SUBJECT TO ADJ- 1	590	634	575	580	580	580	580	580	580	580	580	580	580
B. FLOWTHRU ADJ- 1 PER THERM	0	0	0	0	0	0	0	0	0	0	0	0	0
C. REV FROM ADJUSTMENT- 1	0	0	0	0	0	0	0	0	0	0	0	0	0
D. THERMS SOLD SUBJECT TO ADJ- 2	0	0	0	0	0	0	0	0	0	0	0	0	0
F FLOWTHRU ADJ- 2 PER THERM	0	0	0	0	0	0	0	0	0	0	0	0	0
REV FROM ADJUSTMENT- 2	0	0	0	0	0	0	0	0	0	0	0	0	0
. TOTAL REV FROM ADJUSTMENTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5. TOTAL REV FROM SALE OF GAS ENERGY	512,590	594,074	606,766	665,619	665,619	821,140	821,140	821,140	821,140	821,140	821,140	821,140	821,140
6. OTHER OPERATING REVENUE	(26,530)	28,441	42,612	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
7. TOTAL OPERATING REVENUE	486,060	622,515	649,378	667,119	667,119	822,640	822,640	822,640	822,640	822,640	822,640	822,640	822,640

FINANCIAL FORECAST FORM 325G - DETERMINATION OF PLANT INVESTMENT & LOAN REQUIREMENTS

ITEM	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. A. TOTAL UTILITY PLANT (BEGIN YEAR)	748,893	1,188,833	1,263,675	1,320,470	1,400,470	1,480,470	1,560,470	1,640,470	1,720,470	1,800,470	1,880,470	1,960,470	2,040,470
B. PLANT ADDITIONS AND REPLACEMENTS	439,940	74,842	56,795	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
C. CONTRIBUTIONS IN AID OF CONST.	0	0	0	0	0	0	0	0	0	0	0	0	0
D. RETIREMENTS	0	0	0	0	0	0	0	0	0	0	0	0	0
E. TOTAL UTILITY PLANT (END OF YEAR)	1,188,833	1,263,675	1,320,470	1,400,470	1,480,470	1,560,470	1,640,470	1,720,470	1,800,470	1,880,470	1,960,470	2,040,470	2,120,470
2. ANALYSIS OF PRIORITY FUNDS.													
A. DISTR.- NEW CONSTRUCTION	439,940	74,842	56,795	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
B. DISTR.- SYSTEM IMPROVEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
C. DISTR.- ORDINARY REPLACEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
D. DISTR.- SUBTRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
F. DISTR.- WAREHOUSE, ETC.	0	0	0	0	0	0	0	0	0	0	0	0	0
EIMBURSEMENT OF GENERAL FUNDS	0	0	0	0	0	0	0	0	0	0	0	0	0
OTAL OF PRIORITY ITEMS.	439,940	74,842	56,795	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
SS: H. CONTR. IN AID OF CONST.	0	0	0	0	0	0	0	0	0	0	0	0	0
I. GEN. FUNDS INVESTED IN PLANT	0	0	0	0	0	15,293	79,852	71,457	60,854	48,888	34,633	53,669	54,315
J. LOAN FUNDS REQD FOR PRIORITY ITEMS	XXX	XXX	XXX	80,000	80,000	64,707	148	8,543	19,146	31,112	45,367	26,331	25,685
K. PRIOR LOAN FUNDS REQUIRED	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
N. NEW LOANS FROM OTHER SOURCES	XXX	XXX	XXX	80,000	80,000	64,707	148	8,543	19,146	31,112	45,367	26,331	25,685
3. ANALYSIS OF NON-PRIORITY FUNDS													
A. OFFICE HEADQUARTERS	0	0	0	0	0	0	0	0	0	0	0	0	0
B. GENERAL PLANT ADDITIONS	0	0	0	0	0	0	0	0	0	0	0	0	0
C. GENERATION AND TRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
D. OTHER NEEDS (E. G. SCADA)	0	0	0	0	0	0	0	0	0	0	0	0	0
E. TOTAL NON-PRIORITY FUNDS REQ.	0	0	0	0	0	0	0	0	0	0	0	0	0
LESS: F. SPECIAL LOAN FUNDS USED	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
G. GEN. FUNDS INVESTED IN PLANT	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
H. LOAN FUNDS REQ.--OTHER	XXX	XXX	XXX	0	0	0	0	0	0	0	0	0	0
4. TOTAL NEW LOANS REQ. FROM OTHERS	XXX	XXX	XXX	80,000	80,000	64,707	148	8,543	19,146	31,112	45,367	26,331	25,685
TEREST RATE ON LOANS	3.00%												
EXISTING LOAN FUNDS AVAILABLE:													
AMOUNT	0			0	0	0	0	0	0	0	0	0	0

FINANCIAL FORECAST FORM 325I - SUPPLEMENTAL DEBT SERVICE

	2002	2003 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
SUPPLEMENTAL LOANS												
1. A. DATE OF LOAN		ADVANCE	0	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	630,591	E. BAL 1ST OF YEAR	516,958	496,253	474,927	452,962	430,337	407,034	383,031	358,309	332,844	306,616
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	15,509	14,888	14,248	13,589	12,910	12,211	11,491	10,749	9,985	9,198
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	36,213	36,213	36,213	36,213	36,213	36,213	36,213	36,213	36,213	36,213
TYPE:		H. BAL END OF YEAR	496,253	474,927	452,962	430,337	407,034	383,031	358,309	332,844	306,616	279,601
2. A. DATE OF LOAN	2005	ADVANCE	80,000	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	80,000	E. BAL 1ST OF YEAR	0	80,000	77,676	75,283	72,817	70,278	67,663	64,969	62,194	59,336
C. AMORTIZATION PERIOD	24	F. PLUS: INTEREST	0	2,400	2,330	2,258	2,185	2,108	2,030	1,949	1,866	1,780
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	4,724	4,724	4,724	4,724	4,724	4,724	4,724	4,724	4,724
TYPE:		H. BAL END OF YEAR	80,000	77,676	75,283	72,817	70,278	67,663	64,969	62,194	59,336	56,392
DATE OF LOAN	2006	ADVANCE	0	80,000	0	0	0	0	0	0	0	0
MOUNT OF LOAN	80,000	E. BAL 1ST OF YEAR	0	0	80,000	77,535	74,996	72,381	69,687	66,912	64,055	61,111
AMORTIZATION PERIOD	23	F. PLUS: INTEREST	0	0	2,400	2,326	2,250	2,171	2,091	2,007	1,922	1,833
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	4,865	4,865	4,865	4,865	4,865	4,865	4,865	4,865
TYPE:		H. BAL END OF YEAR	0	80,000	77,535	74,996	72,381	69,687	66,912	64,055	61,111	58,079
4. A. DATE OF LOAN	2007	ADVANCE	0	0	64,707	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	64,707	E. BAL 1ST OF YEAR	0	0	0	64,707	62,932	61,104	59,221	57,282	55,284	53,227
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	1,941	1,888	1,833	1,777	1,718	1,659	1,597
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	3,716	3,716	3,716	3,716	3,716	3,716	3,716
TYPE:		H. BAL END OF YEAR	0	0	64,707	62,932	61,104	59,221	57,282	55,284	53,227	51,108
5. A. DATE OF LOAN	2008	ADVANCE	0	0	0	148	0	0	0	0	0	0
B. AMOUNT OF LOAN	148	E. BAL 1ST OF YEAR	0	0	0	0	148	143	139	134	129	124
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	4	4	4	4	4	4
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	9	9	9	9	9	9
TYPE:		H. BAL END OF YEAR	0	0	0	148	143	139	134	129	124	118
6. A. DATE OF LOAN	2009	ADVANCE	0	0	0	0	8,543	0	0	0	0	0
B. AMOUNT OF LOAN	8,543	E. BAL 1ST OF YEAR	0	0	0	0	0	8,543	8,308	8,067	7,818	7,562
C AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	256	249	242	235	227
NTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	491	491	491	491	491
E:		H. BAL END OF YEAR	0	0	0	0	8,543	8,308	8,067	7,818	7,562	7,299
7. A. DATE OF LOAN	2010	ADVANCE	0	0	0	0	0	19,146	0	0	0	0
B. AMOUNT OF LOAN	19,146	E. BAL 1ST OF YEAR	0	0	0	0	0	0	19,146	18,621	18,080	17,523
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	0	574	559	542	526
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	1,100	1,100	1,100	1,100
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	19,146	18,621	18,080	17,523	16,949
8. A. DATE OF LOAN	2011	ADVANCE	0	0	0	0	0	0	31,112	0	0	0
B. AMOUNT OF LOAN	31,112	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	31,112	30,259	29,380
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	0	0	933	908	881
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	1,787	1,787	1,787
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	31,112	30,259	29,380	28,474

FINANCIAL FORECAST FORM 325I - SUPPLEMENTAL DEBT SERVICE

	2002	2003 / 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
9. A. DATE OF LOAN	2012	ADVANCE	0	0	0	0	0	0	0	45,367	0	0
B. AMOUNT OF LOAN	45,367	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	45,367	44,123
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	1,361	1,324
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	2,605	2,605
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	45,367	44,123	42,841
10.A. DATE OF LOAN	2013	ADVANCE	0	0	0	0	0	0	0	0	26,331	0
B. AMOUNT OF LOAN	26,331	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	26,331
C. AMORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	790
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	1,512
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	26,331	25,609
11.A. DATE OF LOAN	2014	ADVANCE	0	0	0	0	0	0	0	0	0	25,685
MOUNT OF LOAN	25,685	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	0
MORTIZATION PERIOD	25	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	0
INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	0
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	0	25,685
12.A. DATE OF LOAN		ADVANCE	0	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	0	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	0
C. AMORTIZATION PERIOD	35	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	0
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	0
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	0	0
13.A. DATE OF LOAN		ADVANCE	0	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	0	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	0
C. AMORTIZATION PERIOD	35	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	0
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	0
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	0	0
14.A. DATE OF LOAN		ADVANCE	0	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	0	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	0
C. AMORTIZATION PERIOD	35	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	0
INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	0
E:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	0	0
DATE OF LOAN		ADVANCE	0	0	0	0	0	0	0	0	0	0
B. AMOUNT OF LOAN	0	E. BAL 1ST OF YEAR	0	0	0	0	0	0	0	0	0	0
C. AMORTIZATION PERIOD	35	F. PLUS: INTEREST	0	0	0	0	0	0	0	0	0	0
D. INTEREST RATE	3.00%	G. LESS: PAYMENTS	0	0	0	0	0	0	0	0	0	0
TYPE:		H. BAL END OF YEAR	0	0	0	0	0	0	0	0	0	0

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
99. TOTAL DEBT & DEBT SERVICE OTHER													
A. DEBT FIRST OF YEAR	XXX	XXX	XXX	516,958	576,253	632,604	670,486	641,230	619,482	607,195	605,405	616,030	605,333
B. FUNDS ADVANCED	XXX	XXX	XXX	80,000	80,000	64,707	148	8,543	19,146	31,112	45,367	26,331	25,685
C. INTEREST	XXX	XXX	XXX	15,509	17,288	18,978	20,115	19,237	18,584	18,216	18,162	18,481	18,160
D. DEBT PAYMENTS	XXX	XXX	XXX	36,213	40,937	45,802	49,518	49,527	50,018	51,117	52,904	55,510	57,022
E. DEBT END OF YEAR	XXX	XXX	XXX	576,253	632,604	670,486	641,230	619,482	607,195	605,405	616,030	605,333	592,157

FINANCIAL FORECAST FORM 325K - DETERMINATION OF OPERATING EXPENS

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1. A. TOTAL THERMS REQUIREMENTS	566	592	551	574	574	574	574	574	574	574	574	574	574
B. COST PER THERM PURCHASED ($)	0.3595071	0.5129122	0.59030853	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
B1.FLOW[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0

C. COST OF GAS ($)	203,481	303,644	325,260	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388	344,388
2. A. TOTAL OPER & MAIN EXP ($)	150,310	180,119	200,490	190,464	196,903	202,861	208,340	215,059	221,458	227,537	235,256	242,816	248,095
B. RATIO TO TOTAL UTILITY PLANT	12.64%	14.25%	15.18%	13.60%	13.30%	13.00%	12.70%	12.50%	12.30%	12.10%	12.00%	11.90%	11.70%
FIXED COST INCLUDED	0	0	0										
3. A. TOTAL ADMIN, GEN, & OTH EXP ($)	38,557	45,546	54,952	54,618	56,258	57,737	60,697	61,937	63,016	65,816	68,616	69,376	72,096
B. RATIO TO TOTAL UTILITY PLANT	3.24%	3.60%	4.16%	3.90%	3.80%	3.70%	3.70%	3.60%	3.50%	3.50%	3.50%	3.40%	3.40%
FIXED COST INCLUDED	0	0	0										
4. A. TOTAL DEPR & AMORT EXP ($)	29,340	46,807	49,645	49,016	51,816	54,616	57,416	60,216	63,016	65,816	68,616	71,416	74,216
B. RATIO TO TOTAL UTILITY PLANT	2.47%	3.70%	3.76%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
FIXED COST INCLUDED	0	0	0										
5. A. TOTAL TAXES EXPENSE ($)	12,048	17,642	19,481	19,607	20,727	21,847	22,967	24,087	25,207	26,327	27,447	28,567	29,687
B. RATIO TO TOTAL UTILITY PLANT	1.01%	1.40%	1.48%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%
FIXED COST INCLUDED	0	0	0										
TAL UTILITY PLANT (END OF YEAR) ($)	1,188,833	1,263,675	1,320,470	1,400,470	1,480,470	1,560,470	1,640,470	1,720,470	1,800,470	1,880,470	1,960,470	2,040,470	2,120,470
7. A. CONSUMER ACCT & SALES EXP ($)	47,702	45,826	58,103	53,270	54,031	54,792	55,553	56,314	57,075	57,836	58,597	59,358	60,119
B. COST PER CONSUMER SERVED ($)	60.23	59.59	76.45	70.00	71.00	72.00	73.00	74.00	75.00	76.00	77.00	78.00	79.00
C. AVERAGE NUMBER OF CONSUMERS	792	769	760	761	761	761	761	761	761	761	761	761	761

EXHIBIT
A-7
12-15-05

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	DOCKET NO. G-02528A-03-0205

REBUTTAL

TESTIMONY

OF

JACK SHILLING

CHIEF EXECUTIVE OFFICER
DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.

November 21, 2005

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, address and occupation.

A. My name is Jack Shilling. My business address is 222 Highway 75, P.O. Box 440, Duncan, Arizona. I am Chief Executive Officer of Duncan Valley Electric Cooperative, Inc. ("DVEC"). Through an Operations and Management Agreement, Duncan Valley manages the day-to-day operations of Duncan Rural Services Corporation ("DRSC").

Q. Are you the same Jack Shilling who filed direct testimony in this matter?

A. Yes.

Q. What issues will your rebuttal testimony address?

A. My rebuttal testimony will address Long Term Debt ("LTD"), capital structure and the purchased gas adjustor.

Q. Please summarize your rebuttal recommendations.

A. Given the Staff recommendations for a 30 percent equity percentage goal for DRSC and a recommendation for DRSC to discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative ("DVEC") will require that a higher amount of revenues and LTD be approved, DRSC recommends that an additional LTD of $600,000 be approved to allow DRSC to be brought into compliance with ARS 40-302.D through 2006.

On the basis of the Commission approving $600,000 of additional LTD for DRSC and Staff's recommendation to increase its equity ratio by 5.00% per year, DRSC would further recommend that two additional rate increases be phased-in; one rate increase effective January 1, 2006 for up to 5 percent across the board for all its customers and second rate increase effective January 1, 2007 for up to 5 percent across the board for all its customers.

Finally, DRSC recommends that it be allowed to manage its bank balance as close to $0.0 as possible. DRSC recommends it be allowed to do this by using a 12 month rolling average cost of gas and increase or decrease the average cost of gas by up to $0.10 per month to move the bank balance closer to zero.

II. Long Term Debt and Capital Structure

Q. Does DRSC agree with Staff's recommendation to authorize $330,484 of additional Long Term Debt (LTD)?

A. No, it does not. The Staff recommendations for a 30 percent equity percentage goal for DRSC and a recommendation for DRSC to discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative ("DVEC") will require that a higher amount of revenues and LTD be approved. By making these recommendations together, DRSC will not be able to operate without filing for rate cases every year.

Q. Please explain why the cash advances from DVEC are so important to DRSC and should be allowed to continue.

A. Given the fact that DRSC has a lower number of customers now approximately 760 versus 820 customers in the last rate case, DRSC's capital requirements of approximately $55,000 to $108,000 per year and the increases in purchased gas and other expenses, DRSC's revenues have not kept pace with its costs. According to DRSC's financial forecast, capital additions will continue to average approximately $80,000 for the next five years.

The Company's poor financial condition does not enable it to incur additional debt on its own credit, so CFC or any other lender will require all lending to DRSC to be guaranteed by DVEC since DRSC is not a full member of CFC. The increase in revenues recommended by Staff in this case will be an important step towards restoring the credit worthiness of the utility but is not enough to fund capital improvements or meet the 30 percent equity goal. Consequently, DRSC will be applying for rate increases every year if it is not able to rely on advances from DVEC. Each rate case costs DRSC's members approximately $33,000.

Q. Is it possible for DRSC to operate and remain solvent even if it could file for and receive a rate increase every year?

A. Probably not because DRSC's cash flow would continue to lag given the nature of ratemaking (funds must be invested before rate recovery is allowed) and the amount of time it takes the ACC to process a rate filing.

Q. What is the current amount of Advances from DVEC that DRSC owes?

A. As of September 30, 2005, DRSC owes DVEC approximately $502,000 for cash advances.

Q. Has Staff recommended that all of DRSC's cash advances be converted to LTD?

A. No Staff has not recommended that all of DRSC's cash advances be converted to LTD but has only recommended that $330,484 be converted and the remaining amount of advances of $171,516 be repaid when there are funds available.

Q. Will these unconverted advances ever be repaid?

A. It is unlikely these advances will be repaid for many years given DRSC's financial condition and its capital requirements.

Q. Do Staff's recommendations on DRSC's cash advances bring DRSC into compliance with Arizona Revised Statute ("ARS") 40-302.D?

A. No, Staff's recommendations do not. In fact, Staff's recommendation that DRSC discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative will make DRSC insolvent.

Q. Staff has recommended that DRSC improve its equity ratio by 5 percent each year until it reaches a 30 percent equity ratio. Is it realistic for DRSC to meet a 30 percent equity requirement within a 10 year period as recommended by Staff?

A. No it is not realistic given the revenue requirement recommended by Staff and the future capital requirements of DRSC. DRSC will be applying for rate increases every year if it is not able to rely on advances from DVEC and must meet a 5 percent increase in its equity ratio. This 30 percent equity goal may be more realistic over a 20 year period.

Q. What is the current revenue and rate impact associated with DRSC improving its equity position by 5 percent per year?

A. As of October 2005, DRSC had negative equity of approximately $222,245 and LTD of approximately $1,019,000 including the requested LTD of $502,000. To improve its current equity position, DRSC would need to have positive margins of $32,400 on December 31, 2006. As DRSC's audited financial statements indicate, DRSC's total margins have declined from a negative $18,859 on December 31, 2003 to a negative $49,639 on December 31, 2004 to a negative $69,171 on September 30, 2005. DRSC has not experienced positive margins since its inception. Assuming DRSC can maintain a customer count of 725, improving DRSC's equity position by 5 percent ($32,400) will cost customers $3.72 per month or $44.64 per year.

Q. Given the Staff recommendations that DRSC discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative and meet a 30 percent equity ratio, what does DRSC recommend be done in this case?

A. DRSC recommends that an additional LTD of $600,000 be approved to allow DRSC to be brought into compliance with ARS 40-302.D through 2006. This $600,000 would cover the $502,000 of current advances from DVEC as well as allow DRSC an additional $98,000 for future advances from DVEC.

Q. Staff has expressed a concern that any cash advances used for operating expenses should not be allowed to be converted to LTD because of a cost shift to customers in a later period. Does this apply to DRSC?

A. No it does not. DRSC has experienced a decline in its customer base. DRSC's customer base has been the same customers who have taken service from DRSC for years. Consequently, its existing customers were present when these advances were incurred and are still present today.

Q. Does DRSC have further recommendations on improving its equity ratio and repaying advances from DVEC?

A. Yes, it does. On the basis of the Commission approving $600,000 of additional LTD for DRSC and Staff's recommendation to increase its equity ratio by 5.00% per year, DRSC would further recommend that two additional rate increases be phased-in; one rate increase effective January 1, 2006 for up to 5 percent across the board for all its customers and second rate increase effective January 1, 2007 for up to 5 percent across the board for all its customers. Future rate increases for DRSC are inevitable under the Staff recommendations. This will allow DRSC to repay the $600,000 of additional debt as well as its other debts and operating expenses and will enable DRSC to meet the Staff equity ratio requirements without incurring significant rate increases.

Q. Have DVEC and DRSC considered other measures to address these financial concerns?

A. Yes. As stated in my direct testimony, the DVEC and DRSC Board of Directors have considered reorganizing DRSC such that DRSC would become a department/division of

DVEC as well as other alternatives to address DRSC's financial situation. If DRSC would become a department/division of DVEC, this would allow DRSC access to CFC's low cost financing and restore DRSC's non-taxable status. However, there are many other factors (i.e. income tax issues, debt issues, regulatory approvals, etc.) that must be considered and resolved before any reorganization is approved and can occur.

Q. Does such reorganization completely address the financial concerns of DRSC?

A. No. DRSC will still need to be financially responsible for all expenses, debt service and construction expenditures that it incurs. Consequently, the first step is to improve DRSC's financial condition by increasing rates to a level that interest and debt coverage ratios will be acceptable to outside lenders and where enough cash-flow is being provided through rates to fund expenses, debt payments and construction without the continued need for advances from outside sources.

<u>III. Purchased Gas Adjustor</u>

Q. Are Staff's recommendations for DRSC's Purchased Gas Adjustor (PGA) adequate?

A. No. Staff's recommendations are not adequate given the nationwide increase and fluctuations in natural gas prices. Staff's recommendation that DRSC discontinue the use of unauthorized cash advances from Duncan Valley Electric Cooperative and Staff's recommended revenue requirement. As mentioned in Staff's direct testimony, DRSC has applied for and received a surcharge. Decision No. 68297 approved a $0.45 per therm surcharge for DRSC's customers for all usage on and after December 1, 2005.

Q. What is DRSC's current PGA bank balance?

A. DRSC currently has an under-collected PGA bank balance of approximately $35,000.

Q. Where did the funds come from to pay for the higher cost of gas (under-collected bank balance)?

A. Shortfalls in cash flow due to higher operating expenses are funded from internal funds if available but are most likely funded by advances from DVEC. The current PGA mechanism approved by the Commission is not adequate to address the nation wide increases and fluctuations in the costs of gas. The current mechanism only allows $0.10 increase or decrease over a 12 month period. This $0.10 increase or decrease has not been adequate as demonstrated by the $0.4165 PGA Surcharge approved for DRSC in Decision No. 63369 (February 16, 2001) and the $0.45 per therm surcharge approved Decision No. 68297 (November 8, 2005). The surcharge applications approved are costly and time consuming to prepare and have caused rate shock to DRSC's customers and will not reflect the proper price signals of the market place as these increases are delayed by application approvals and continue past the winter heating season.

Q. Under the Staff recommendations, DRSC will no longer be able to obtain cash advances from DVEC. What are DRSC's recommendations regarding the PGA in the future?

A. DRSC recommends that it be allowed to manage its bank balance as close to $0.0 as possible. DRSC recommends it be allowed to do this by using a 12 month rolling average cost of gas and increase or decrease the average cost of gas by up to $0.10 per month to move the bank balance closer to zero. This will allow DRSC to phase in gas cost increases or decreases to its customers and should mitigate the need for surcharge applications and cash advances from DVEC for gas cost increases.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT A-8 Admitted 12-15-05

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	)	DOCKET NO. G-02528A-05-0314
IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR APPROVAL OF A LOAN IN THE AMOUNT OF $400,000	)	DOCKET NO. G-02528A-03-0205

REJOINDER

TESTIMONY

OF

JACK SHILLING

CHIEF EXECUTIVE OFFICER
DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.

December 12, 2005

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I. INTRODUCTION

Q. Please state your name, address and occupation.

A. My name is Jack Shilling. My business address is 222 Highway 75, P.O. Box 440, Duncan, Arizona. I am Chief Executive Officer of Duncan Valley Electric Cooperative, Inc. ("DVEC"). Through an Operations and Management Agreement, Duncan Valley manages the day-to-day operations of Duncan Rural Services Corporation ("DRSC").

Q. Did you file direct and rebuttal testimony in this matter?

A. Yes.

Q. Was this testimony prepared by you or under your direction?

A. Yes, it was.

Q. What issues will your rebuttal testimony address?

A. My rebuttal testimony will address Long Term Debt ("LTD"), capital structure and the purchased gas adjustor.

Q. Please summarize your rebuttal recommendations.

A. The Staff recommendation for a 30 percent equity percentage goal for DRSC and a recommendation for DRSC to discontinue the use of cash advances from Duncan Valley Electric Cooperative ("DVEC") will require that a higher amount of revenues and LTD be approved. DRSC recommends that additional LTD of $600,000 be approved to allow DRSC to meet its borrowing needs through 2006.

On the basis of the Commission approving $600,000 of additional LTD for DRSC and Staff's recommendation to increase its equity ratio by 5.00% per year, DRSC would further recommend that two additional rate increases be phased-in; one rate increase effective January 1, 2007 for 5 percent across the board for all its customers and a second rate increase effective January 1, 2008 for 5 percent across the board for all its customers.

Finally, DRSC recommends that it be allowed to manage its bank balance as close to $0.0 as possible. DRSC recommends it be allowed to do this by using a 12 month rolling average cost of gas and increase or decrease the average cost of gas by up to $0.10 per month to move the bank balance closer to zero.

II. Long Term Debt and Capital Structure

Q. Does DRSC agree with Staff's recommendation to authorize $330,484 of additional Long Term Debt (LTD) and classify the remaining advances of $171,616 as an equity infusion from DVEC?

A. No, it does not. The $171,616 of remaining advances represent funds that DVEC advanced to DRSC to meet it's operating and capital expenditures. DVEC's intent with providing the advances is that they would be repaid at some point in the future. If the $171,616 of advances is classified as an equity infusion, this amount will likely become a permanent contribution from DVEC.

Q. Does classifying the remaining advances of $171,616 as an equity infusion result in cost shifting to DVEC's members?

A. Yes, it would. DVEC currently has approximately 1,500 customers who are not customers of DRSC. Classifying the remaining advances of $171,616 as an equity infusion will result in cost shifting to these 1,500 members of DVEC because they will probably not be repaid. If these funds are treated as advances or LTD, they will eventually be repaid and no cost shifting will occur.

Q. Please comment on Staff's concerns about cost shifting from DRSC's past to its current members if the advances that paid for DRSC's past operating expenses are converted to LTD?

A. DRSC and DVEC would by far prefer to have a small portion of the past operating expenses of DRSC shifted from a few customers who have left DRSC's system to DRSC's remaining customers than to the approximately 1,500 customers of DVEC who are not customers of DRSC. Classifying the remaining advances of $171,616 as an equity infusion will result in cost shifting to these 1,500 members of DVEC. If these funds are treated as advances or LTD, they will eventually be repaid and no cost shifting will occur.

Q. Staff has described the historical cash advance relationship that has developed between DVEC and DRSC as being inappropriate. Please comment.

A. The fact remains that without these cash advances from DVEC, DRSC would be insolvent, DRSC would have not been able to make the necessary capital improvements to its systems and DRSC's rates would have needed to be significantly higher. DRSC's board and management have attempted to balance the need for significantly higher rates and capital improvements through the use of advances from DVEC.

Q. Has Staff addressed how the $80,000 of projected capital improvements for 2005 and 2006 will be funded by DRSC?

A. No, it has not. Staff has recognized the potential for a cash short-fall with respect to purchased gas costs by recommending approval of a LOC but it has not recognized the cash flow needs associated with additional capital expenditures. DRSC continues to recommend that additional LTD of $600,000 be approved. This $600,000 would cover the $502,000 of current advances from DVEC as well as allow DRSC an additional $98,000 for future advances from DVEC.

Q. Do Staff's surrebuttal recommendations on DRSC's cash advances bring DRSC into compliance with Arizona Revised Statute ("ARS") 40-302.D?

A. No, Staff's surrebuttal recommendations do not. In fact, Staff's recommendation that DRSC discontinue the use of unauthorized cash advances from DVEC will make DRSC insolvent and unable to pay bills when they come due. If the Staff recommended LTD amount of $330,484 is adopted, approval for an additional LTD (or LOC) with DVEC should be approved to address DRSC's capital and operating expenditures in 2005 and 2006.

Q. Staff has stated that its recommendation that DRSC improve its equity ratio by 5 percent will only require a positive margin of $18,194 or the total amount of capital of $363,884 multiplied by 5 percent. Does DRSC agree?

A. No. DRSC does not agree with Staff's calculation. Staff has used a total capital amount that does not include its recommended additional LTD of $330,484. When this amount is included, the Staff calculation of the amount of positive margin required increases to approximately $35,000 (363,884 + 330,484 = $694,368 * 5.00%). Consequently, Staff's calculation of the excess margin that DRSC has to pay for interest, depreciation and the 5 percent equity requirement decreases from the $24,488 to $7,963. The $7,963 amount of excess margins is not enough to meet the $9,280 of expenses associated with the $80,000 of additional capital requirements of DRSC in year one as listed in the table in Dan Zivan's surrebuttal testimony on page 9, lines 13-14. This table also does not take into account that DRSC's salaries and benefits expenses have been increasing by approximately $11,000 per year or any other expenses that may increase in the future.

Q. Given Staff's recommendations in its surrebuttal testimony, will DRSC be able to continue to limit its rate increase requests to once every three years?

A. No, it will not. DRSC will need to apply annually for rate increases to fund its $80,000 annual capital expenditure budget and to increase its equity ratio by 5 percent per year.

Increases in variable interest expense and PGA under-collection could also necessitate annual rate increase filings.

Q. Given Staff's recommendations in its surrebuttal testimony, has DRSC eliminated its recommendation for two additional rate increases of 5 percent in 2007 and 2008?

A. No, it has not. However, DRSC is correcting and modifying proposal that appeared in my rebuttal testimony. On the basis of Staff's surrebuttal testimony recommendations, DRSC would further recommend that two additional rate increases be phased-in; one rate increase effective January 1, 2007 for 5 percent across the board for all its customers and a second rate increase effective January 1, 2008 for 5 percent across the board for all its customers. I had mistakenly stated 2006 and 2007 in my rebuttal testimony. Also, DRSC believes that it will be simpler for the Commission to authorize in this order a precise amount of 5 percent rather than my original "up to" proposal.

III. Purchased Gas Adjustor

Q. Does Staff's recommendation to allow a DRSC to borrow funds from DVEC under a Line of Credit ("LOC") agreement address DRSC's concerns regarding gas price fluctuations and DRSC's Purchased Gas Adjustor (PGA) being able to recover gas costs in a timely fashion?

A. No, it does not completely address these concerns. DRSC appreciates Staff's attempt to address the cash flow issues associated with the PGA due to higher gas costs. However, Staff's recommendation is contrary to its other recommendations for DRSC to seek rate relief in a more timely fashion, to avoid the use of advances from DVEC and to avoid financing operating expenses. As stated previously in my testimony in this case, DRSC will continue to experience price fluctuations in its cost of gas that can not be adequately addressed by its current PGA. If DRSC's PGA rate can not be adequately increased or decreased to recover higher or lower gas costs, then DRSC will need an advance or LOC from DVEC to finance an operating expense, DRSC's customers will have to pay interest on the amount of the advance or LOC and the higher cost of winter gas is shifted to summer irrigation users who only use a small amount of gas in the winter.

Q. Is DRSC's existing PGA mechanism adequate to recover or refund significant gas price increases or decreases?

A. No, it is not. DRSC's current PGA mechanism is inadequate to address significant price fluctuations as demonstrated by the need for DRSC to file two surcharge applications in the last four years. Decision No. 63369 (February 15, 2001) approved a surcharge for DRSC of $0.4165 per therm. Decision No. 68297 (November 14, 2005) approved a surcharge for DRSC of $0.45 per therm. The current PGA mechanism has caused the DRSC to request a higher and longer surcharge increase than what would have been necessary had DRSC been allowed to manage its bank balance as close to $0.00 as possible. Under DRSC's PGA proposal, DRSC would be able to gradually increase or decrease the PGA rate when price fluctuations start to occur which will result in lower price fluctuations and better price signals for its customers.

Q. Have DRSC's recommendations regarding the PGA changed from what you stated in your rebuttal testimony?

A. No, for the reasons stated above. DRSC recommends that it be allowed to manage its bank balance as close to $0.00 as possible. DRSC recommends it be allowed to do this by using a 12 month rolling average cost of gas and increase or decrease the average cost of gas by up to $0.10 per month to move the bank balance closer to zero. This will allow DRSC to phase in gas cost increases or decreases to its customers, should mitigate rate shock, should avoid cost shifting among customer classes and should mitigate the need for surcharge applications and cash advances or LOC from DVEC for gas cost increases.

Q. Does that conclude your rejoinder testimony?

A. Yes, it does.

EXHIBIT
S-1
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF DUNCAN RURAL SERVICES CORPORATION DEVOTED ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-02528A-05-0314

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER, 8 2005

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EXECUTIVE SUMMARY
DUNCAN RURAL SERVICES CORPORATION
DOCKET NO. G-02528A-05-0314

Staff's testimony discusses Utilities Division Staff's ("Staff") review of Duncan Rural Services Corporation ("Duncan" or "Company") Cost of Service Study ("COSS") for the rate case filed with the Arizona Corporation Commission ("Commission"), and presents the results of its analysis.

Based on its review of Duncan's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Duncan performed the COSS consistent with the methodology generally accepted in the industry, and utilized the COSS model in developing the allocation factors appropriately.

2. Staff further concludes that, based on the evaluation of Duncan's COSS model and some minor changes Staff made in Schedules G-5 through G-7, the results of COSS are satisfactory. These changes are described in detail in the main body of the testimony under Conclusions and Recommendations.

3. Staff eliminated a duplicate G Schedule and renamed several Schedules contained in the Company's filing. Staff recommends that Duncan continue to utilize the current COSS model including the modifications Staff made in the G Schedules in any future rate proceeding. These modifications include the appropriate titles according to the A.A.C. Rule R14-2-103.

4. Staff further recommends that Duncan's COSS cost allocations and factors be accepted with Staff's aforementioned modifications, which are reflected in the attached COSS G-Schedules under Exhibit 2:

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Prem K. Bahl. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I graduated from South Dakota State University with a Masters degree in Electrical Engineering in May 1972. I received my Professional Engineering ("P.E.") License in the state of Arizona in 1978. My Bachelor of Science degree in Electrical Engineering is from the Agra University, India in 1957.

Q. Please describe your pertinent work experience.

A. Please see my bio, which is attached as Exhibit 1.

Q. As part of your assigned duties at the Commission, did you perform an analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's review of Duncan Rural Services Corporation ("Duncan" or "Company") Cost of Service Study ("COSS") for the rate case, and present the results of this review.

II. COST OF SERVICE STUDY – REVIEW PROCESS

Q. What is the purpose of a COSS?

A. There are three steps to take in performing a COSS. They are: 1) functionalization; 2) classification; and 3) allocation. First, the COSS enables us to determine the system's cost of service by classifying the utility's costs (investments and expenses) by function, such as demand-related, commodity-related, and customer-related functions. Second, the study breaks down these costs by customer classes to reflect as closely as possible the cost causation by respective customer classes. Third, the results of the COSS provide a benchmark for the revenues needed from each customer category by appropriately allocating the revenue requirement for each customer class.

Q. Is there a standard COSS model?

A. There is no standard methodology for designing a COSS, but it is generally advisable to follow a range of alternatives to identify which allocations are more reasonable than others. For that reason, the COSS should be used as a general guide only and as one of many considerations in designing rates.

Q. What was the process Staff used in reviewing Duncan's COSS?

A. First, I reviewed the model used by Duncan in developing various allocation factors in the COSS. Second, I reviewed the Test Year ("TY 2004") rate base, revenues and expenses in the filed rate case, adjusted by Duncan's Pro Forma adjustments, and matched them with the appropriate schedules contained in the application. Third, I incorporated the revenue allocations and operating expense adjustments of Staff witnesses, Steve Irvine and Dan Zivan, in the COSS.

Q. Did Staff conduct a separate independent COSS?

A. After studying Duncan's model, Staff decided that the best method for review would be to replicate Duncan's COSS and make the appropriate Staff revisions and adjustments. The accuracy of the COSS model was established by the fact that all the revisions and adjustments flowed through the relevant G-Schedules. Furthermore, Duncan used the same COSS model that was used and approved by the Commission in the last rate case (Docket No. G-02527A-00-0392).

Q. Did Staff make any changes in Duncan's COSS Schedules?

A. Yes. Staff made the following changes in the G Schedules.

1. Incorporated Staff's revenue and operating expense adjustments.
2. Corrected some typographical errors in the designation of allocation factors in Schedules G-5 through G-7.
3. Eliminated the duplicate Schedule G-4 ("Allocation of Rate Base") and replaced it with the "Expense Allocation to Classes" Schedule G-4, and renumbered the remaining Schedules as G-5 through G-7.
4. Relabeled the titles of Schedules G-5 through G-7 in accordance with the A.A.C. Rule R14-2-103.
5. Introduced a new allocation factor, F10, in Schedules G-6 and G-7 that was erroneously labeled as F-3.
6. Included in Schedule G-7 the missing Allocation Factor F-4 for the Weighted Customer Accounts.

Q. What was the effect of the above-noted changes in the Allocation Factors?

A. The above-noted changes in the Allocation Factors did not affect the COSS results.

III. ALLOCATION OF DISTRIBUTION MAINS

Q. What comments does Staff have regarding Duncan's allocation of Distribution Mains?

A. This account is the largest single plant account. It constitutes approximately 67 percent of Gross Distribution Plant in Service, according to Duncan's figures used in its COSS. Duncan rightly allocated one hundred percent (100%) of the cost of Distribution Mains to peak demand, as was done in the last rate case.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the COSS?

A. Based on its review of Duncan's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Duncan performed the COSS consistent with the methodology generally accepted in the industry, and developed the allocation factors appropriately, except for the modifications made by Staff in terms of correcting some typographical errors in the allocation factors in schedules G-5 through G-7, and relabeling another factor in Schedules G-6 and G-7, which was erroneously designated by the Company.

2. Staff further concludes that, based on the evaluation of the COSS model utilized by Duncan, and the changes Staff made in the allocation factors mentioned under Item 4 below, the results of Duncan's COSS are reasonable.

3. Staff recommends that in any future rate proceeding, Duncan continue to utilize the current COSS model, including any appropriate revisions to the allocation factors for allocating expenditures.

4. Staff further recommends that the Commission accept Duncan's COSS cost allocations and factors with the following adjustments and modifications, which are reflected in the attached COSS G-Schedules under Exhibit 2.
   a. Include Staff's revenue allocation adjustment by class.
   b. Include Staff's operating expense adjustments to Duncan's filing.
   c. Replace Schedule G-4, which is duplicate of the "Allocation of Rate Base" Schedule G-3, with the "Expense Allocation to Classes" Schedule G-4, and renumber the remaining Schedules as G-5 through G-7.
   d. Schedules G-5 and G-6: change the Allocation Factor for Meters and House Regulators from F-5 to F-4.
   e. Schedules G-6 and G-7: relabel the Allocation Factor for Operating Expenses, under Function of Salaries and Wages, F-3, as F-10.
   f. Schedule G-7: include the missing Allocation Factor F-4 for the Weighted Customer Accounts.

Q. Does this conclude your pre-filed testimony?

A. Yes it does.

EXHIBIT 1

Duncan Rural Services Corporation
(Docket No. G-02528A-05-0314)

ACC Staff Prem Bahl's Bio

Prem Bahl's Bio

Mr. Bahl worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and has been re-employed at the Commission as an Electric Utilities Engineer since June 2002. During this period of over thirteen years, he has conducted engineering evaluations of utility rate cases and financing cases, including analyses of cost of service studies performed by Southwest Gas and rural electric cooperatives. His responsibilities have included review of electric utilities' generation and transmission plans, inspection of power stations, and transmission and distribution facilities. Mr. Bahl was involved with the development of retail competition in Arizona and of DesertStar, an Independent System Operator ("ISO"), later renamed as WestConnect, a Regional Transmission Operator ("RTO"). He was Chairman of the System Reliability Working Group, which evaluated the impact of competition on system reliability and recommended the establishment of the Arizona Independent System Administrator ("AZISA") as an interim organization until commercial operation of DesertStar was implemented. Since rejoining the Commission, Mr. Bahl has reviewed utilities' load curtailment plans, and coordinated with the Commission consultants to hold two workshops to report on the second Biennial Transmission Assessment ("BTA") 2002-2011, and the third BTA 2004-2013, in the state of Arizona. He is responsible for the compliance of power plant and line siting cases.

From July 1998 to August 2000, Mr. Bahl was Chief Engineer at the Residential Utility Consumer Office. During this time period, he performed many of the duties he performed at the Commission. He was involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability, and modifications of interconnection standards currently specified by the jurisdictional utilities. Mr. Bahl was a member of the AZISA Board of Directors from September 1999 to June 2000. He was involved in the deliberations of the Market Interface Committee of the North American Electric Reliability Council.

From July 2001 to June 2002, Mr. Bahl had his own consulting engineering firm, and was involved with deregulation of electric power industry, and formation of RTO West and the MidWest ISO.

Mr. Bahl has a Masters in Electrical Engineering from the South Dakota State University, and is a registered Professional Engineer in the state of Arizona. He has published and presented a number of technical papers at the national and international conferences regarding formation of ISOs and RTOs; transmission issues and distributed generation. In April 2005, he chaired a national conference on "Western Power Supply" in Los Angeles, California.

Prior to his employment with the Commission, Mr. Bahl was an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately twenty eight years, including ten years with the Punjab State Electricity Board ("PSEB") in India from 1960 to 1970. He was Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the USA in 1970.

EXHIBIT 2

Duncan Rural Services Corporation
(Docket No. G-02527A-04-0301)

Cost of Service Study Schedules G-1 thru G-7

DUNCAN RURAL SERVICES CORPORATION
COST OF SERVICE SUMMARY - PRESENT RATES
TEST YEAR ENDED DECEMBER 31, 2004

DESCRIPTION	TOTAL	250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
Operating Revenues	**325,812**	**300,393**	**17,421**	**7,998**
Operating Expenses:				
Purchased Gas	-	-	-	-
Distribution Expense - Operations	154,097	134,924	12,508	6,665
Distribution Expense - Maintenance	54,824	48,107	4,413	2,304
Customer Account Expense	60,129	58,455	1,509	165
Administrative & General Expense	56,520	50,520	4,490	1,510
Depreciation	49,646	44,090	3,809	1,747
Property Taxes	19,639	17,021	1,656	962
Tax Expense - Other (Income, etc.)	(23,047)	(20,601)	(1,831)	(615)
Interest Expense -Other	367	357	9	1
Total Operation Expenses	**372,175**	**332,873**	**26,563**	**12,739**
Operating Income (Loss)	**(46,363)**	**(32,480)**	**(9,142)**	**(4,741)**
Rate Base	**758,058**	**672,374**	**58,472**	**27,212**
% Return - Present Rates	**-6.12%**	**-4.83%**	**-15.63%**	**-17.42%**
Return Index	**1.00**	**0.79**	**2.56**	**2.85**

DUNCAN RURAL SERVICES CORPORATION
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2004

DESCRIPTION	TOTAL	250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
Operating Revenues (1)	477,825	385,400	78,360	14,065
Operating Expenses:				
Purchased Gas	-	-	-	-
Distribution Expense - Operations	154,097	134,924	12,508	6,665
Distribution Expense - Maintenance	54,824	48,107	4,413	2,304
Customer Account Expense	60,129	58,455	1,509	165
Administrative & General Expense	56,520	50,520	4,490	1,510
Depreciation	49,646	44,090	3,809	1,747
Property Taxes	19,639	17,021	1,656	962
Tax Expense - Other (Income, etc.)	12,305	10,999	978	328
Interest Expense -Other	367	357	9	1
Total Operation Expenses	**407,524**	**364,473**	**29,372**	**13,682**
Operating Income (Loss)	**70,301**	**20,927**	**48,988**	**383**
Rate Base	**758,058**	**672,374**	**58,472**	**27,212**
% Return - Proposed Rates	**9.27%**	**3.11%**	**83.78%**	**1.41%**
Return Index	**1.00**	**0.34**	**9.03**	**0.15**

Note:

(1) Operating Revenues exclude recovery of Purchased Gas cost.

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
ALLOCATION OF RATE BASE

			CONSUMER CLASS		
DESCRIPTION	**FACTOR**	**TOTAL**	**250cfh & Below**	**50 & < 425 cfh**	**425 & < 1k cfh**
GROSS PLANT IN SERVICE:					
Demand	D-1	926,778	803,225	78,147	45,406
Commodity	CM-1	-			
Customer - Weighted	C-1	415,620	388,358	25,072	2,190
Customer - Unweighted	C-2	-			
Total		**1,342,398**	**1,191,583**	**103,219**	**47,596**
ACCUMULATED DEPRECIATION:					
Demand	D-1	395,086	342,415	33,314	19,356
Commodity	CM-1	-			
Customer - Weighted	C-1	177,178	165,557	10,688	933
Customer - Unweighted	C-2	-			
Total		**572,264**	**507,972**	**44,002**	**20,289**
NET PLANT IN SERVICE		**770,134**	**683,611**	**59,217**	**27,307**
Customer Deposits & Def. Tax:					
Demand	D-1	19,554	16,947	1,649	958
Commodity	CM-1	-			
Customer - Weighted	C-1	20,064	18,748	1,210	106
Customer - Unweighted	C-2	-			
Total		**39,618**	**35,695**	**2,859**	**1,064**
WORKING CAPITAL:					
Demand	D-1	18,839	16,327	1,589	923
Commodity	CM-1	-	-	-	-
Customer - Weighted	C-1	8,703	8,132	525	46
Customer - Unweighted	C-2	-	-	-	-
Total		**27,542**	**24,459**	**2,114**	**969**
TOTAL RATE BASE		**758,058**	**672,374**	**58,472**	**27,212**

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
EXPENSE ALLOCATION TO CLASSES OF SERVICE

			CONSUMER CLASS		
DESCRIPTION	**FACTOR**	**TOTAL**	**250cfh & Below**	**>250 & < 425 cfh**	**>425 & < 1k cfh**
REVENUES:					
Gas Sales - Adjusted		320,602	295,328	17,291	7,984
Service Charges & Other Revenues	C-2	5,210	5,065	131	14
Total (1)		**325,812**	**300,393**	**17,421**	**7,998**
OPERATING EXPENSE:					
Purchased Gas	CM-1	-	-	-	-
Distribution Expense - Operations:					
Demand	D-1	133,884	116,036	11,289	6,559
Commodity	CM-1	-			
Customer - Weighted	C-1	20,213	18,888	1,219	106
Customer - Unweighted	C-2	-			
Total		**154,097**	**134,924**	**12,508**	**6,665**
Distribution Expense - Maintenance:					
Demand	D-1	46,098	39,953	3,887	2,258
Commodity	CM-1	-			
Customer - Weighted	C-1	8,726	8,154	526	46
Customer - Unweighted	C-2	-			
Total		**54,824**	**48,107**	**4,413**	**2,304**
Customer Accounts Expense:					
Demand	D-1	-			
Commodity	CM-1	-			
Customer - Weighted	C-1	-			
Customer - Unweighted	C-2	60,129	58,455	1,509	165
Total		**60,129**	**58,455**	**1,509**	**165**
Admin. & General Expense:					
Demand	D-1	26,743	23,178	2,255	1,310
Commodity	CM-1	2,930	1,801	1,040	89
Customer - Weighted	C-1	14,794	13,824	892	78
Customer - Unweighted	C-2	12,053	11,717	303	33
Total		**56,520**	**50,520**	**4,490**	**1,510**

Note: (1) Total Revenues exclude recovery of Purchased Gas cost.

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
EXPENSE ALLOCATION TO CLASSES OF SERVICE

			CONSUMER CLASS		
DESCRIPTION	FACTOR	TOTAL	250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
Depreciation:					
Demand	D-1	33,958	29,431	2,863	1,664
Commodity	CM-1	-			
Customer - Weighted	C-1	15,688	14,659	946	83
Customer - Unweighted	C-2	-			
Total		**49,646**	**44,090**	**3,809**	**1,747**
Property Taxes:					
Demand	D-1	13,433	11,642	1,133	658
Commodity	CM-1	-			
Customer - Weighted	C-1	6,206	5,379	523	304
Customer - Unweighted	C-2	-			
Total		**19,639**	**17,021**	**1,656**	**962**
ADJUSTED TY Tax Expense - Other:					
Demand	D-1	(10,905)	(9,451)	(920)	(534)
Commodity	CM-1	(1,195)	(735)	(424)	(36)
Customer - Weighted	C-1	(6,033)	(5,637)	(364)	(32)
Customer - Unweighted	C-2	(4,914)	(4,778)	(123)	(13)
Total		**(23,047)**	**(20,601)**	**(1,831)**	**(615)**
PROPOSED Tax Expense - Other:					
Demand	D-1	5,822	5,046	491	285
Commodity	CM-1	638	392	227	19
Customer - Weighted	C-1	3,221	3,010	194	17
Customer - Unweighted	C-2	2,624	2,551	66	7
Total		**12,305**	**10,999**	**978**	**328**
Interest Expense - Other:					
Demand	D-1	-			
Commodity	CM-1	-			
Customer - Weighted	C-1	-			
Customer - Unweighted	C-2	367	357	9	1
Total		**367**	**357**	**9**	**1**
TOTAL OPERATING EXPENSES		**372,175**	**332,873**	**26,563**	**12,739**
OPERATING INCOME (LOSS)		**(46,363)**	**(32,480)**	**(9,142)**	**(4,741)**
OPERATING INCOME PERCENT		**-14.23%**	**-10.81%**	**-52.47%**	**-59.28%**

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DISTRIBUTION OF RATE BASE BY FUNCTION

DESCRIPTION	FACTOR	TOTAL	FUNCTION	SPECIFIC	DEMAND	COMMODITY	CUST. - WT	CUST.
GROSS UTILITY PLANT IN SERVICE								
Distribution Plant:								
Distribution Mains	F-3	869,079	869,079	-	869,079			
City Gates	F-3	27,130	27,130	-	27,130			
Services	F-4	191,962	191,962	-			191,962	
Meters & Regulators	F-4	209,535	209,535	-			209,535	
Total Distribution Plant	F-7	**1,297,706**	**1,297,706**	-	**896,209**	-	**401,497**	-
Percent		**100.00%**	**100.00%**	**0.00%**	**69.06%**	**0.00%**	**30.94%**	**0.00%**
General Plant:								
Office Furniture & Improvements		2,000	2,000		1,368		632	
Tools & Shop Equipment		22,553	22,553		15,426		7,127	
Lab Equipment		13,369	13,369		9,144		4,225	
Stores, Power, Communication & Misc. Equip.		6,769	6,769		4,630		2,139	
Total General Plant	F-7	**44,691**	**44,691**	-	**30,569**	-	**14,122**	-
Percent		**100.00%**	**100.00%**	**0.00%**	**68.40%**	**0.00%**	**31.60%**	**0.00%**
GROSS PLANT IN SERVICE		**1,342,397**	**1,342,397**	-	**926,778**	-	**415,619**	-
PERCENT		**100.00%**	**100.00%**	**0.00%**	**69.04%**	**0.00%**	**30.96%**	**0.00%**
ACCUMULATED DEPRECIATION:								
Distribution Plant	F-7	549,867	549,867	-	379,623	-	170,244	-
General Plant	F-7	22,397	22,397	-	15,463	-	6,934	-
Total Accumulated Depreciation		**572,264**	**572,264**	-	**395,086**	-	**177,178**	-
Customer Deposits & Deferred Taxes		**39,618**	**39,618**		**19,554**		**20,064**	
WORKING CAPITAL:								
Materials & Supplies Inventory	F-7	27,542	27,542		18,839	-	8,703	-
Prepaids	F-9	-	-		-	-	-	-
Total Working Capital		**27,542**	**27,542**	-	**18,839**	-	**8,703**	-
TOTAL RATE BASE		**758,057**	**758,057**		**550,531**	-	**267,208**	-

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DISTRIBUTION OF EXPENSE BY FUNCTION

DESCRIPTION	FACTOR	TOTAL	FUNCTION	SPECIFIC	DEMAND	COMMODITY	CUST. - WT	CUST.
Purchased Gas	F-2	-	-			-		
Distribution Operating Expenses:								
Supervision & Engineering	F-3	950	950		950			
Mains & Services	F-3	110,026	110,026		110,026			
Measuring & Reg Stations	F-1	13,753	13,753		13,753			
Meters and House Regulators	F-4	20,214	20,214				20,214	
Other Operating Expenses	F-3	9,155	9,155		9,155			
Total Operating Expenses		154,097	154,097	-	133,884	-	20,214	-
Distribution Maint. Expenses:								
Supervision & Engineering	F-3	-	-		-			
Mains & Services	F-3	46,098	46,098		46,098			
Measuring & Reg Stations	F-1	-	-		-			
Meters and House Regulators	F-4	8,726					8,726	
Other Equipment	F-3	-	-		-			
Total Maint. Expenses		54,824	46,098	-	46,098	-	8,726	-
Meter Reading Expenses	F-6	25,048	25,048					25,048
Consumer Expense	F-6	30,523	30,523					30,523
Info. and Instructional Ads & Uncollectibles	F-6	4,558	4,558					4,558
Total Customer Accounts Expenses:		60,129	60,129	-	-	-	-	60,129
Administrative & General Exp.	F-8	56,520	53,589	2,931	26,742	2,931	14,795	12,052
Depreciation	F-7	49,645	49,645		33,957		15,688	
Property Taxes	F-7	19,639	19,639		13,433		6,206	
Taxes - Other	F-8	(23,048)	(23,048)		(10,905)	(1,195)	(6,033)	(4,915)
Interest Expense - Other	F-6	367	367					367
TOTAL OPERATING EXPENSES		372,174	360,517	2,931	243,209	1,736	59,595	67,634
FUNCT. OF SALARIES & WAGES								
Operating Expenses	F-10	129,955	118,242	11,713	59,121	11,713	59,121	
Maintenance Expenses	F-3	47,741	47,741		47,741			
Meter Reading & Installation	F-6	21,681	21,681					21,681
Customer Accounting	F-6	26,480	26,480					26,480
Total		225,857	214,144	11,713	106,862	11,713	59,121	48,161
Percent	F-8	**100.00%**	**94.81%**	**5.19%**	**47.31%**	**5.19%**	**26.18%**	**21.32%**
FUNCTION OF O&M LESS PG		372,174	360,517	2,931	243,209	1,736	59,595	67,634
Percent	F-9	**100.00%**	**96.87%**	**0.79%**	**65.35%**	**0.47%**	**16.01%**	**18.17%**

DUNCAN RURAL SERVICES CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
ALLOCATION FACTORS

FUNCTION FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMODITY	WEIGHTED CUSTOMER	CUSTOMER
F-1	Demand	100.00%	100.00%			
F-2	Commodity	100.00%		100.00%		
F-3	Distribution Mains	100.00%	100.00%			
F-4	Customer Accts - Weighted	100.00%			100.00%	
F-6	Customer Accounts	100.00%				100.00%

DERIVED FUNCTION FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMODITY	WEIGHTED CUSTOMER	CUSTOMER
F-7	Gross Plant in Service	100.00%	68.40%		31.60%	
F-8	Salaries & Wages	100.00%	47.31%	5.19%	26.18%	21.32%
F-9	O & M Less Purchased gas	100.00%	65.35%	0.47%	16.01%	18.17%
F-10	Salaries & Wages - Oper Exp	100.00%	45.49%	9.01%	45.49%	

CLASS ALLOCATION FACTORS	DESCRIPTION	TOTAL	CUSTOMER CLASS 250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
D-1	Winter Peak Demand	100.000%	86.669%	8.432%	4.899%
CM-1	Commodity	100.000%	61.454%	35.493%	3.053%
C-1	Customer - Weighted	100.000%	93.441%	6.032%	0.527%
C-2	Customer - Unweighted	100.000%	97.216%	2.510%	0.274%

EXHIBIT
S-2
12-15-05 Admitted

Revised Schedule G-2

DUNCAN RURAL SERVICES CORPORATION
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2004

DESCRIPTION	TOTAL	250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
Operating Revenues	**473,397**	**403,965**	**55,297**	**14,135**
Operating Expenses:				
Purchased Gas	-	-	-	-
Distribution Expense - Operations	154,097	134,924	12,508	6,665
Distribution Expense - Maintenance	54,824	48,107	4,413	2,304
Customer Account Expense	60,129	58,455	1,509	165
Administrative & General Expense	56,520	50,520	4,490	1,510
Depreciation	49,646	44,090	3,809	1,747
Property Taxes	19,639	17,021	1,656	962
Tax Expense - Other (Income, etc.)	12,305	10,999	978	328
Interest Expense -Other	367	357	9	1
Total Operation Expenses	**407,524**	**364,473**	**29,372**	**13,682**
Operating Income (Loss)	**65,873**	**39,492**	**25,925**	**453**
Rate Base	**758,058**	**672,374**	**58,472**	**27,212**
% Return - Proposed Rates	**8.69%**	**5.87%**	**44.34%**	**1.66%**
Return Index	**1.00**	**0.68**	**5.10**	**0.19**
Allocated Interest - Long-Term	**23,007**	**20,407**	**1,775**	**826**

EXHIBIT
S-3
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THER APPLICATION OF)
DUNCAN RURAL SERVICES CORPORATION)
FOR A RATE INCREASE)

DOCKET NO. G-02528A-05-0314

DIRECT

TESTIMONY

OF

DANIEL ZIVAN

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 8, 2005

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SCHEDULES

EXECUTIVE SUMMARY
DUNCAN RURAL SERVICES CORPORATION
DOCKET NO. G-02528A-05-0314

Duncan Rural Services Corporation ("Duncan Rural") is a non-profit corporation that supplies gas service to approximately 750 customers in Greenlee County, Arizona. Duncan Rural is operated by Duncan Valley Electric Cooperative ("DVEC") through a management contract. DVEC controls Duncan Rural's board of directors. Duncan Rural's current rates were approved by the Commission in Decision No. 64869 (June 5, 2002).

Rate Application:
Duncan Rural proposed a $147,406, or 22.70 percent, revenue increase from $649,377 to $796,783. The proposed revenue increase, as filed, would produce an operating margin of $61,846 for an 8.01 percent rate of return on an original cost rate base of $772,408. The $147,406 proposed revenue increase includes $33,179[1] of margin revenue and $114,227[2] of base cost of gas revenue. Only the $33,179 margin increase is comparable to Staff's recommended revenue increase. Duncan Rural requests a 2.0 times interest earned ratio ("TIER') and a 1.38 debt service coverage ratio ("DSC").

Staff recommends removing purchased gas cost and its recovery from revenue and expenses to recognize them in a fuel adjustor mechanism. Staff further recommends a revenue requirement of $473,218. Staff's proposed revenue would provide a $147,406, or 45.24 percent, increase over adjusted test year margin revenues of $325,812 and an operating margin of $65,665 for an 8.66 percent rate of return on a Staff adjusted original cost rate base of $758,057. Operating revenue of $473,218 would produce a 3.38 TIER and a 1.64 DSC.

Finance Application:
Duncan Rural proposes to convert $268,988 of its $443,584 unauthorized cash advances from DVEC to a 25-year note at a variable interest rate equal to Arizona Electric Power Cooperative Inc.'s ("AEPCO") variable interest rate earned on funds. Staff determined that Duncan Rural used $330,484 of the advances for capital improvements and recommends authorization to convert that amount to a 25-year note on the terms proposed. Staff further recommends discontinuation of unauthorized cash advances from DVEC to Duncan Rural.

Duncan Rural's capital structure consists of 142.07 percent debt and negative 42.07 percent patronage equity. The negative equity exists due to continued net losses experienced by Duncan Rural. Duncan Rural's highly leveraged capital structure has negative consequences in the future.

Staff recommends that Duncan Rural adhere to an equity plan designed to improve its capital structure. The recommended capital plan requires Duncan Rural to make a filing with the Commission for 2005 and each year thereafter detailing its calendar year end equity position. The recommended equity plan requires Duncan Rural to improve its equity position by 5 percent

[1] $147,046 revenue increase - $114,827 base cost of gas revenue = $33,178 margin revenue
[2] 574,136 Test Year therm sales x [($0.56 proposed base cost of gas) - ($0.36 current base cost of gas)]=$114,827

each year. Staff recommends that in the event Duncan Rural does not improve its cumulative equity position by an average of 5 percent (using its December 31, 2005 position as a base) at the end of any calendar year until patronage equity is a minimum of 30 percent of total capital that the Cooperative be required to file a rate application within 180 days of the end calendar year that the 5 percent cumulative average increase in patronage equity is not achieved. However, Duncan Rural may be granted a waiver from filing a rate application if it provides a written explanation as to why it did not achieve its equity goal and it can demonstrate to Staff's satisfaction that it is likely that it will achieve the cumulative equity goal in Staff's recommendation within a reasonable timeframe without any rate adjustment. Such demonstration should be provided within 90 days of the end of the calendar year. In no instance shall Duncan Rural fail to achieve its cumulative equity improvement goal for three consecutive years without filing a rate application. Staff also recommends that the Commission prohibit distribution of patronage dividends until Duncan Rural has achieved a capital structure composed of at least 20 percent patronage equity.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Daniel Zivan. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, analyze financial information related to financings, sales of assets and other matters. I am also responsible for preparing written reports, testimonies, and schedules that include Staff recommendations to the Commission and testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. In 2001, I graduated from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. My course of studies included classes in corporate and international finance, investments, accounting, and economics. In 2005, after three years of working in financial analysis, financial operations and accounting, I accepted employment with the Commission as a Public Utilities Analyst in the Financial and Regulatory Analysis Section. I have attended seminars on rate design, rate making and financial modeling during my employment with the Commission.

Q. What is the scope of your testimony in this case?

A. I present Staff's analysis and recommendations in the areas of rate base, operating income, revenue requirement and capital structure regarding Duncan Rural Services Corporation's

("Duncan Rural" or "Cooperative") application for a permanent rate increase. I also present Staff's recommendations on the Cooperative's application requesting authorization for debt financing and recommend an equity improvement plan. Staff witness Steve Irvine is presenting Staff's recommendations regarding the base cost of gas, fuel adjustor, and rate design. Staff witness Prem Bahl is presenting Staff's analysis and recommendations with regard to the Cost of Service Study.

Q. What is the basis of Staff's recommendations?

A. Staff performed a regulatory audit of Duncan Rural's application and records to determine the Cooperative's rate base, adjusted test year operating results and revenue requirement. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

Q. Briefly summarize how your testimony is organized.

A. My testimony is organized in five sections. Section I is this introduction. Section II summarizes a brief history of customer complaints. Section III discusses the rate application including Staff's recommendations for rate base, operating income and revenue requirement. Section IV discusses the Cooperative's unauthorized incurrence of debt. Section V discusses the Cooperative's request to convert accounts payable to Duncan Valley Electric Cooperative ("DVEC") to long-term debt. Section VI discusses the Cooperative's capital structure. Section VII presents Staff's recommendation for an equity improvement plan.

Q. Please review the background of the Cooperative's rate application.

A. Duncan Rural initially filed a rate application on April 19, 2005. Staff filed a letter of deficiency pertaining to that application on May 27, 2005. On June 9, 2005, Duncan Rural filed a new application that corrected the deficiencies in its initial application and requested that the initial application be disregarded. Staff filed a letter finding the second application sufficient on June 22, 2005.

Duncan Rural supplies gas service to approximately 750 customers in Greenlee County, Arizona. DVEC has a contract to manage and operate Duncan Rural. DVEC controls Duncan Rural's board of directors[3] and serves approximately 2,500 electric customers. A majority of Duncan Rural's gas customers are also electric customers of DVEC. Duncan Rural's current rates were approved by the Commission in Decision No. 64869 (June 5, 2002).

Q. What primary reasons did Duncan Rural state for requesting a permanent rate increase?

A. Duncan Rural's application discusses two primary reasons: increased purchased gas costs and a decreasing customer base. Additionally, the application states that Duncan Rural incurred a Test Year operating loss of $46,967 and a total margin loss of $77,970.

Q. What Test Year did Duncan Rural use in this filing?

A. Duncan Rural's rate filing is based on the twelve months ended December 31, 2004 ("Test Year").

[3] According to Note 3 of the Cooperative's 2004 audited financial statements, the Cooperative has three membership classes with voting entitlements as follows: 1 Class A member (DVEC) entitled to 1,000 votes; 685 Class B members entitled to one vote each and 19 Class C members entitled to one vote each.

II. CONSUMER SERVICE

Q. Please provide a brief history of customer complaints received by the Commission regarding Duncan Rural.

A. The Commission's Consumer Service Section received one complaint pertaining to Duncan Rural for the period of September 7, 2002 through September 10, 2005. This complaint has been resolved and closed.

III. RATE APPLICATION

Summary of Proposed Revenues

Q. Please summarize the Cooperative's filing.

A. Duncan Rural proposes total annual operating revenue of $796,783. The Cooperative's proposed revenue, as filed, represents an increase of $147,406, or 22.70 percent, over Test Year revenue of $649,377.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends a margin revenue requirement (excludes recovery of purchased gas) of $473,218. As discussed in the testimony of Steve Irvine, Staff recommends recovering purchase gas cost entirely through an adjustor mechanism. Staff's revenue requirement represents a $147,406, or 45.24 percent, increase over adjusted test year revenue of $325,812.

Q. How does Staff's recommended revenue requirement compare to Duncan Rural's proposed revenue requirement?

A. Staff and Duncan Rural agree that a $147,406 revenue increase is appropriate. The apparent disparity between Staff and the Cooperative regarding the revenue requirement and test year revenues is in form only. The apparent disparity is due to a difference in the base cost of gas used to calculate revenue. Staff's revenues exclude all revenues collected to recover purchased gas cost, i.e., the base cost of gas is zero, while the Cooperative's revenues reflect recovery of purchased gas cost. This difference is a matter of classification and has no impact on the revenues the Cooperative can ultimately recover. The $147,406 recommended revenue increase represents a 45.24 percent increase over Staff's adjusted test year margin revenue and a 22.70 percent increase over Duncan Rural's test year revenue of $649,377, which includes recovery of gas costs. The 22.70 percent calculation is more representative of the increase to customer bills since customers would continue to pay the cost of purchased gas under either Staff's recommendation or the Cooperative's proposal.

Q. What times interest earned ratio ("TIER") and debt service coverage ("DSC") would result from Staff's recommended revenue?

A. Staff's recommended revenue would provide Duncan Rural with a 3.38 TIER and a 1.64 DSC.

Q. What TIER and DSC would result from Duncan Rural's proposed revenues as filed?

A. Duncan Rural's application shows that its proposed revenue would provide a 2.00 TIER and a 1.38 DSC.

Q. Why do Staff's TIER and DSC differ from Duncan Rural's TIER and DSC?

A. The reasons for the differing TIER and DSC results are: (1) differing amounts of debt recognized; (2) differing recommended operating margins; and (3) differing TIER and DSC calculation methods.

Q. How do Staff and Duncan Rural calculate TIER?

A. Staff calculates TIER by dividing the sum of operating income and income tax expense by interest expense on long term debt. Duncan Rural calculates TIER by dividing the sum of interest expense and net income/loss by interest expense on long term debt.

Q. How do Staff and Duncan Rural calculate DSC?

A. Staff calculates DSC by taking the sum of operating income, depreciation and amortization and income tax expense divided by the sum of interest expense on long term debt and repayment of principle. Duncan Rural calculates DSC by taking the sum of net income/loss, depreciation and interest expense on long term debt divided by the sum of interest expense on long term debt and repayment of principle.

Q. What do the times interest earned and the debt service coverage ratios represent?

A. TIER represents the number of times operating income covers interest expense on long-term debt. A TIER greater than 1.0 means that operating income is greater than interest expense. DSC represents the number of times internally generated cash covers required principal and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating cash flow is sufficient to cover debt obligations.

Q. Does Duncan Rural's lender have debt covenants for TIER and DSC?

A. No. Duncan Rural's lender, who is DVEC, does not have TIER and DSC ratio requirements.

Summary of Staff's Adjustments and Recommendations

Operating

Q. Please summarize the rate base and operating income adjustments addressed in your testimony.

A. My testimony addresses the following issues:

Prepayments – This adjustment decreases rate base by $14,351 to eliminate the Cooperative's selective recognition of prepayments and the exclusion of other cash working capital components.

Revenue Annualization – This adjustment increases revenues by $2,574 to reflect revenues at the Test-Year end customer level.

Base Cost of Gas and Fuel Adjustor – This adjustment decreases operating revenue by a total of $325,142 to remove all revenue that represents recovery of gas costs. Additionally, this adjustment removes $325,260 for purchased gas costs from expenses. The removal of gas costs from expenses and removal of recovery of gas costs from revenue reflects Staff's recommendation to flow all purchased gas expense through the fuel adjustor mechanism.

ACC Assessment – This adjustment removes $997 from revenue and $1,472 from expense included in the Cooperative's application related to the ACC assessment to reflect Staff's recommendation that the ACC Assessment be treated as a pass-through item.

Rate Case Expense – This adjustment decreases operating expenses by $4,851 to recognize a normalized level of rate case expense by distributing the Cooperative's estimated cost over three years.

Income Tax Expense – This adjustment increases test year operating expenses by $7,445 to reflect application of statutory state and federal income tax rates to Staff's calculated taxable income.

Non-Operating

Interest Expense on Long-term Debt – This non-operating income adjustment decreases interest expense on long-term debt by $8,019 to reflect application of Staff's interest rates to Staff recommended level of long-term debt.

Other Recommendations

DVEC Debt – Staff recommends that the Commission order Duncan Rural to refrain from obtaining any new debt from DVEC without obtaining prior authorization from the Commission.

Capital Structure – Staff recommends that the Commission order the Cooperative to follow Staff's recommended schedule to improve its equity position by 5 percent each year until patronage equity equals 30 percent of total capital.

Schedules

Q. Have you prepared any schedules to support Staff's testimony?

A. Yes. I prepared fourteen schedules (DTZ-1 to DTZ-14) to support Staff's revenue requirement analysis.

Rate Base

Fair Value Rate Base

Q. Did the Cooperative prepare a schedule showing the elements of Reconstruction Cost New Rate Base ("RCND")?

A. No. The Cooperative stipulated that the Commission may use its "original cost less depreciation rate base for purposes of determining a return on fair value in this Application."

Rate Base Summary

Q. Please summarize Staff's adjustments to Duncan Rural's rate base shown on Schedules DTZ-3 and DTZ-4.

A. Staff made one adjustment to Duncan Rural's proposed rate base resulting in a net decrease of $14,351 from $772,408 to $758,057. Staff's adjustment is discussed below.

Rate Base Adjustment No. 1 – Working Capital, Prepayments

Q. What is the purpose of recognizing a cash working capital component in the rate base calculation?

A. In general, cash working capital reflects the amount of cash that the utility principals either provide or receive from customers for daily operations. If the principals provide cash the cash working capital allowance is an addition to rate base, and if the cash is received from customers, then cash working capital is treated as a deduction from rate base.

Q. What is the best method to determine a cash working capital allowance?

A. Performing a lead-lag study is the most reliable method for calculating cash working capital. A lead-lag study measures the revenue dollar lag days between the provision of service and the collection of revenue and the expense dollar lag days between the provision of service and the payment of bills. If the revenue dollar lag days exceed the expense dollar lag days the cash working capital allowance is an increase to rate base, and if the expense dollar lag days exceed the revenue dollar lag days the cash working capital allowance is a deduction from rate base.

Q. Did Duncan Rural perform a lead-lag study?

A. No, it did not.

Q. If the Cooperative had performed a lead-lag study could it have shown that the cash working capital allowance is negative?

A. Yes, it could have. Some of the Cooperative's largest expenses such as interest, property and income taxes are collected from customers prior to the payment due dates. This provides significant support to the possibility that if a lead-lag study had been conducted that the resulting cash working capital allowance would have been a deduction from rate base.

Q. Does Duncan Rural's proposal to include the cost of a prepaid insurance premium in the Working Capital calculation represent an inequitable, selective adjustment to increase rate base?

A. Yes. The Cooperative chose not to conduct a lead-lag study and, accordingly, omitted a major component of cash working capital analysis. A lead-lag study is recognized as the most accurate method to calculate cash working capital. It is inequitable to ignore a major component of the cash working capital analysis and selectively recognize other components.

Q. Is there any significance to the allowance or disallowance of prepayments or any other component to cash working capital to Duncan Rural's revenue requirement?

A. No. The members of the cooperative are also the owners. The members' goal is to obtain the best service at the lowest rate possible. Consequently, the primary revenue requirement considerations are the provision of adequate cash flow to meet payment obligations and maintenance of an appropriate capital structure. Therefore, the Cooperative appropriately chose not to incur the expense of a lead-lag study. However, the inclusion of selective cash working capital components in rate base is inappropriate.

Q. What is the amount and nature of the Prepayment that the Cooperative is proposing to include in rate base?

A. The prepayment is the annual renewal cost of an insurance premium in the amount of $14,351.

Q. What is Staff recommending for Prepayments?

A. Staff recommends removal of $14,351 in Prepayments from Working Capital as shown on Schedules DTZ-4 and DTZ-5.

Operating Income

Operating Income Summary

Q. What are the results of Staff's analysis of Test Year revenues, expenses and operating income?

A. As shown on Schedules DTZ-6 and DTZ-7 Staff's analysis resulted in Test Year revenues of $325,812, expenses of $372,174 and an operating loss of $46,394.

Operating Income Adjustment No. 1 – Revenue Annualization

Q. Did the Cooperative annualize both revenues and expenses?

A. No. The Cooperative annualized salary and wage expense but made no adjustment to annualize revenues.

Q. What is the purpose of a revenue and expense annualization?

A. A revenue and expense annualization is made to achieve matching with the test-year end rate base measurement date.

Q. What customer classes did Staff annualize?

A. Staff annualized only the "250 cfh and Below" customer class. The "Above 250 cfh to 425 cfh" was not annualized due to the relatively large number of seasonal customers within the class. The "Above 425cfh to 1,000 cfh" was not annualized because the lone customer decrease was due to that customer moving to another customer class.

Q. What method did Staff use to annualize revenues for the "250 cfh and Below" customer class?

A. First, Staff calculated the average customer bill for each respective month of the test year. Second, Staff multiplied the average customer bill for each month to the difference between the test-year end customer count and the customer count for each respective month to determine the additional revenue that would have resulted each month had the test-year end customer level existed throughout the year. Finally, Staff totaled the monthly calculations to determine the total annualization adjustment. Staff's annualization adjustment adds $2,574 to Test Year revenue as shown on Schedule DTZ-8.

Q. Is it necessary to annualize purchased gas expense to match the annualization of revenues?

A. Annualization of purchase gas expense is not necessary as long as the base cost of gas is set at $0.00 and purchased gas cost is recovered through the fuel adjustor mechanism as recommended by Staff and discussed in the testimony of Staff witness Steve Irvine.

Q. Is it necessary to annualize any other expenses to match the annualization of revenues?

A. No. In response to a data request, the Cooperative indicated there were no other expenses that varied significantly with usage. Additionally, Staff performed an analysis that calculated the increase and decrease in the number of customers for the past three years and compared those numbers to the increase or decrease in expenses for the same years. That analysis showed that no expense varied significantly with the change in the number of customers.

Q. What is Staff recommending?

A. Staff recommends increasing revenues by $2,574 as shown on Schedules DTZ-7 and DTZ-8.

Operating Income Adjustment No. 2 – Base Cost of Gas and Fuel Adjustor

Q. Explain the purpose of classifying Total Revenue into two components as shown in Schedules DTZ-9.

A. The purpose is to show separately the portion of revenue that represents costs that flow through the fuel adjustor mechanism.

Q. What revenue did Duncan Rural recover through its base cost of gas rate and its fuel adjustor mechanism?

A. The Cooperative collected $206,689 (574,136 therms x $0.36) from its base cost of gas rate and $118,453 from its fuel adjustor rate for a total of $325,142.

Q. What purchased gas expense did the Cooperative incur during the Test Year?

A. Duncan Rural incurred $325,260 in purchased gas expense during the Test Year.

Q. What ratemaking treatment does Staff recommend for the purchased gas expense?

A. Staff recommends removing all purchased gas expense from the margin revenue requirement and providing for the recovery of all purchased gas cost through a fuel adjustor mechanism, as discussed in the testimony of Staff witness Steve Irvine.

Q. What is Staff recommending?

A. Staff recommends removing the entire $325,260 purchased gas cost from operating expenses and the entire $325,142 operating revenue as shown on Schedules DTZ-7 and DTZ-9.

Operating Income Adjustment No. 3 – ACC Gross Revenue Assessment

Q. What is the Cooperative proposing for the ACC assessment?

A. The Cooperative included $997 in operating revenue and $1,472 in operating expense for the ACC assessment.

Q. Does Staff agree that the ACC Assessment be included in operating expenses?

A. No, the assessment should not be included in the cost of service and should be recovered through a bill add-on similar to that recommended for Arizona Electric Power

Cooperative, Inc. ("AEPCO") in Decision No. 58405[4] which states that "*The gross revenue tax will in the future be recovered through a bill add-on.*"

Q. What is Staff recommending?

A. Staff recommends decreasing operating revenue by $997 and operating expense by $1,472 to remove the effects of the ACC assessment as shown on Schedules DTZ-7 and DTZ-10.

Operating Income Adjustment No. 4 – Rate Case Expense

Q. What is the Cooperative proposing for Rate Case Expense?

A. Duncan Rural proposed $16,426 for rate case expense. The Company's proposed amount represents distribution of its estimated total rate case expense of $32,852 over two years.

Q. Does Staff agree with the Cooperative proposed rate case expense?

A. No. The history of Duncan Rural suggests that the Cooperative will not file another rate case within two years. Staff's revenue recommendation in this case is based on the assumption of a three-year interval between this and the Cooperative's next rate filing. Accordingly, Staff recommends a normalized rate case expense of $10,951 that would provide recovery of the Cooperative's estimated amount over three years.

Q. What is Staff recommending?

A. Staff recommends decreasing rate case expense by $4,851 to reflect Staff's normalized amount as shown on Schedules DTZ-7 and DTZ-11.

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[4] At page 17, footnote no. 9.

Operating Income Adjustment No. 5 – Test Year Income Tax Expense

Q. What is the Cooperative proposing for test year income tax expense?

A. The Company is proposing test year income tax expense of negative $30,460.

Q. Does Staff agree with the Cooperative's income tax amount?

A. No. Differences between the Staff's and the Cooperative's test year operating revenues and expenses result in different taxable incomes and income taxes. Staff calculated income tax expense by applying the statutory State and Federal income tax rates to its taxable income as shown in Schedule DTZ-2.

Q. What is Staff recommending?

A. Staff recommends increasing test year income tax expense by $7,445 to negative $23,015 as shown on Schedule DTZ-7 and DTZ-12.

Income Adjustment No. 6 (Non-Operating) – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. Duncan Rural is proposing $31,112 for Interest Expense on Long-term Debt as shown on Schedule DTZ-13. The Cooperative's proposed interest expense is composed of $14,973 for existing debt and a $16,139 pro forma adjustment to reflect its proposed conversion of accounts payable to long-term as discussed below. Duncan Rural proposed a loan amount of $268,988 and used an interest rate of 6 percent to calculate interest expense on the proposed debt ($268,988 X 6% = $16,139).

Q. Did Staff make an independent assessment of the Cooperative's Interest Expense on Long-term Debt?

A. Yes. Staff calculated $23,093 as the Cooperative's interest expense on long-term debt. Staff's calculation includes $14,087 for existing debt and a $9,006 pro forma allowance to reflect Staff's recommendation to authorize a $330,484 conversion of accounts payable to long term debt.

Q. How did Staff calculate Duncan Rural's actual and pro forma interest expense?

A. Staff calculated interest expense on existing loans by applying the current[5] 2.725 percent rate to the test-year end balance of Duncan Rural's three existing long-term debt notes. Staff calculated a pro forma annual interest expense related to the recommended $330,484 conversion of accounts payable to long-term debt by applying 2.725 percent to that amount. (Refer to Schedule DTZ-13.)

Q. What adjustment did Staff make to Interest Expense on Long-term Debt?

A. Staff decreased Interest Expense on Long-term Debt by $8,019 as shown on Schedules DTZ-7 and DTZ-13.

IV. COMPLIANCE

Short-term Debt

Q. What does Arizona Revised Statute ("ARS") §40-302.D state concerning the maximum amount of short-term debt that a regulated utility can borrow without prior Commission approval?

A. It states:

> *A public service corporation may issue notes, not exceeding seven percent of total capitalization if operating revenues exceed two hundred fifty*

[5] September 2, 2005

thousand dollars, for proper purposes and not in violation of law payable at periods of not more than twelve months after date of issuance, without consent of the commission, but no such note shall, wholly or in part, be refunded by any issue of stocks or stock certificates, bonds, notes or any other evidence of indebtedness without consent of the commission.

Q. Is Duncan Rural required to obtain Commission authorization to issue notes for the amount of short-term debt it has accepted from DVEC?

A. Yes. Table 1 shows Duncan Rural's total capitalization, seven percent of total capitalization, cash advances (classified by Duncan Rural as accounts payable) from DVEC and the excess of accounts payable over seven percent of total capital for the years ended December 31, 2002, 2003, and 2004.

Table 1

	2002	2003	2004
Total Capital[6]	$528,653	$463,828	$368,884
Seven Percent of Total Capital	$37,006	$32,468	$25,822
Accounts Payable (DVEC)	$174,629	$311,718	$443,584
Excess	$137,623	$279,250	$417,762

Although Duncan Rural has not issued any "notes" because its parent has not required formal documentation of the borrowed funds, the substantive effect of the Cooperative's actions is as if it had issued notes without authorization.

[6] Obtained from Duncan Rural's R.U.S. form 7

Q. Has Duncan Rural obtained significant debt from DVEC in the past without obtaining Commission authorization?

A. Yes. Duncan Rural requested, and was approved for, similar financing authorization in its prior rate case (Decision No. 64869, dated June 5, 2002). In that case Duncan Rural requested authorization to convert $400,000 of accounts payable due to DVEC into long term debt. The application in that case stated that DVEC had advanced funds to Duncan Rural over the previous six years for improvements to the gas distribution system and working capital. Duncan Rural did not seek Commission approval prior to obtaining those advances.

Q. What is Staff recommending?

A. Staff recommends that the Commission order Duncan Rural to refrain from obtaining any new debt from DVEC without obtaining prior authorization from the Commission.

V. FINANCING APPLICATION

Q. Please provide a brief background for the financing application?

A. Duncan Rural filed a financing application (Docket No. G-02528A-03-0205) on April 4, 2003, requesting authorization to incur $400,000 of long-term debt to repay DVEC for advances intended to pay for plant improvements and to provide working capital for operations. Immediately after the application was filed Duncan Rural called the Chief of the Financial and Regulatory Analysis section at the Commission and requested that Staff not process the application until Duncan Rural filed a permanent rate increase application. Duncan Rural made this request as its existing rates were not sufficient to meet the debt service requirements on the proposed debt. Duncan Rural requested consolidation of the financing application and its current rate application as part of its current rate proceeding.

Duncan Rural also changed the amount of debt requested from $400,000 to $268,988 in order to not have total debt exceed its rate base.

Q. What is the Cooperative requesting in its financing application?

A. Duncan Rural is requesting that the Commission approve as long-term debt $268,988 of the $443,584 of cash advanced to or on its behalf by DVEC over approximately the past four years.

Q. How are the advanced funds recorded on Duncan Rural's books?

A. The Cooperative has recorded these obligations as accounts payable.

Q. How has Duncan Rural used the advanced funds?

A. Duncan Rural states in its application that funds were advanced by DVEC in order to allow it to pay operating expenses and to fund plant additions. The proposed refinancing would formalize the past due accounts payable by converting $268,988 of accounts payable owed to DVEC to long-term debt owed to DVEC.

Q. What were the accounts payable balances that Duncan Rural owed to DVEC ("DVEC Accounts Payable") for the years 2002, 2003, and 2004?

A. The DVEC Accounts Payable balances for the years ended December 31, 2002, 2003, and 2004, were $174,629, $311,718, and $443,584, respectively. Duncan Rural's net losses the years 2002, 2003 and 2004 in the amounts of $22,423, $18,859 and $49,639, respectively, provided no opportunity to it to repay the cash advances from DVEC causing the outstanding balance to grow.

Q. What opportunity has been afforded Duncan Rural by accepting cash advances from DVEC?

A. The cash advances have provided working capital necessary for Duncan Rural to meet its other financial obligations while allowing the Cooperative to postpone or circumvent regulatory filings for rates and financing despite continuing losses. Duncan Rural has indulged in this convenience for at least 10 years.

Q. What have been the changes in Duncan Rural's accounts payable and long-term debt balances since 2002?

A. The changes are shown in Table 2.

Table 2

Year	Accounts Payable Beginning Balance	Increase or Decrease	Accounts Payable Ending Balance	Long-term Debt Ending Balance
2001	$445,061	$35,724	$480,785	$218,148
2002	$480,785	($306,156)	$174,629	$572,829
2003	$174,629	$137,089	$311,718	$515,563
2004	$311,718	$131,866	$443,584	$472,858

Q. What caused the accounts payable balance to decrease in 2002?

A. In Decision No. 64869 the Commission authorized the Cooperative to convert $400,000 of accounts payable due to DVEC to long term debt. Thus, the $306,156 reduction in the accounts payable balance resulted from a $400,000 conversion to long-term debt and incremental accounts payable of $93,844. Making allowance for the conversion of accounts payable to long-term debt, Table 2 shows that the Cooperative's accounts payable obligations have grown each year.

Q. Did the Commission authorize rates in DVEC's previous rate case that provided a positive operating margin?

A. No. In Decision No. 67433, the Commission authorized rates to provide an operating loss for DVEC. Operating losses wouldn't likely generate sufficient cash flow from operations for DVEC to advance cash to Duncan Rural.

Q. What is the source of the cash that DVEC uses to lend to Duncan Rural?

A. DVEC received \$1.3 million[7] in cash from a Phelps Dodge contract termination.

Q. For what purpose was the \$1.3 million originally intended?

A. The \$1.3 million was originally intended to subsidize DVEC operations and allow DVEC to gradually increase rates until such time as DVEC could break-even.[8] It mitigates the rate shock that DVEC customers would have experienced in order to recover from the effect of the Phelps Dodge contract termination.

Q. What is the implication for DVEC and its customers from the cash advanced to Duncan Rural?

A. DVEC has less immediate cash for its own operating requirements. In the event a portion of the advances is not repaid, DVEC's customers would be harmed. Delays in repayment could accelerate and increase the magnitude of DVEC rate adjustments.

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[7] According to Decision No. 67433 (page 3, paragraph 10), "Approximately 97 percent of DVEC 1997 revenues came from one large industrial customer, Phelps Dodge Corporation ("Phelps Dodge"). In 1993, Phelps Dodge notified DVEC that it was terminating its power supply contract as of November 1998. Phelps Dodge agreed to pay DVEC \$1.3 million as a result of terminating the contract . . . With the loss of the Phelps Dodge contract, DVEC no longer had sufficient revenues to cover its operating expenses and experienced negative margins."

[8] Decision No. 67433, page 4, beginning at line 12

Q. Should the practice of DVEC lending to Duncan Rural through the Accounts Payable process continue?

A. No. Duncan Rural has had a chronic and unhealthy financial dependence on DVEC to pay a substantial portion of its operating expenses. This dependence has resulted in Duncan Rural not taking prompt action to apply for necessary rate increases when it experienced cash flow problems. It has also led to a "snow balling" effect in which the accounts payable balance increased by $280,783 in approximately two years (i.e., from $174,629 at January 1, 2003 to $455,352 at February 28, 2005).

Q. How much of the $443,584 test-year end accounts payable balance did Duncan Rural invest in plant?

A. Staff's audit revealed that Duncan Rural used $330,484 of cash advances for plant improvements.

Q Does the amount of cash advances used for capital improvements affect the amount that should be considered for conversion to long-term debt?

A. Yes. Since capital improvements will continue to provide benefits to Duncan Rural's ratepayers, advances used for capital improvement should be eligible for consideration for conversion.

Q. How does the amount of cash advances used for capital improvements compare to the amount of cash advances the Cooperative requests for authorization to convert to long term debt?

A. The cash advances used for capital improvements exceeds the requested debt authorization by $61,496 ($330,484 - $268,988).

Q. **Is Staff recommending conversion of the entire $330,484 of cash advances that Duncan Rural used for capital improvements to long-term debt?**

A. Yes. Staff recommends authorization for Duncan Rural to convert $330,484 of obligations incurred as cash advances from DVEC to long-term debt.

Q. **What are the proposed terms of the loan?**

A. The proposed loan from DVEC would be amortized over a period of 25 years and would have a variable interest rate equal to AEPCO's variable interest rate earned on funds with repayments over 25 years.

Q. **What is the remaining accounts payable balance after conversion of $330,484 to long-term debt?**

A. The remaining balance is $124,868 ($455,352 - $330,484).

Q. **Is it appropriate to convert amounts borrowed to cover operating expenses to long-term debt?**

A. No. When operating expenses are converted into long-term debt a cost shift occurs between periods resulting in customers in later periods paying for the benefits received by customers in an earlier period.

Q. **How does Duncan Rural propose to repay the balance of the DVEC accounts payable?**

A. The Cooperative proposes to pay the balance when funds are available or to convert the balance into long-term debt.[9]

[9] Direct Testimony of John V. Wallace, page 18, beginning at line 8.

Summary of Staff's Financing Application Recommendations

Q. Please provide a summary of Staff's recommendations regarding Duncan Rural's request to convert $268,988 of cash advances from DVEC to long-term Debt.

A. Staff recommends authorizing Duncan Rural to convert $330,484 of obligations incurred as cash advances from DVEC to a 25-year note payable at a variable interest rate equal to AEPCO's variable interest rate earned on funds.

VI. CAPITAL STRUCTURE

Q. What was Duncan Rural's actual Test Year-end capital structure?

A. Duncan Rural's actual Test Year-end capital structure consisted of 142.07 percent debt and negative 42.07 percent patronage equity as shown on the Cooperative's Schedule D-1.

Q. How does Duncan Rural's capital structure compare to other cooperatives' capital structures?

A. Duncan Rural's capital structure is more leveraged than any of the cooperatives in Staff's sample. None of the sample cooperatives have a negative equity position. Schedule DTZ-14 presents a sample of cooperatives' capital structures at December 31, 2004. The average capital structure of the cooperatives is composed of 68.2 percent debt and 31.8 percent patronage equity as opposed to the Cooperative's capital structure composed of 142.07 percent debt and a negative 42.07 percent patronage equity.

Q. Is Staff concerned with Duncan Rural's actual Test Year-end capital structure?

A. Yes. Duncan Rural's capital structure is highly leveraged as it has remained for several years. The Cooperative's capital structure: (1) restricts its ability to obtain additional capital, (2) may result in less favorable terms for future financings and (3) places upward pressure on rates to cover debt service obligations.

Q. Has the Commission shown concern with highly leveraged cooperatives?

A. Yes. The Commission ordered AEPCO (Decision No. 64227, dated November 29, 2001) and Southwest Transmission Cooperative ("SWTCO") (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve their patronage equity positions. In addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with the Commission (Decision No. 67412, dated November 2, 2004). As discussed previously, highly leveraged capital structures present potentially negative consequences.

VII. EQUITY IMPROVEMENT PLAN

Q. What approach does Staff recommend to improve Duncan Rural's capital structure?

A. Staff recommends that Duncan Rural develop a capital plan designed to improve its capital structure to at least 30 percent equity within a reasonable time frame. Staff recommends that Duncan Rural be ordered to file a schedule detailing its current capital structure within 90 days of the end of the calendar year, starting with 2005, for each year until its next rate case filing. Staff recommends that in the event Duncan Rural does not improve its equity position by a cumulative average of 5 percent (using its December 31, 2005 position as a base) at the end of any calendar year until patronage equity is a minimum of 30 percent of total capital, that the Cooperative be required to file a rate application within 180 days of the end of the calendar year that the 5 percent cumulative average increase in patronage equity is not achieved. However, Duncan Rural may be granted a waiver from filing a rate application if it provides a written explanation as to why it did not achieve its equity goal and it can demonstrate to Staff's satisfaction that it is likely that it will achieve the cumulative equity goal in Staff's recommendation within a reasonable timeframe without any rate adjustment. Such demonstration should be provided within 90 days of the end of the calendar year. In no instance shall Duncan

Rural fail to achieve its cumulative equity improvement goal for three consecutive years without filing a rate application. Staff also recommends that the Commission prohibit distribution of patronage dividends until Duncan Rural has achieved a capital structure composed of at least 20 percent patronage equity.

Q. Is Staff's position that an optimal capital structure for the Applicant is composed of 70 percent debt and 30 percent equity?

A. No. Staff considers that a capital structure for the Applicant composed of 30 percent equity and 70 percent debt is not optimal, but a minimum capital structure that Duncan Rural should target to achieve.

Q. Is Staff's recommended revenue sufficient to improve Duncan Rural's equity position in a reasonable timeframe?

A. Yes, Staff's recommended revenue provides Duncan Rural with a positive operating margin that supports the recommended growth in patronage equity.

Q. Please summarize Staff's recommendations concerning Duncan Rural's equity position.

A. Staff recommends that the Commission order Duncan Rural to follow Staff's equity recommendation. Staff also recommends that the Commission order the Applicant to file a rate application within 180 days of the end of any calendar year that Duncan Rural is not able to meet the cumulative patronage equity level specified in Staff's proposed plan. However, Duncan Rural may be granted a waiver from filing a rate application if it can demonstrate to Staff's satisfaction that it is likely that the Applicant will achieve the cumulative increase in patronage equity level in Staff's plan within a reasonable timeframe without any rate adjustment. Such demonstration should be provided within 90 days of the end of the calendar year. In no instance shall the Applicant fail to achieve Staff's equity plan for three consecutive years without filing a rate application.

Staff also recommends that the Commission restrict the distribution of future patronage dividends by Duncan Rural until it has achieved a capital structure composed of at least 20 percent patronage equity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Schedule DTZ-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST
1	Adjusted Operating Income (Loss)	$	(46,968)	$	(46,394)
2	Depreciation and Amortization	$	49,645	$	49,645
3	Long-term Debt Interest Expense	$	31,112	$	23,093
4	Income Tax Expense		N/A	$	12,331
5	Principal Repayment	$	45,303	$	54,661
6	Recommended Increase in Operating Margin	$	108,814	$	112,060
7	Gross Revenue Conversion Factor		1.3514		1.3154
8a	**Recommended Increase in Operating Revenue**	$	147,406	$	**147,406**
8b	**Percent Increase (Line 8a / Line 9) - Per Staff**		N/A		**22.70%**
8c	Percent Increase (Line 8a / Line 9) - Per Coop		22.70%		N/A
9	Adjusted Test Year Operating Revenue	$	649,377	$	325,812
10	**Recommended Annual Operating Revenue**	$	796,783	$	**473,219**
11a	**Recommended Operating Margin**	$	61,846	$	**65,665**
11b	Recommended Net Margin	$	30,845	$	42,682
12a	**Recommended Operating TIER (L11a+L4)/L3 - Per Staff**		N/A		**3.38**
12b	Recommended Net TIER Per Coop		2.00		N/A
13a	**Recommended DSC (L11a+L2+L4)/(L3+L5) - Per Staff**		N/A		**1.64**
13b	Recommended DSC Per Coop		1.38		N/A
14	**Adjusted Rate Base**	$	772,408	$	**758,057**
15	Rate of Return (L10 / L14)		8.01%		8.66%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules DTZ-2, DTZ-8

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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	Calculation of Gross Revenue Conversion Factor:				
1	Billings	1.000000			
2	Uncollectible Factor	0.000000			
3	Revenues	1.000000			
4	Less: Combined Federal and State Tax Rate (Line 12)	0.239787			
5	Subtotal (L3 - L4)	0.7602			
6	**Revenue Conversion Factor (L1 / L5)**	**1.31542**			
	Calculation of Effective Tax Rate:				
7	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
8	Arizona State Income Tax Rate	6.9680%			
9	Federal Taxable Income (L7 - L8)	93.0320%			
10	Applicable Federal Income Tax Rate (Line 34)	18.2848%			
11	Effective Federal Income Tax Rate (L9 x L10)	17.0107%			
12	Combined Federal and State Income Tax Rate (L8 +L11)	23.9787%			
13	Required Operating Income (Schedule DTZ-1, Line 5)	$ 65,665			
14	AdjustedTest Year Operating Income (Loss) (Schedule DTZ-10, Line 16)	$ (46,394)			
15	Required Increase in Operating Income (L13 - L14)		$ 112,060		
16	Income Taxes on Recommended Revenue (Col. (D), L33)	$ 12,331			
17	Income Taxes on Test Year Revenue (Col. (B), L33)	$ (23,015)			
18	Required Increase in Revenue to Provide for Income Taxes (L16 -L17)		$ 35,346		
19	Total Required Increase in Revenue (L15 + L18)		$ 147,406		
	Calculation of Income Tax:	Test Year		Staff Recommended	
20	Revenue (Schedule DTZ-9, Columns C and E)	$ 325,812	$ -	$ 473,218	
21	Less: Operating Expenses Excluding Income Taxes	$ 395,222		$ 395,222	
22	Less: Synchronized Interest (L37)	$ 20,657		$ 20,657	
23	Arizona Taxable Income (L20 - L21 - L22)	$ (90,066)		$ 57,340	
24	Arizona State Income Tax Rate	6.968%		6.968%	
25	Arizona Income Tax (L23 x L24)		$ (6,276)		$ 3,995
26	Federal Taxable Income (L23 - L25)	$ (83,791)		$ 53,344	
27	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ (7,500)		$ 7,500	
28	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ (6,250)		$ 836	
29	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ (2,989)		$ -	
30	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -		$ -	
31	Federal Tax on Fifth Income Bracket ($335,001 - $10,000,000) @ 34%	$ -		$ -	
32	Total Federal Income Tax		$ (16,739)		$ 8,336
33	Combined Federal and State Income Tax (L25 + L32)		$ (23,015)		$ 12,331
34	Applicable Federal Income Tax Rate [Col. (D), L32 - Col. (B), L32] / [Col. (C), L26 - Col. (A), L26]				18.2848%
	Calculation of Interest Synchronization:				
35	Rate Base (Schedule DTZ-3, Col. (C), Line 13	$ 758,057			
36	Weighted Average Cost of Debt	2.73%			
37	Synchronized Interest (L35 x L37)	$ 20,657			

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Schedule DTZ-3

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 1,342,397	$ -	$ 1,342,397
2	Less: Acc Depreciation & Amortization	(572,264)	-	(572,264)
3	Net Plant in Service	$ 770,133	$ -	$ 770,133
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Deferred Taxes	$ 19,554	$ -	$ 19,554
9	Customer Deposits	$ 20,064	$ -	$ 20,064
	ADD:			
10	Cash Working Capital	$ -	$ -	$ -
11	Materials and Supplies	$ 27,542	$ -	$ 27,542
12	Prepayments	$ 14,351	$ (14,351)	$ -
13	**Total Rate Base**	$ 772,408	$ (14,351)	$ 758,057

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Schedule DTZ-4
Column [C]: Column [A] + Column [B]

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Schedule DTZ-4

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] PREPAYMENTS ADJ No. 1	[C] STAFF ADJUSTED
	PLANT IN SERVICE:			
1	Intangible Plant	$ -	$ -	$ -
2	Land & Land Rights	-	-	-
3	Mains	725,872	-	725,872
4	Mains - Anodes	143,207	-	143,207
5	City Gates	27,130	-	27,130
6	Services	191,962	-	191,962
7	Meters, Regulators & Install	209,535	-	209,535
8	Land & Land Rights	-	-	-
9	Structures & Improvements	-	-	-
10	Office Furniture & Improvements	2,000	-	2,000
11	Transportation Equipment	-	-	-
12	Stores Equipment	1,413	-	1,413
13	Tools & Shop Equipment	22,553	-	22,553
14	Laboratory Equipment	13,369	-	13,369
15	Power Operated Equipment	1,116	-	1,116
16	Communication Equipment	788	-	788
17	Miscellaneous Equipment	3,452	-	3,452
18	Total Plant in Service	$ 1,342,397	$ -	$ 1,342,397
19	Less: Accumulated Depreciation	$ (572,264)	-	$ (572,264)
20	Less: Accumulated Amortization	-	-	-
21	Total Accumulated Depreciation & Amortization	$ (572,264)	$ -	$ (572,264)
22	Net Plant in Service	$ 770,133	$ -	$ 770,133
	LESS:			
23	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
24	Contributions in Aid of Construction (CIAC)	-	-	-
25	Less: Accumulated Amortization	-	-	-
26	Net CIAC	$ -	$ -	$ -
27	Deferred Taxes	$ 19,554	$ -	$ 19,554
28	Customer Deposits	$ 20,064		$ 20,064
	ADD:			
29	Construction Work in Progress	$ -	-	$ -
30	Materials and Supplies	27,542	-	27,542
31	Prepayments	14,351	(14,351)	-
32	**Total Rate Base**	$ 772,408	$ (14,351)	$ 758,057

ADJ No.		References
1	Prepayments	Schedule DTZ-5

Duncan Rural Services Corporation
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Test Year Ended December 31, 2004

Schedule DTZ-5

RATE BASE ADJUSTMENT NO. 2 - WORKING CAPITAL, PREPAYMENTS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Cash Working Capital	$ -	$ -	$ -
2	Materials and Supplies	$ 27,542	$ -	$ 27,542
3	Prepayments	$ 14,351	$ (14,351)	$ -
4	**Total Working Capital**	**$ 41,893**	**$ (14,351)**	**$ 27,542**

5 References:
6 Column A: Cooperative Schedule B-1, Page 1
7 Column B: Testimony, DTZ, Schedule DTZ-3
8 Column C: Column [A] + Column [B]

Duncan Rural Services Corporation
Docket No. G-02528A-05-0314
Test Year Ended December 31, 2004

Schedule DTZ-6

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	***REVENUES:***					
2	Sales Revenue of Gas - Base Cost of Gas	$ 206,689	$ (206,689)	$ -	$ -	$ -
3	Sales Revenue of Gas - Fuel Adjustor	$ 118,453	$ (118,453)	$ -	$ -	$ -
4	Sales Revenue of Gas - Non Base Cost of Gas	$ 319,025	$ 1,577	$ 320,602	$ 147,406	$ 468,008
5	Other Operating Revenue	$ 5,210	$ -	$ 5,210	$ -	$ 5,210
6	**Total Revenues**	$ 649,377	$ (323,565)	$ 325,812	$ 147,406	$ 473,218
7	***EXPENSES:***					
8	Gas Purchases	$ 325,260	$ (325,260)	$ -	$ -	$ -
9	***Distribution Expense - Operations***					
10	Supervision	$ 950	$ -	$ 950	$ -	$ 950
11	Mains & Services	$ 110,026	$ -	$ 110,026	$ -	$ 110,026
12	Measuring & Regulation Stations	$ 13,753	$ -	$ 13,753	$ -	$ 13,753
13	Meters & House Regulators	$ 20,214	$ -	$ 20,214	$ -	$ 20,214
14	Other Expenses	$ 3,116	$ -	$ 3,116	$ -	$ 3,116
15	Rents	$ 6,039	$ -	$ 6,039	$ -	$ 6,039
16	***Total Distribution Expense-Operations***	$ 154,098	$ -	$ 154,098	$ -	$ 154,098
17	***Distribution Expense - Maintenance***					
18	Maintenance-Supervision	$ -	$ -	$ -	$ -	$ -
19	Maintenance-Mains & Services	$ 46,098	$ -	$ 46,098	$ -	$ 46,098
20	Maintenance-Measuring & Regulation Stations	$ -	$ -	$ -	$ -	$ -
21	Maintenance-Services	$ -	$ -	$ -	$ -	$ -
22	Maintenance-Meters & House Regulators	$ 8,726	$ -	$ 8,726	$ -	$ 8,726
23	Maintenance-Other Equipment	$ -	$ -	$ -	$ -	$ -
24	***Total Distribution Expense-Maintenance***	$ 54,824	$ -	$ 54,824	$ -	$ 54,824
25	***Consumer Accounts Expense***					
26	Meter Reading Expense	$ 25,048	$ -	$ 25,048	$ -	$ 25,048
27	Consumer Expense	$ 30,523	$ -	$ 30,523	$ -	$ 30,523
28	Reserve for Uncollectible Accounts	$ 1,500	$ -	$ 1,500	$ -	$ 1,500
29	Information & Instruction ads	$ 3,058	$ -	$ 3,058	$ -	$ 3,058
30	***Total Consumer Accounts Expense***	$ 60,129	$ -	$ 60,129	$ -	$ 60,129
31	***Administrative and General Expense***					
32	Salaries	$ 8,491	$ -	$ 8,491	$ -	$ 8,491
33	Office Supplies and Expenses	$ 3,606	$ -	$ 3,606	$ -	$ 3,606
34	Outside Services Employed	$ 11,826	$ -	$ 11,826	$ -	$ 11,826
35	Rate Case	$ -	$ -	$ -	$ -	$ -
36	Property Insurance	$ -	$ -	$ -	$ -	$ -
37	Injuries and Damage Ins.	$ 17,568	$ -	$ 17,568	$ -	$ 17,568
38	Regulatory Commission Expense	$ 15,802	$ (6,323)	$ 9,479	$ -	$ 9,479
39	Miscellaneous General	$ 5,550	$ -	$ 5,550	$ -	$ 5,550
40	***Total Administrative and General Expense***	$ 62,843	$ (6,323)	$ 56,520	$ -	$ 56,520
41	Interest Expense - Customer Deposits	$ 367	$ -	$ 367	$ -	$ 367
42	Depreciation and Amortization Expense	$ 49,645	$ -	$ 49,645	$ -	$ 49,645
43	Tax Expense - Property	$ 19,639	$ -	$ 19,639	$ -	$ 19,639
44	Tax Expense - Income Taxes	$ (30,460)	$ 7,445	$ (23,015)	$ 35,346	$ 12,331
45	**Total Operating Expenses**	$ 696,345	$ (324,138)	$ 372,207	$ 35,346	$ 407,553
46	**Operating Margin Before Interest on L.T.- Debt**	$ (46,968)	$ 574	$ (46,394)	$ 112,060	$ 65,665
47	**INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS**	$ 31,112	$ (8,019)	$ 23,093	$ -	$ 23,093
48	**MARGINS (LOSS) AFTER INTEREST EXPENSE**	$ (78,080)	$ 8,593	$ (69,487)	$ 112,060	$ 42,572
49	**NON-OPERATING MARGINS**	$ 110	$ -	$ 110	$ -	$ 110
50	**NET MARGINS (LOSS)**	$ (77,970)	$ 8,593	$ (69,377)	$ 112,060	$ 42,682

References:
Column (A): Cooperative Schedule C-1, Pages 1 and 2
Column (B): Schedule DTZ-8
Column (C): Column (A) + Column (B)
Column (D): Schedules DTZ-1
Column (E): Column (C) + Column (D)

Duncan Rural Services Corporation
Docket No. G-02528A-05-0314
Test Year Ended December 31, 2004

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Revenue Annualization Ref: Sch DTZ-9	[C] ADJ #2 Base Cost of Gas and Fuel Adjustor Ref: Sch DTZ-10	[D] ADJ #3 ACC Assessment Charge Ref: Sch DTZ-11	[E] ADJ #4 Rate Case Expense Ref: Sch DTZ-12	[F] ADJ #5 Income Tax Expense Ref: Sch DTZ-13	[G] ADJ #6 Interest Expense on Long Term Debt Ref: Sch DTZ-14	[H] STAFF ADJUSTED
	REVENUES:								
1	Sales Revenue of Gas - Base Cost of Gas	$ 206,689	$ -	$ (206,689)	$ -	$ -	$ -	$ -	$ -
2	Sales Revenue of Gas - Fuel Adjustor	118,453	-	(118,453)	-	-	-	-	-
3	Sales Revenue of Gas - Margin (Non-gas)	319,025	2,574	-	(997)	-	-	-	320,602
4	Other Operating Revenue	5,210	-	-	-	-	-	-	5,210
5	**Total Revenues**	$ 649,377	$ 2,574	$ (325,142)	$ (997)	$ -	$ -	$ -	$ 325,812
6	***OPERATING EXPENSES:***								
7	Gas Purchases	$ 325,260	$ -	$ (325,260)	$ -	$ -	$ -	$ -	$ -
8	**Distribution Expense - Operations**								
9	Supervision	950	-	-	-	-	-	-	950
10	Mains & Services	110,026	-	-	-	-	-	-	110,026
11	Measuring & Regulation Stations	13,753	-	-	-	-	-	-	13,753
12	Meters & House Regulators	20,214	-	-	-	-	-	-	20,214
13	Other Expenses	3,116	-	-	-	-	-	-	3,116
14	Rents	6,039	-	-	-	-	-	-	6,039
15	**Distribution Expense - Operations**	154,098	-	-	-	-	-	-	154,098
16	**Distribution Expense - Maintenance**								-
17	Supervision	-	-	-	-	-	-	-	-
18	Mains & Services	46,098	-	-	-	-	-	-	46,098
19	Measuring & Regulation Stations	-	-	-	-	-	-	-	-
20	Services	-	-	-	-	-	-	-	-
21	Meters & House Regulators	8,726	-	-	-	-	-	-	8,726
22	Other Equipment	-	-	-	-	-	-	-	-
23	**Distribution Expense - Maintenance**	54,824	-	-	-	-	-	-	54,824
24	**Consumer Accounts Expense**								-
25	Meter Reading Expense	25,048	-	-	-	-	-	-	25,048
26	Consumer Expense	30,523	-	-	-	-	-	-	30,523
27	Reserve for Uncollectible Accounts	1,500	-	-	-	-	-	-	1,500
28	Information & Instruction ads	3,058	-	-	-	-	-	-	3,058
29	**Consumer Accounts Expense**	60,129	-	-	-	-	-	-	60,129
30	**Administrative and General Expense**								-
31	Salaries	8,491	-	-	-	-	-	-	8,491
32	Office Supplies and Expenses	3,606	-	-	-	-	-	-	3,606
33	Outside Services Employed	11,826	-	-	-	-	-	-	11,826
34	Rate Case	-	-	-	-	-	-	-	-
35	Property Insurance	-	-	-	-	-	-	-	-
36	Injuries and Damage Ins.	17,568	-	-	-	-	-	-	17,568
37	Regulatory Commission Expense	15,802	-	-	(1,472)	(4,851)	-	-	9,479
38	Miscellaneous General	5,550	-	-	-	-	-	-	5,550
39	**Administrative and General Expense**	62,843	-	-	(1,472)	(4,851)	-	-	56,520
40	Interest Expense - Customer Deposits	367	-	-	-	-	-	-	367
41	Depreciation and Amortization Expense	49,645	-	-	-	-	-	-	49,645
42	Tax Expense - Property	19,639	-	-	-	-	-	-	19,639
43	Tax Expense - Income Taxes	(30,460)	-	-	-	-	7,445	-	(23,015)
44		39,191	-	-	-	-	7,445	-	46,636
45	**Total Operating Expenses**	$ 696,345	$ -	$ (325,260)	$ (1,472)	$ (4,851)	$ 7,445	$ -	372,207
46	**Operating Margin Before Interest on L.T.- Debt**	$ (46,968)	$ 2,574	$ 118	$ 475	$ 4,851	$ (7,445)	$ -	(46,394)
47	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***	$ 31,112	$ -	$ -	$ -	$ -	$ -	$ (8,019)	23,093
48	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (78,080)	$ 2,574	$ 118	$ 475	$ 4,851	$ (7,445)	$ 8,019	$ (69,487)
49	***NON-OPERATING MARGINS***	$ 110	$ -	$ -	$ -	$ -	$ -	$ -	$ 110
50	***NET MARGINS (LOSS)***	$ (77,970)	$ 2,574	$ 118	$ 475	$ 4,851	$ (7,445)	$ 8,019	$ (69,377)

Duncan Rural Services Corporation
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Test Year Ended December 31, 2004

Schedule DTZ-8

OPERATING INCOME ADJUSTMENT NO. 1 - REVENUE ANNUALIZATION

Line	Classification Residential (250 cfh & Below)		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total	
1	Year end number of customers		747	747	747	747	747	747	747	747	747	747	747	747		
2	Less: Month end number of customers		740	747	746	740	740	740	729	735	734	730	740	747		
3	Number of Additional Customers	L1 - L2	7	0	1	7	7	7	18	12	13	17	7	0	96	Total Additional Billings
4	Total actual therms sold		77,497	83,124	50,043	34,476	32,183	51,718	45,921	30,785	31,811	25,644	42,952	67,982	574,136	Total Actual Therms Sold
5	Average therms per customer	L4 / L2	104.73	111.28	67.08	46.59	43.49	69.89	62.99	41.88	43.34	35.13	58.04	91.01		
6	Monthly customer charge		$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00		
7	Commodity charge[1]		$ 0.80	$ 0.80	$ 0.80	$ 0.51405	$ 0.51405	$ 0.51405	$ 0.51405	$ 0.51405	$ 0.51405	$ 0.51405	$ 0.80	$ 0.80		
8	Less: Base cost of gas		$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 0.36		
9	Margin (i.e. Non-gas) Rate	L 7 - L 8	$ 0.44	$ 0.44	$ 0.44	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.15	$ 0.44	$ 0.44		
10	**Calculation of Additional Revenue Due to Annualization**															
11	Avg bill based on Margin (Non-gas) Rate	L6 + (L5 x L9) / L2	$ 61.08	$ 63.96	$ 44.52	$ 22.18	$ 21.70	$ 25.77	$ 24.70	$ 21.45	$ 21.68	$ 20.41	$ 40.54	$ 55.04	$ 35.25	Average Bill
12	Multiplied by: Additional Customers (from Line 3)		7	-	1	7	7	7	18	12	13	17	7	-		
13	Additional Monthly Margin (Non-gas) Revenue L3 x L9		$ 427.56	$ -	$ 44.52	$ 155.24	$ 151.90	$ 180.37	$ 444.67	$ 257.43	$ 281.79	$ 347.00	$ 283.77	$ -	$ 2,574	**Additional Revenue**
14	**Calculation of Additional Therms Due to Annualization**															
15	Average therms per customer (from Line 5)		104.73	111.28	67.08	46.59	43.49	69.89	62.99	41.88	43.34	35.13	58.04	91.01		
16	Multiplied by: Customer Variance (from Line 3)		7	-	1	7	7	7	18	12	13	17	7	-		
17	Additional therms sold based on annualization L3 x L5		733.08	-	67.08	326.12	304.43	489.22	1,133.85	502.61	563.41	597.19	406.30	-	5,123	**Additional Therms**

18 [1] Winter Commodity Charge (November through March) = $ 0.80 per therm
19 Summer Commodity Charge (April through October) = $0.51405 per therm

Duncan Rural Services Corporation
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Test Year Ended December 31, 2004

Schedule DTZ-9

OPERATING INCOME ADJUSTMENT NO. 2
BASE COST OF GAS and FUEL ADJUSTOR
REVENUE AND EXPENSE

LINE NO.	DESCRIPTION		[A] Base Cost of Gas Revenue
1	**Revenues**		
2	Test Year Sales in therms (From Cooperative's revised 2004 RUS Form 7)		574,136
3	Base Cost of Gas (Col A, per Dec 64869)	$	0.360000
4	**Revenue from the Base Cost of Gas**	$	206,689
5	Plus: Fuel Adjustor Revenue (Cooperative Income Statement Adjustment A)	$	118,453
6	**Staff Adjustment to Remove Total Gas Cost from Revenue**	**$**	**325,142**
7	**Expenses**		
8	Staff Adjustment to Remove Purchased Gas Expense	**$**	**325,260**

References:
Column [A]: Testimony, DTZ

Duncan Rural Services Corporation
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Schedule DTZ-10

OPERATING INCOME ADJUSTMENT NO. 3 - ACC GROSS REVENUE ASSESSMENT

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Revenue - ACC Assessment	$ 997	$ (997)	$ -
2	Expense - ACC Assessment	$ 1,472	$ (1,472)	$ -

References:
Column A: Data request response DTZ 2-8
Column B: Testimony, DTZ
Column C: Column [A] + Column [B]

Duncan Rural Services Corporation
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Schedule DTZ-11

OPERATING INCOME ADJUSTMENT NO. 4 - RATE CASE EXPENSE

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENT**	**STAFF AS ADJUSTED**
1	Rate Case Expense	15,802	**(4,851)**	10,951

Calculation of Staff Recommended Rate Case Exp.		
Company proposed rate case expense	$	32,852
Normalization period (in years)		3
Normalized Annual Expense	$	10,951

References:
Column A: Cooperative Schedule C-2
Column B: Testimony, DTZ
Column C: Column [A] + Column [B]; DTZ 1-25

Duncan Rural Services Corporation
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Schedule DTZ-12

OPERATING INCOME ADJUSTMENT NO. 5 - INCOME TAX EXPENSE

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Income Tax Expense	$ (30,460)	**$ 7,445**	$ (23,015)

References:
Column A: Cooperative Schedules C-1 and C-2
Column B: Testimony, DTZ
Column C: Column [A] + Column [B]

Duncan Rural Services Corporation
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Schedule DTZ-13

OPERATING INCOME ADJUSTMENT NO. 6 - INTEREST EXPENSE ON LONG-TERM DEBT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Interest Expense on Existing Long-Term Debt	$ 14,973	$ (886)	$ 14,087
2	Interest Expense on Proposed Long-Term Debt	$ 16,139	$ (7,133)	$ 9,006
3	Total Interest Expense on Long-term Debt	$ 31,112	$ **(8,019)**	$ 23,093

Calculation of Interest Expense on Existing L.T. Debt

Line		31-Dec-04 Ending Balance	Variable Interest Rate	Interest Expense
8	Note 1	$ 60,412	2.725%	$ 1,646
9	Note 2	$ 115,962	2.725%	$ 3,160
10	Note 3	$ 340,584	2.725%	$ 9,281
11		$ 516,958		$ **14,087**

	Loan Amount	Variable Interest Rate	Interest Expense
Proposed Debt	$ 330,484	2.725%	$ **9,006**

References:
Column A: Cooperative Schedules C-1 and C-2
Column B: Testimony, DTZ
Column C: Column [A] + Column [B]

Duncan Rural Services Corporation
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Schedule DTZ-14

Sample Cooperatives Capital Structures

	Cooperative Utilities	Debt as a percentage of total capital[1]	Equity as a percentage of total capital[1]
1	Garkane Power Association, Inc.	50%	50%
2	Navopache Electric Cooperative, Inc.	75%	25%
3	Graham County Utilities	93%	7%
4	Alaska Electric & Energy Cooperative	76%	24%
5	Cherryland Electric Cooperative	49%	51%
6	Presque Isle Electric & Gas Cooperative	62%	38%
7	Great Lakes Energy Cooperative	60%	40%
8	Midwest Energy Cooperative	63%	37%
9	Thumb Electric Cooperative	67%	33%
10	Western Farmers Electric Cooperative	90%	10%
11	Bayfield Electric Cooperative	66%	34%
	Average	68.2%	31.8%
	Duncan Rural Services Corporation[2]	142.07%	-42.07%

[1] Information based on annual reports for the year ended 2004
[2] Based on the Company's rate filing

EXHIBIT
S-4
Admitted
12-15-05

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THER APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	))))	DOCKET NO. G-02528A-05-0314

SURREBUTTAL

TESTIMONY

OF

DANIEL ZIVAN

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 5, 2005

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
DUNCAN RURAL SERVICES CORPORATION
DOCKET NO. G-02528A-05-0314

The Surrebuttal testimony of Staff witness Daniel Zivan addresses the following issues:

<u>Long-term debt</u> – Staff's recommendation included in its direct testimony remains unchanged.

<u>Interest expense</u> – Staff's recommendation included in its direct testimony remains unchanged.

<u>Revenue annualization</u> – After reviewing the information provided in Duncan Rural Services Corporation ("Duncan") rebuttal testimony, Staff retracts its annualization adjustment included in its direct testimony. Staff's revised position decreases test year revenue by $2,574 and precipitates the need for an equal boost to the revenue increase.

<u>Line of credit</u> – Staff recommends approval of a $70,000 line of credit for Duncan to borrow from Duncan Valley Electric Cooperative for the exclusive purpose of financing increases to its under-collected Purchased Gas Adjustor ("PGA") bank balance.

<u>Revenue requirement</u> – Staff's recommendation included in its direct testimony remains unchanged.

<u>Arizona Corporation Commission Assessment Charge ("ACC Assessment") bill add-on</u> – Staff's recommendation included in its direct testimony remains unchanged.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Daniel Zivan. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Did you previously file direct testimony in this case?

A. Yes.

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. The purpose of my surrebuttal testimony in this proceeding is to present Staff's response to the rebuttal testimony of Duncan Rural Services Corporation ("Duncan" or the "Cooperative") witnesses Mr. Jack Shilling and Mr. John V. Wallace regarding long-term debt financing, interest expense, revenue annualization, a line of credit, revenue requirement and a bill add-on.

Q. What other Staff witnesses are involved in the presentation of Staff's responses to rebuttal testimonies?

A. Staff witness Steve Irvine is presenting Staff responses to the Cooperative's rebuttal testimonies regarding purchased gas adjustor ("PGA") $0.10 bandwidth, combining Summer and Winter rates, uniform commodity rates across customer classes, and the effect on rates from Staff's revocation of its $2,574 revenue annualization adjustment.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is organized in seven sections. Section I is this introduction. Section II discusses long-term debt. Section III discusses interest expense. Section IV discusses the Arizona Corporation Commission Assessment Charge ("ACC Assessment"). Section V discusses Staff's annualization adjustment. Section VI discusses Staff's recommendation for a line of credit. Section VII discusses the revenue requirement for Duncan.

II. LONG-TERM DEBT FINANCING

Q. Did Duncan change its financing request in its rebuttal testimony?

A. Yes. Duncan initially requested authorization to incur $268,988 of debt. Duncan's rebuttal increased the requested debt authorization to $600,000 to cover $502,000 of current advances from Duncan Valley Electric Cooperative, Inc. ("DVEC") and provide $98,000 for future advances from DVEC (Shilling Rebuttal at Page 6).

Q. Does Staff have concerns with Duncan's proposed loan amount of $600,000?

A. Yes. Duncan's capital structure at the end of the test year consisted of 142 percent debt and negative 42 percent patronage capital. Issuing any additional long-term debt would further exacerbate Duncan's excessively leveraged capital structure and make achieving Staff's recommended equity goals even more difficult. Additionally, issuing $600,000 of long-term debt would cause past operating expenses to be converted to long-term debt; therefore, putting the burden of paying past operating expenses on future customers.

Q. What amount of long-term debt is Staff recommending?

A. Staff recommends long-term debt financing in the amount of $330,484. This represents the amount that Duncan spent on plant improvements and the amount that Staff recommended in its direct testimony. In addition, as discussed later, Staff also recommends authorization for a $70,000 line of credit to finance the under-collected purchased gas adjustor ("PGA") balance to the extent that the under-collection increases from the balance at the time of implementation of new rates as ordered in this rate case.

Q. What support does Duncan provide to rebut Staff's position that authorizing debt to cover obligations resulting from previously incurred operating expenses would not result in cost shifting?

A. Duncan provided the following response.

> DRSC has experienced a decline in its customer base. DRSC's customer base has been the same customers who have taken service from DRSC for years. Consequently, its existing customers were present when these advances were incurred and are still present today (Shilling Rebuttal at Page 6).

Q. Would a declining customer base preclude the cost shifting?

A. No. A declining customer base shifts costs from customers that discontinue service to those that retain service since the Cooperative can no longer recover the costs incurred to provide service to customers that leave the system that have effectively been deferred for recovery to a later period.

Q. Does the Cooperative's rebuttal testimony correctly state Staff's position regarding Duncan's obligations to DVEC that are not authorized for conversion to long-term debt?

A. No. The Cooperative states:

> . . . Staff has not recommended that all of DRSC's cash advances be converted to LTD but has only recommended that $330,484 be converted and the remaining amounts of advances of $171,516 be repaid when these funds are available (Schilling Rebuttal at Page 4).

This statement is not accurate as Staff did not make a recommendation in its direct testimony regarding how the remaining advances should be treated.

Q. How does Staff view the remaining advances?

A. The remaining cash advances are not debt because they were not authorized by the Commission. However, the cash advances did occur, therefore, Staff views them as equity infusions from DVEC.

Q. Is the historical cash-advance relationship that has developed between DVEC and Duncan appropriate?

A. No. Duncan has continually borrowed money from DVEC effectively delaying applying for a rate increase. This behavior is an inappropriate way for Duncan to address its stressed financial situation and only serves to prolong and exacerbate its condition. As stated in Staff's direct testimony, the implication for DVEC from this relationship is less immediate cash available for its own operations and potential harm to its ratepayers in the event the advances are not repaid. Delays in repayment could affect the timing and amount of DVEC rate adjustments. Duncan should request rate relief when dictated by cash flow needs rather than relying on DVEC to pay operating expenses and fund plant improvements.

III. INTEREST EXPENSE

Q. What does Duncan recommend for interest expense?

A. In its rebuttal testimony Duncan recommends interest expense in the amount of $39,187 which includes $14,087 of interest expense on current loans and $25,100 of interest expense at 5 percent related to the $502,000 existing obligation to DVEC that is a portion of the requested $600,000 loan [$14,087 + ($502,000 x .05)] = $39,187.

Q. Does Staff agree with Duncan's use of 5 percent to determine the annual interest expense amount?

A. No. Duncan did not explain why it used an interest rate of 5 percent to calculate its interest expense. The applicable interest rate on long-term debt is equal to the Arizona Electric Power Cooperative Inc.'s ("AEPCO") interest rate charged on "270 Day Fixed Rate Notes", which is currently[1] 2.725 percent. There is no evidence that the rate has changed.

Q. Does Staff agree with the Cooperative's proposed interest expense?

A. No. First, Staff recommends interest expense based on existing debt and Staff's recommend $330,484 additional debt authorization. The Cooperative used the existing debt and $502,000 of requested debt to calculate interest expense. Second, Staff used an interest rate of 2.725 percent to determine the level of interest expense of $23,093 which represents $14,087 for existing long-term debt and $9,006 for the recommended $330,484 long-term debt. The Cooperative used $14,087 for the existing debt and applied a 5 percent rate to its $502,000 amount.

IV. ACC ASSESSMENT BILL ADD-ON

Q. Does Duncan agree with Staff's recommended Operating Income Adjustment No. 3 that removes the ACC Assessment from revenue and expenses?

A. Yes. Duncan agrees to the removal of the ACC Assessment from revenues and expenses (Wallace Rebuttal at Page 6). However, the Cooperative objects to recovering the ACC Assessment through a bill add-on. Staff has interpreted the Cooperative's objection as meaning it does not want to show the ACC Assessment as a separate line item on customer bills but would combine the Assessment with other charges.

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[1] September 2, 2005

Q. Is combining the ACC Assessment with other charges on the customer bill acceptable to Staff?

A. No. Placing the ACC Assessment on a separate line would require incurring programming costs with the Cooperative's current billing system. The Cooperative is in the process of updating its billing system to one that more readily provides a separate line for the ACC Assessment. The Cooperative is concerned with the cost of programming the current billing system when it is in the process of converting to a new one. The billing system update may take a year to complete. Staff is sympathetic to the Cooperative's circumstances and supports allowing Duncan to postpone presenting the ACC Assessment on a separate line until its billing system is updated.

V. REVENUE ANNUALIZATION

Q. Did Duncan present any support in its rebuttal testimony for its claim that Staff's Operating Income Adjustment No. 1 – Revenue Annualization is unnecessary because Duncan has not experienced measurable growth?

A. Yes. The Company's RUS Form 7 Report, Part R (Wallace, Rebuttal Attachment), shows that 2005 customer counts are less than the test year level. Therefore, Staff retracts its $2,574 adjustment to annualize test year revenue.

VI. LINE OF CREDIT

Q Does Staff recognize a potential cash flow need for Duncan in addition to rates?

A. Yes. Due to the magnitude and seasonality of the cost of gas for natural gas distribution utilities there is a significant seasonal lead or lag between recovery and payment of gas costs. For utilities such as Duncan with adjustor mechanisms, this lead or lag is reflected in a PGA bank balance. It is not unusual for a PGA bank balance to exceed the on-going cash flow generated from authorized returns. Accordingly, natural gas distributions utilities need a method to finance under-collected PGA bank balances. Accordingly, Duncan may require additional financing for under-collected gas costs.

Q. Does Staff have a recommendation that would assist the Cooperative with cash flow needs related to under-collected PGA bank balances?

A. Yes. Staff recommends authorization of a $70,000 revolving line of credit for Duncan to borrow funds from DVEC with an interest rate equal to the AEPCO's rate of interest charged on "270 Day Fixed Rate Notes", which is currently 2.725 percent.

Q. How should the line of credit be used?

A. The line of credit should be approved with the condition that it be used exclusively to address Duncan's under-collected PGA bank balance. Duncan would have use of the line of credit for amounts greater than the balance of the under-collected PGA bank balance at the time that rates from this rate proceeding are implemented. For example, if Duncan's under-collected bank balance at the implementation of the approved rates in this rate case is $30,000 and then after three months the under-collected PGA bank balance increased to $45,000, then Duncan would be able to borrow $15,000 against the line of credit. If the under-collected bank balance subsequently decreased to $35,000, then Duncan would be required to repay $10,000 of the line of credit balance to DVEC so that the borrowed balance each month is maintained at, or below, the amount that the under-collected balance exceeds $30,000. In this example, at no point would Duncan be able to borrow from the line of credit when the under-collected balance drops below $30,000, the balance at the date new rates become effective.

VII. REVENUE REQUIREMENT

Q. What is Duncan's proposed revenue increase?

A. Duncan requested a revenue increase of $147,406 in its initial application. The Cooperative's rebuttal testimony boosted the requested revenue increase to $167,705 (Wallace Rebuttal, Page 3). Duncan requested the additional increase to provide a 2.00 times interest earned ratio ("TIER") based on the assumption that the Commission authorizes $502,000 of additional long-term debt at 5 percent. Additionally, Duncan has requested a 5 percent rate increase effective January 1, 2006, which is 17 days after the scheduled December 15, 2005 hearing and another 5 percent increase to become effective January 1, 2007.

Duncan asserts that its revised revenue requirement is needed to comply with Staff's recommendations to increase equity to 30 percent of total capital and to discontinue use of unauthorized cash advances from DVEC (Schilling Rebuttal at Page 2).

Q. Are these reasons adequate justification for Duncan's boosted revenue requests?

A. No. First, as previously discussed, Staff is recommending authorization for a $70,000 line of credit from DVEC to finance increases in the Cooperative's PGA bank balance. Second, Staff's recommend revenue provides sufficient cash flow to achieve Staff's recommendation for the Cooperative to grow its equity by 5 percent yearly.

Q. What net margin must the Cooperative experience to grow equity by 5 percent?

A. The Cooperative's filing shows total capital of $363,884 at the end of the test year. If total capital remains at $363,884 at the end of 2005, the Cooperative will need a net margin of $18,194 ($363,000 x .05) to achieve Staff's recommended equity growth of five percent. Staff's recommended revenue results in a net margin of $42,682 providing an excess of

$24,488. In other words, the Cooperative can experience a combination of revenue declines or expense increases and still achieve 5 percent growth in equity.

Q. How will the Cooperative's estimated average $80,000 per year capital expenditures over the next five year affect its ability to achieve 5 percent growth in equity?

A. Assuming a 3.6 depreciation rate and a 3.00 percent interest expense, each $1,000 of incremental borrowing for capital expenditures will erode $116 of the $24,488 excess in the initial year and $66 each year thereafter. Table 1 below shows the net margin required in each of the first three years to support only the Cooperative's estimated $80,000 per year capital improvements and grow equity by 5 percent each year assuming all funds are borrowed and the Cooperative's equity balance remains negative.

Table 1

Year	Interest	Depreciation	Capital (5%)	Total
One	$2,400	$2,880	$4,000	$9,280
Two	$4,800	$5,760	$4,000	$14,560
Three	$7,200	$8,640	$4,000	$19,840

Combining the net margin requirement for year three (worst case scenario) of $19,840 with the $18,194 requirement based on the test year end results in a total annual net margin requirement of $38,034, which is less than the $42,682 net margin provided by Staff's recommended revenue.

SURREBUTTAL SUMMARY

Q. Please summarize Staff's surrebuttal testimony.

A. Staff recommends the following:

Long-term debt – Staff recommends that long-term debt financing in the amount of $330,484 be approved.

Interest expense – Staff recommends interest expense in the amount of $23,093.

Revenue annualization – Staff retracts the $2,574 annualization adjustment.

Line of credit – Staff recommends approval of a $70,000 line of credit for Duncan to borrow from Duncan Valley Electric Cooperative for the exclusive purpose of financing increases to its under-collected Purchased Gas Adjustor ("PGA") bank balance.

Revenue requirement – Staff recommends an increase in revenue of $149,981.

ACC Assessment bill add-on – Staff recommends that Duncan be ordered to have a separate bill add-on line for the ACC Assessment, however, Staff supports allowing the Cooperative to postpone presenting the ACC Assessment on a separate line until its billing system is updated.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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Surrebuttal Schedule DTZ-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST [1]
1	Adjusted Operating Income (Loss)	$	(46,968)	$	(47,976)
2	Depreciation and Amortization	$	49,645	$	49,645
3	Long-term Debt Interest Expense	$	31,112	$	23,093
4	Income Tax Expense		N/A	$	12,331
5	Principal Repayment	$	45,303	$	54,661
6	Recommended Increase in Operating Margin	$	108,814	$	113,641
7	Gross Revenue Conversion Factor		1.3514		1.3198
8a	**Recommended Increase in Operating Revenue**	$	147,406	**$**	**149,981**
8b	**Percent Increase (Line 8a / Line 9) - Per Staff**		N/A		**23.10%**
8c	Percent Increase (Line 8a / Line 9) - Per Coop		22.70%		N/A
9	Adjusted Test Year Operating Revenue	$	649,377	$	323,238
10	**Recommended Annual Operating Revenue**	$	796,783	**$**	**473,219**
11a	**Recommended Operating Margin**	$	61,846	**$**	**65,665**
11b	Recommended Net Margin	$	30,845	$	42,682
12a	**Recommended Operating TIER (L11a+L4)/L3 - Per Staff**		N/A		**3.38**
12b	Recommended Net TIER Per Coop		2.00		N/A
13a	**Recommended DSC (L11a+L2+L4)/(L3+L5) - Per Staff**		N/A		**1.64**
13b	Recommended DSC Per Coop		1.38		N/A
14	**Adjusted Rate Base**	$	772,408	**$**	**758,057**
15	Rate of Return (L10 / L14)		8.01%		8.66%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules DTZ-2, DTZ-8

[1] Staff recommendation reflects Duncan Rural Service Corporations initial revenue increase of $147,406. In rebuttal testimony the company has requested an increase of $167,705.

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Surrebuttal Schedule DTZ-2

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A) [1]	(B)	(C)	(D)
	Calculation of Gross Revenue Conversion Factor:				
1	Billings	1.000000			
2	Uncollectible Factor	0.000000			
3	Revenues	1.000000			
4	Less: Combined Federal and State Tax Rate (Line 12)	0.242297			
5	Subtotal (L3 - L4)	0.7577			
6	**Revenue Conversion Factor (L1 / L5)**	**1.31978**			
	Calculation of Effective Tax Rate:				
7	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
8	Arizona State Income Tax Rate	6.9680%			
9	Federal Taxable Income (L7 - L8)	93.0320%			
10	Applicable Federal Income Tax Rate (Line 34)	18.5545%			
11	Effective Federal Income Tax Rate (L9 x L10)	17.2617%			
12	Combined Federal and State Income Tax Rate (L8 +L11)	24.2297%			
13	Required Operating Income (Schedule DTZ-1, Line 5)	$ 65,665			
14	AdjustedTest Year Operating Income (Loss) (Schedule DTZ-10, Line 16)	$ (47,976)			
15	Required Increase in Operating Income (L13 - L14)		$ 113,641		
16	Income Taxes on Recommended Revenue (Col. (D), L33)	$ 12,331			
17	Income Taxes on Test Year Revenue (Col. (B), L33)	$ (24,008)			
18	Required Increase in Revenue to Provide for Income Taxes (L16 -L17)		$ 36,340		
19	Total Required Increase in Revenue (L15 + L18)		$ 149,980		
	Calculation of Income Tax:	Test Year		Staff Recommended	
20	Revenue (Schedule DTZ-9, Columns C and E)	$ 323,238	$ -	$ 473,218	
21	Less: Operating Expenses Excluding Income Taxes	$ 395,222		$ 395,222	
22	Less: Synchronized Interest (L37)	$ 20,657		$ 20,657	
23	Arizona Taxable Income (L20 - L21 - L22)	$ (92,641)		$ 57,339	
24	Arizona State Income Tax Rate	6.968%		6.968%	
25	Arizona Income Tax (L23 x L24)		$ (6,455)		$ 3,995
26	Federal Taxable Income (L23 - L25)	$ (86,185)		$ 53,344	
27	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ (7,500)		$ 7,500	
28	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ (6,250)		$ 836	
29	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ (3,803)		$ -	
30	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -		$ -	
31	Federal Tax on Fifth Income Bracket ($335,001 - $10,000,000) @ 34%	$ -		$ -	
32	Total Federal Income Tax		$ (17,553)		$ 8,336
33	Combined Federal and State Income Tax (L25 + L32)		$ (24,008)		$ 12,331
34	Applicable Federal Income Tax Rate [Col. (D), L32 - Col. (B), L32] / [Col. (C), L26 - Col. (A), L26]				18.5545%
	Calculation of Interest Synchronization:				
35	Rate Base (Schedule DTZ-3, Col. (C), Line 13	$ 758,057			
36	Weighted Average Cost of Debt	2.73%			
37	Synchronized Interest (L35 x L37)	$ 20,657			

[1] Staff recommendation reflects Duncan Rural Service Corporations initial revenue increase of $147,406. In rebuttal testimony the company has requested an increase of $167,705.

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Surrebuttal Schedule DTZ-3

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED [1]
1	***REVENUES:***					
2	Sales Revenue of Gas - Base Cost of Gas	$ 206,689	$ (206,689)	$ -	$ -	$ -
3	Sales Revenue of Gas - Fuel Adjustor	$ 118,453	$ (118,453)	$ -	$ -	$ -
4	Sales Revenue of Gas - Non Base Cost of Gas	$ 319,025	$ (997)	$ 318,028	$ 149,980	$ 468,008
5	Other Operating Revenue	$ 5,210	$ -	$ 5,210	$ -	$ 5,210
6	**Total Revenues**	$ 649,377	$ (326,139)	$ 323,238	$ 149,980	$ 473,218
7	***EXPENSES:***					
8	Gas Purchases	$ 325,260	$ (325,260)	$ -	$ -	$ -
9	***Distribution Expense - Operations***					
10	Supervision	$ 950	$ -	$ 950	$ -	$ 950
11	Mains & Services	$ 110,026	$ -	$ 110,026	$ -	$ 110,026
12	Measuring & Regulation Stations	$ 13,753	$ -	$ 13,753	$ -	$ 13,753
13	Meters & House Regulators	$ 20,214	$ -	$ 20,214	$ -	$ 20,214
14	Other Expenses	$ 3,116	$ -	$ 3,116	$ -	$ 3,116
15	Rents	$ 6,039	$ -	$ 6,039	$ -	$ 6,039
16	**Total Distribution Expense-Operations**	$ 154,098	$ -	$ 154,098	$ -	$ 154,098
17	***Distribution Expense - Maintenance***					
18	Maintenance-Supervision	$ -	$ -	$ -	$ -	$ -
19	Maintenance-Mains & Services	$ 46,098	$ -	$ 46,098	$ -	$ 46,098
20	Maintenance-Measuring & Regulation Stations	$ -	$ -	$ -	$ -	$ -
21	Maintenance-Services	$ -	$ -	$ -	$ -	$ -
22	Maintenance-Meters & House Regulators	$ 8,726	$ -	$ 8,726	$ -	$ 8,726
23	Maintenance-Other Equipment	$ -	$ -	$ -	$ -	$ -
24	**Total Distribution Expense-Maintenance**	$ 54,824	$ -	$ 54,824	$ -	$ 54,824
25	***Consumer Accounts Expense***					
26	Meter Reading Expense	$ 25,048	$ -	$ 25,048	$ -	$ 25,048
27	Consumer Expense	$ 30,523	$ -	$ 30,523	$ -	$ 30,523
28	Reserve for Uncollectible Accounts	$ 1,500	$ -	$ 1,500	$ -	$ 1,500
29	Information & Instruction ads	$ 3,058	$ -	$ 3,058	$ -	$ 3,058
30	**Total Consumer Accounts Expense**	$ 60,129	$ -	$ 60,129	$ -	$ 60,129
31	***Administrative and General Expense***					
32	Salaries	$ 8,491	$ -	$ 8,491	$ -	$ 8,491
33	Office Supplies and Expenses	$ 3,606	$ -	$ 3,606	$ -	$ 3,606
34	Outside Services Employed	$ 11,826	$ -	$ 11,826	$ -	$ 11,826
35	Rate Case	$ -	$ -	$ -	$ -	$ -
36	Property Insurance	$ -	$ -	$ -	$ -	$ -
37	Injuries and Damage Ins.	$ 17,568	$ -	$ 17,568	$ -	$ 17,568
38	Regulatory Commission Expense	$ 15,802	$ (6,323)	$ 9,479	$ -	$ 9,479
39	Miscellaneous General	$ 5,550	$ -	$ 5,550	$ -	$ 5,550
40	**Total Administrative and General Expense**	$ 62,843	$ (6,323)	$ 56,520	$ -	$ 56,520
41	Interest Expense - Customer Deposits	$ 367	$ -	$ 367	$ -	$ 367
42	Depreciation and Amortization Expense	$ 49,645	$ -	$ 49,645	$ -	$ 49,645
43	Tax Expense - Property	$ 19,639	$ -	$ 19,639	$ -	$ 19,639
44	Tax Expense - Income Taxes	$ (30,460)	$ 6,452	$ (24,008)	$ 36,339	$ 12,331
45	**Total Operating Expenses**	$ 696,345	$ (325,131)	$ 371,214	$ 36,339	$ 407,553
46	**Operating Margin Before Interest on L.T.- Debt**	$ (46,968)	$ (1,008)	$ (47,976)	$ 113,641	$ 65,665
47	**INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS**	$ 31,112	$ (8,019)	$ 23,093	$ -	$ 23,093
48	**MARGINS (LOSS) AFTER INTEREST EXPENSE**	$ (78,080)	$ 7,012	$ (71,068)	$ 113,641	$ 42,572
49	**NON-OPERATING MARGINS**	$ 110	$ -	$ 110	$ -	$ 110
50	**NET MARGINS (LOSS)**	$ (77,970)	$ 7,012	$ (70,958)	$ 113,641	$ 42,682

References:
Column (A): Cooperative Schedule C-1, Pages 1 and 2
Column (B): Schedule DTZ-8
Column (C): Column (A) + Column (B)
Column (D): Schedules DTZ-1
Column (E): Column (C) + Column (D)

[1] Staff recommendation reflects Duncan Rural Service Corporations initial revenue increase of $147,406. In rebuttal testimony the company has requested an increase of $167,705.

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SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Revenue Annualization Ref: Sch DTZ-9	[C] ADJ #2 Base Cost of Gas and Fuel Adjustor Ref: Sch DTZ-10	[D] ADJ #3 ACC Assessment Charge Ref: Sch DTZ-11	[E] ADJ #4 Rate Case Expense Ref: Sch DTZ-12	[F] ADJ #5 Income Tax Expense Ref: Sch DTZ-13	[G] ADJ #6 Interest Expense on Long Term Debt Ref: Sch DTZ-14	[H] STAFF ADJUSTED
	REVENUES:								
1	Sales Revenue of Gas - Base Cost of Gas	$ 206,689	$ -	$ (206,689)	$ -	$ -	$ -	$ -	$ -
2	Sales Revenue of Gas - Fuel Adjustor	118,453	-	(118,453)	-	-	-	-	-
3	Sales Revenue of Gas - Margin (Non-gas)	319,025	-	-	(997)	-	-	-	318,028
4	Other Operating Revenue	5,210	-	-	-	-	-	-	5,210
5	**Total Revenues**	$ 649,377	$ -	$ (325,142)	$ (997)	$ -	$ -	$ -	$ 323,238
6	*OPERATING EXPENSES:*								
7	Gas Purchases	$ 325,260	$ -	$ (325,260)	$ -	$ -	$ -	$ -	$ -
8	**Distribution Expense - Operations**								
9	Supervision	950	-	-	-	-	-	-	950
10	Mains & Services	110,026	-	-	-	-	-	-	110,026
11	Measuring & Regulation Stations	13,753	-	-	-	-	-	-	13,753
12	Meters & House Regulators	20,214	-	-	-	-	-	-	20,214
13	Other Expenses	3,116	-	-	-	-	-	-	3,116
14	Rents	6,039	-	-	-	-	-	-	6,039
15	**Distribution Expense - Operations**	154,098	-	-	-	-	-	-	154,098
16	**Distribution Expense - Maintenance**								-
17	Supervision	-	-	-	-	-	-	-	-
18	Mains & Services	46,098	-	-	-	-	-	-	46,098
19	Measuring & Regulation Stations	-	-	-	-	-	-	-	-
20	Services	-	-	-	-	-	-	-	-
21	Meters & House Regulators	8,726	-	-	-	-	-	-	8,726
22	Other Equipment	-	-	-	-	-	-	-	-
23	**Distribution Expense - Maintenance**	54,824	-	-	-	-	-	-	54,824
24	**Consumer Accounts Expense**								-
25	Meter Reading Expense	25,048	-	-	-	-	-	-	25,048
26	Consumer Expense	30,523	-	-	-	-	-	-	30,523
27	Reserve for Uncollectible Accounts	1,500	-	-	-	-	-	-	1,500
28	Information & Instruction ads	3,058	-	-	-	-	-	-	3,058
29	**Consumer Accounts Expense**	60,129	-	-	-	-	-	-	60,129
30	**Administrative and General Expense**								-
31	Salaries	8,491	-	-	-	-	-	-	8,491
32	Office Supplies and Expenses	3,606	-	-	-	-	-	-	3,606
33	Outside Services Employed	11,826	-	-	-	-	-	-	11,826
34	Rate Case	-	-	-	-	-	-	-	-
35	Property Insurance	-	-	-	-	-	-	-	-
36	Injuries and Damage Ins.	17,568	-	-	-	-	-	-	17,568
37	Regulatory Commission Expense	15,802	-	-	(1,472)	(4,851)	-	-	9,479
38	Miscellaneous General	5,550	-	-	-	-	-	-	5,550
39	**Administrative and General Expense**	62,843	-	-	(1,472)	(4,851)	-	-	56,520
40	Interest Expense - Customer Deposits	367	-	-	-	-	-	-	367
41	Depreciation and Amortization Expense	49,645	-	-	-	-	-	-	49,645
42	Tax Expense - Property	19,639	-	-	-	-	-	-	19,639
43	Tax Expense - Income Taxes	(30,460)	-	-	-	-	6,452	-	(24,008)
44		39,191	-	-	-	-	6,452	-	45,643
45	**Total Operating Expenses**	$ 696,345	$ -	$ (325,260)	$ (1,472)	$ (4,851)	$ 6,452	$ -	371,214
46	**Operating Margin Before Interest on L.T.- Debt**	$ (46,968)	$ -	$ 118	$ 475	$ 4,851	$ (6,452)	$ -	(47,976)
47	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***	$ 31,112	$ -	$ -	$ -	$ -	$ -	$ (8,019)	23,093
48	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (78,080)	$ -	$ 118	$ 475	$ 4,851	$ (6,452)	$ 8,019	$ (71,068)
49	***NON-OPERATING MARGINS***	$ 110	$ -	$ -	$ -	$ -	$ -	$ -	$ 110
50	***NET MARGINS (LOSS)***	$ (77,970)	$ -	$ 118	$ 475	$ 4,851	$ (6,452)	$ 8,019	$ (70,958)

EXHIBIT
S-5
12-15-05 Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF)
DUNCAN RURAL SERVICES CORPORATION)
FOR A RATE INCREASE)
)

DOCKET NO. G-02528A-05-0314

DIRECT

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 8, 2005

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EXECUTIVE SUMMARY
DUNCAN RURAL SERVICES CORPORATION
DOCKET NO. G-02528A-05-0314

Duncan Rural Services Corporation ("Duncan") is a non-profit corporation that supplies gas service to approximately 750 customers in Greenlee County, Arizona. Duncan's current rates were approved by the Commission in Decision No. 64869 (June 5, 2002).

On April 29, 2005, Duncan submitted an application seeking adjustment to its rates. The application seeks to increase revenue from each customer class. Staff recommends a rate design that balances the goals of equal sharing of a rate increase with equal sharing of system costs. In addition to changes in rates, Staff makes other recommendations that change the rate components. Staff recommends consolidation of the Summer and Winter Commodity Charges. Staff also recommends setting the base cost of gas at $0.00. In addition to these changes, Staff makes further recommendations related to these matters.

Staff's recommended rate design would have the effect of raising the average winter bill in the 250 cfh & Below class from $92.28 to $103.44. The average summer bill in this class would rise from $29.42 to $41.72.

Staff's recommendations are as follows:

1. Staff recommends resetting the base cost of gas to zero in the first complete billing period following a decision in this matter, but not sooner than 30 days.

2. Staff recommends that Duncan create and distribute specific customer education materials to explain the resetting of the base cost of gas to zero.

3. Staff recommends that information materials describing the change to the base cost of gas be submitted to the Director of the Utilities Division for review at least two weeks prior to release.

4. Staff recommends that when implementing the zero base cost of gas Duncan calculate the adjustor rate based on the previous 12 months' average total cost of gas.

5. Staff recommends that when implementing the zero base cost of gas the existing $0.10 band should be referenced against the previous 12 months' total cost of gas rather than the previous twelve months' adjustor rate.

6. Staff recommends that Duncan's PGA balance threshold level remain at $35,000.

7. Staff recommends that Duncan continue to submit adjustor reports on a monthly basis and that that the reports be filed within 2 months of the month that the report covers.

8. Staff recommends that a Duncan Officer certify, under oath, through an affidavit attached to each adjustor report that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

9. Staff recommends consolidation of the Summer and Winter Commodity Charges into a single commodity charge that applies all year.

10. Staff recommends approval of rates as proposed in Schedule SPI-1.

11. Staff recommends approval of service charges as proposed in Schedule SPI-1.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Steve Irvine. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I review monthly filings of purchased power adjustors and purchased gas adjustors. My duties also include processing of applications for rate increases, borderline agreements, tariff compliance filings, cost of capital analysis and various applications of other types.

Q. Please describe your educational background and professional experience.

A. In 1994, I graduated from Arizona State University, receiving a Bachelor of Science degree in Business Marketing. In 1997, I received a Masters degree in Public Administration from Arizona State University. I have been employed by the Commission since May of 2001. I have worked in the Utilities Division since September of 2002.

Q. What is the scope of your testimony in this case?

A. I will address Duncan Rural Services Corporation's ("Duncan", "Company", or "Cooperative") base cost of power, purchased gas adjustor ("PGA") and PGA balance, revenue allocation and rate design, and service charges. Staff witnesses Dan Zivan and Prem Bahl will provide testimony regarding other aspects of Duncan's rate application.

BASE COST OF GAS

Q. Briefly summarize how Staff determined the base cost of gas.

A. Typically the base cost of gas is determined by dividing the Cooperative's total purchased gas costs from the test year by the total therms sold in the test year. In this case, rather than using this typical method Staff recommends setting the base cost of gas to zero. By setting the base cost of gas to zero, in the future the entire cost of gas will be recovered through the adjustor mechanism.

Q. Why does Staff recommend setting the base cost of gas at zero and moving the entire cost of gas to the adjustor mechanism?

A. Staff recommends this method as it makes the cost of gas purchased by Duncan more transparent to the public. Aside from taxes and assessments, currently there are three rate components identified in Duncan's Rate Schedules I, II, and III. The first component is a fixed Monthly Service Charge. The second is a Commodity Charge which is a rate that is multiplied by each therm used. There are different Commodity Charges for winter and summer. The third component is the PGA. The PGA charge is also a rate that is multiplied by each therm used. The cost of the gas purchased for delivery to customers is recovered through a component of the Commodity Charge called the base cost of gas. It is a fixed rate that is charged per therm sold. Should the cost of gas differ from this fixed rate, the amount by which purchased gas costs differ from the base cost of gas is recovered, or alternatively returned, through the PGA. Other costs associated with the delivery of gas such as costs for metering, billing, customer service, personnel, facility costs, etc. are recovered through the Monthly Service Charge and the portion of the Commodity Charge which is not comprised of the base cost of gas. Under this framework, the cost of the gas purchased by Duncan is split between the Commodity Charge and the PGA. Currently, the monthly cost to customers for the gas purchased by

Duncan is determined by summing the base cost of gas and the costs reflected in the adjustor. Setting the base cost of gas to zero and moving gas costs entirely to the PGA consolidates purchased gas costs into a single rate component. This process will result in greater price transparency as gas costs can be readily observed in a single pricing component and will not require calculation to determine gas costs. This ability to easily understand the cost of purchased gas is increasingly more important as the cost of gas rises and becomes more volatile. This change would simplify the accounting necessary to be done in regard to the cost of gas in a rate proceeding and tracking of the PGA mechanism.

Q. Please discuss how Tables 1 and 2 shown below describe the current pricing method as it relates to Staff's proposed pricing method.

A. Table 1 includes the three pricing components mentioned above: Monthly Service Charge, Commodity Charge, and PGA. The right side of Table 1 also shows the kinds of costs included in each of the pricing components. Table 2 also shows the three pricing components and the costs proposed to be included for each of the price components, but with purchased gas costs consolidated into a single pricing component Gas costs would no longer mix with other costs in the Commodity Charge. Note that these tables exclude other charges such as taxes and surcharges.

Table 1

Current Pricing Method

Monthly Service Charge	Charges related to delivery and service
Winter and Summer Commodity Charge	Charges related to delivery and service combined with Purchased Gas charges (base cost of gas)
Purchased Gas Adjustor	Purchased Gas charges (adjustor mechanism)

Table 2

Proposed Pricing Method

Monthly Service Charge	Charges related to delivery and service
Winter and Summer Commodity Charge	Charges related to delivery and service
Purchased Gas Adjustor	Total Purchased Gas charges

Q. Are there any drawbacks to setting the base cost of gas at zero and effectively combining it with the monthly PGA rate to create a single gas cost component?

A. The only drawback Staff is aware of is that if such a change were to take place, some amount of customer confusion is likely in the short term, as is the case anytime there is a noticeable change to customer bills. However, a well-designed customer education effort to inform customers of this change will help to reduce customer confusion. Staff recommends that if the recommendation to set the base cost of gas at zero is accepted, that Duncan create and distribute specific customer education materials to explain this change.

Staff further recommends that such information materials be submitted to the Director of the Utilities Division for review at least two weeks prior to release. This will allow Staff to provide input into the informational materials. Staff also recommends resetting of the base cost of gas to zero in the first complete billing period following a decision in this matter, but not sooner than 30 days. This will allow a period of time for preparation and approval of informational materials.

Q. Will any adjustments need to be made to Duncan's current method of determining the adjustor rate to accommodate the setting of the base cost of gas to zero?

A. Yes. Currently, Duncan's monthly adjustor rate is calculated using the prior 12 months' average cost of gas. A given month's adjustor rate is determined by calculating the average of the past 12 months' gas costs and then reducing the amount by the base cost of gas. In order to allow the entire cost of gas to be reflected in the adjustor rate, Duncan will need to calculate the adjustor rate in a new manner. In the month in which Duncan resets the base cost of gas set to zero, the adjustor rate will need to be increased so that the adjustor will include costs that were previously recovered in the base cost of gas. In order to increase the adjustor rate, Duncan will need to calculate the adjustor rate based on the previous 12 months' average total cost of gas. Staff recommends that this measure be taken in order to properly shift gas cost from the base cost of gas to the adjustor mechanism.

Q. Please discuss the $0.10 band that currently sets limitations on the adjustor rate and describe any considerations that must be given to this band should the base cost be reset to zero.

A. A $0.10 band is in place that limits the extent to which a new adjustor rate can increase or decrease. The band limits any new adjustor rate to no more than $0.10 difference from any rate in the past 12 months. In the month in which the new adjustor rate is calculated based on the preceding 12 months' average total cost of gas, the new rate may well exceed $0.10 difference from any of the preceding twelve months' adjustor rates. In order for the new adjustor rate to allow the total cost of gas to be collected through the adjustor, the existing $0.10 band should be referenced against the previous 12 months' total cost of gas rather than the previous 12 months' adjustor rate. This will likely cause a marked increase in the adjustor rate, but the increase will be offset by a proportional decrease that occurs in the commodity charges from reducing the base cost of gas to zero. In the 13th month following a decision in this matter the $0.10 band should be referenced against the prior 12 months' PGA rates as the total cost of gas will be reflected in the prior 12 months' PGA rates.

Q. Has Staff recommended setting the base cost of gas at $0.00 previously?

A. Yes. Staff has made the same recommendation recently in a rate proceeding for Southwest Gas (G-01551A-04-0876).

Q. What is Staff's recommendation for Duncan's base cost of gas?

A. Staff recommends that the base cost of gas be set at $0.00 per therm.

PURCHASED GAS ADJUSTOR AND BALANCE

Q. Has use of the PGA mechanism maintained a reasonable PGA balance?

A. Yes, in the recent past it has. Decision No. 61225 in December 1998 set a PGA balance threshold of $35,000 for Duncan. The threshold requires that Duncan either seek a surcharge or surcredit upon reaching a $35,000 balance, or alternatively seek a waiver from a surcharge or surcredit. Since January of 2003, Duncan's PGA balance has been within the $35,000 threshold. Prior to that, Duncan's December 2002 balance was

$38,990 in overcollection. On September 30, 2005, Duncan filed an application for a surcharge. Duncan's ending August balance was $22,000 undercollected. While the August ending balance is within the threshold, Duncan cites in its application that it expects an undercollection of $192,000 by February of 2006 as a result of anticipated high winter costs and not having hedged gas for the winter. The surcharge application is being processed as a separate matter (Docket No. G-02528A-05-0687).

Q. Does Staff have any other recommendations regarding the PGA?

A. Yes. Decision No. 61225 ordered Duncan to file monthly PGA reports. Decision No. 61225 also ordered that monthly PGA reports be filed within 2 months of the month that the report covers. For example, the report for January 2006 should be filed by the last day of March 2006. Staff recommends that Duncan continue to submit adjustor reports on a monthly basis and that the reports be filed within 2 months after the month that the report covers.

Q. Does Staff have any other recommendations regarding the PGA?

A. Yes. Staff recommends that a Duncan Officer certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. Staff has made this recommendation in other rate cases. Increased accountability for PGA reports is appropriate as gas costs are rising. Staff notes that the reports are currently signed by Duncan's C.E.O., but the signature does not speak to the accuracy of the reports.

PGA THRESHOLD

Q. Has Staff given consideration to the possibility of making a change to the $35,000 threshold set in Decision No. 61225?

A. Yes.

Q. What objectives does Staff consider when evaluating the level of a bank balance threshold?

A. There are many factors to be considered in setting a threshold level. A threshold set too high may allow a company to maintain an excessive overcollection or allow an undercollection to develop to a level that later necessitates a high surcharge. A threshold set too low may require a company to file a burdensome number of surcharge or surcredit applications, or alternatively petition many waivers from such filings. In setting a threshold one must balance these and other factors.

Q. Can a company file an application for a surcredit or surcharge prior to reaching an established bank balance threshold?

A. Yes. Companies are not prohibited from filing for a surcharge or surcredit prior to reaching a balance threshold.

Q. What methods or tools might one use to evaluate the appropriateness of a bank balance threshold level?

A. When considering the severity of a given bank balance, or appropriateness of a given threshold level, Staff has relied on a formula which frames a bank balance level or threshold, in a meaningful context. Consider Company X whose threshold, or alternatively current balance level, is $67,000. The number $67,000 is meaningless to the observer until it is placed in context of the size of the utility and controlled for other factors such as the ratio of residential customers to other customer classes. A balance of $67,000 may be small to a company such as Arizona Public Service ("APS") but large to a small cooperative. Similarly, a threshold level of $67,000 may be small to APS but large to a small cooperative. Additionally, a $67,000 bank balance or balance threshold may be large for a small cooperative whose therms are sold predominantly to residential customers, but appropriate for a cooperative whose therms are sold predominately to an industrial customer. The formula Staff has employed when considering thresholds and bank balance levels first multiplies a given bank balance level, or balance threshold level by the ratio of residential therm sales to total therm sales. This yields the portion of the balance that is attributable to the residential class. This number is then divided by the average number of residential customers yielding the ratio referred to as balance per residential customer. While portions of an existing PGA bank balance are not formally ascribed to any given customer class or customer, the balance per residential customer ratio frames a given bank balance level or balance threshold in a ratio which is intuitive to the observer. Should Company X's bank balance referenced previously as $67,000 be $2.00 per residential customer, one can reason that a $67,000 bank balance does not call for remediation through a surcharge. Furthermore, one could also reason that a threshold set at the $67,000 level may be too low. The balance per residential customer ratio also allows direct comparisons to be made between small and large companies and controls for factors such as varying customer mix.

Q. Given that Duncan's current bank balance threshold level is $35,000, what is the balance per residential customer at that level?

A. Staff calculates that at $35,000 Duncan's balance per residential customer is $31.92.

Q. How does this compare to other utilities who have established thresholds?

A. Duncan's threshold balance per residential customer is high compared to other gas utilities. Duncan's threshold per residential customer being higher than others may be a result of other utilities' customer base having grown since setting of their thresholds and Duncan's customer base having reduced somewhat in the same period of time.

Q. What threshold level does Staff recommend for Duncan?

A. Given that Duncan's customer base has remained relatively stable, Staff recommends that Duncan's PGA balance threshold level remain at $35,000.

REVENUE ALLOCATION AND RATE DESIGN

Q. Before describing Staff's proposal for Revenue Allocation and Rate Design, please discuss how Duncan's customer classes differ from other Arizona utilities.

A. Typically, the rate classes of other utilities describe the kinds of users in the rate classes. Examples of more typical rate classes are Residential, Commercial, Irrigation, and Industrial. Duncan is unusual in that each rate class is determined by the potential volume per hour of the gas service delivered. For instance, Rate Schedule 1 – 250 cfh & Below consists of customers of meter sizes of 250 cubic feet per hour and below. Customers in this rate class could be either residential or commercial customers so long as their meter size is of 250 cfh or less. For this reason, general descriptions of the customers in each class are included in Table 3 below.

Table 3

Class	**Description***	**Approximate No. of customers****
Rate Schedule 1 – 250 cfh & Below	Residential and Commercial	691 Residential 47 Commercial
Rate Schedule 2 – Above 250 cfh to 425 cfh	Irrigation and Commercial	18 Irrigation 1 Commercial
Rate Schedule 3 – Above 425 cfh to 1,000 cfh	Commercial	2 Commercial

*Descriptions of users in each category are not formal, but general descriptions of the customers.

**These figures are an approximation provided by the Company.

Q. What are Staff's underlying objectives in its recommended revenue allocation and rate design?

A. Many factors are considered and balanced when performing revenue allocation. Equalization of contribution to the system rate of return is generally an objective in revenue allocation and rate design. Staff also gave consideration to other factors such as rate shock, gradualism in change, customer class price sensitivity, historic prices, and pricing simplicity. In light of the large increases needed and the rising cost of gas, Staff gave greater consideration to equal sharing of needed price increases among customer classes than to each class's contribution to system rate of return. Had Staff's revenue allocation emphasized equalization of rate of return for each class over equal sharing of rate increase, larger changes from present to new rates would have occurred for those rate classes (Rate Schedule 1 and 3) that currently contribute less than system rate of return.

Q. How did Staff calculate the rates of return that would be contributed by each class given Staff's proposed revenue allocation?

A. To calculate rates of return contributed by each class given Staff's proposed revenue allocation, Staff used the formulas from Worksheets G1 and G2 of Staff's cost of service study. Worksheets G1 and G2 of the cost of service study calculate, among other things, rates of return on revenue and a Return Index for each rate class. To calculate rates of return given Staff's proposed revenue allocation, Staff's proposed revenue increases for each class were entered in the Operating Revenues line of Schedule G2 in Staff's cost of service study. Staff's Schedule G2, which includes Staff's proposed revenue allocation, is shown in Exhibit SPI-3.

Q. Please explain the Return Index mentioned previously.

A. The Return Index that appears in Worksheets G1 and G2 of Staff's cost of service study is a ratio that indicates whether the rate of return on revenue contributed by a given class is above, equal to, or below the system rate of return on revenue. The ratio is determined by dividing the revenue contributed by a given class by the revenue needed for that class to have a rate of return equal to that contributed by each of the other classes. A Return Index above 1.00 indicates that a class contributes more than the system rate of return. Alternatively, a Return Index below 1.00 indicates that a class contributes less than the system rate of return.

Q. Please describe Duncan's proposed revenue allocation.

A. The company has proposed equal increases in the commodity based component of rates. Currently, each of the three rate classes has a Winter Commodity Rate of $0.80 per therm. Duncan proposes that this rate increase to $1.25450 for each customer class. Each class has a Summer Commodity Rate of $0.51405 per therm. Duncan proposes that this rate increase to $0.80580 for each customer class. Duncan has also proposed equally proportional increases to the Monthly Service Charge of each class. In total, Duncan's proposed rate design is aimed at equal sharing of the revenue increase. While equal sharing of revenues appears to be Duncan's prime consideration in rate design and revenue allocation, based on Duncan's cost of service study, Duncan's rate design also has the effect of making each class's rate of return more equal to the system rate of return.

Q. Does Staff's revenue allocation differ from Duncan's?

A. Yes. Some differences exist that result from systematic differences in rate design and the cost of service studies. First, Staff's cost of service study differs from that of Duncan resulting in differing return indices. Differences in the cost of service studies are described in the testimony of Staff witness Prem Bahl. Second, Staff is proposing that the base cost of gas be set to zero and that all future gas costs flow through the adjustor mechanism. This has the effect of changing the revenue requirements shown in the cost of service study as revenues meant to recover costs for the base cost of gas are no longer needed in the revenue requirement. For this reason, Duncan has proposed a higher revenue requirement than Staff.

Q. Please describe Staff's proposed revenue allocation.

A. Like Duncan's, Staff's revenue allocation pursues equal sharing of the costs associated with an increased revenue requirement; however, Staff does not propose exactly equal increases for each rate class. As discussed previously, these increases appear in the form of revenue reductions for each class as Staff has proposed that gas costs formerly included in each class's revenue requirements be collected through the adjustor mechanism. Staff recommends a revenue reduction for the 250 cfh & Below class of 22.94 percent, a revenue reduction for the Above 250 cfh to 425 cfh class of 41.05 percent, and a revenue reduction for the Above 425 cfh to 1,000 cfh class of 21.55 percent.

Q. Does Staff's proposal for revenue allocation give consideration to the return indices of each of the rate classes?

A. Staff did give consideration to the return indices of each of the rate classes when determining revenue allocation. While equalization of the return indices of each of the rate classes is generally desirable, Staff's primary goal was not equalizing the return indices. As discussed previously, Duncan has filed an application seeking a $0.60 per therm surcharge in anticipation of high winter gas costs. Gas costs have not only been rising recently but have also responded to the effects of hurricane Katrina. This problem is exacerbated by Duncan's lack of gas hedging for the winter. While the Commission has not yet issued a decision on Duncan's surcharge application, rate increases to address the new revenue requirement coupled with increasing gas costs will have a significant effect on customer bills. Regardless of the Commission's decision in the surcharge application, at least some portion of higher gas costs will pass on through Duncan's PGA rolling average. In light of these new costs, efforts to reallocate revenues among classes in order to equalize contribution to revenue requirement would have the effect of further significantly increasing bills of customers in rate classes that currently contribute less than the system average rate of return. For this reason, Staff's recommended revenue allocation considers equal sharing of new costs, before considering equalization of return indices.

Q. What is the effect of Staff's recommended revenue allocation on the return indices?

A. Staff's recommended revenue allocation would decrease the Return Index of the 250 cfh & Below class from 0.74 to 0.34. While this change moves the class further away from equal contribution to rate of return, the class will still collect revenue in excess of expenses. The Return Index of the Above 250 cfh to 425 cfh class increases from 4.12 to 9.03. The Return Index of the Above 425 cfh to 1,000 cfh class decreases from 0.61 to 0.15. One should note the current return indices referenced here are based on Staff's cost of service study rather than Duncan's. It should also be noted that while in each of these rate classes the return indices move further from equal rate of return, each rate class's rate of return remains positive. Each rate class continues to collect revenues in excess of expenses.

Q. Please describe Staff's proposed rate design generally.

A. A summary of Staff's proposed rate design is provided in Schedule SPI-1. Duncan's present rate design is based on a Monthly Service Charge and Summer and Winter Commodity Charges. Staff accepts the Cooperative's proposed Monthly Service Charges. Equivalent increases in the Monthly Service Charges were approved in Duncan Valley Electric Cooperative's first three rate classes in its most recent rate case. Duncan recommends that equal increases be made to the Summer and Winter Commodity Charges of each rate class. Staff agrees with the concept of equivalent increases to the commodity component of each rate class.

Q. Does Staff recommend any changes to the structure of Duncan's rate classes?

A. Yes. Staff recommends consolidation of the Summer and Winter Commodity Charges into a single commodity charge that applies all year. Costs recovered by the commodity charges, above the base cost of gas, do not change seasonally. There is no cost-based rationale for having different commodity charges for the summer and winter season.

Q. Please describe Staff's proposed rate design for the 250 cfh & Below class and its effect on the class.

A. Staff finds the Cooperative's proposed monthly customer charge of $20.00 to be reasonable. Staff recommends that the Commodity Charge be set at $0.52 per therm. Based on average monthly usage of 76 therms in winter, a customer in this class would pay $103.44, an increase of 12.09 percent, or $11.16. Based on average monthly usage of 20 therms in summer, a customer would pay $41.72, an increase of 41.77 percent, or $12.29. These bill calculations include the Monthly Minimum Charge, Commodity Charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. While an increase of 41.77 percent appears to be a large increase, this increase occurs in summer when average bills for this class are lower than winter bills. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-2.

Q. Please describe Staff's proposed rate design for the Above 250 cfh to 425 cfh class and its effect on the class.

A. Staff finds the Cooperative's proposed monthly customer charge of $30.00 to be reasonable. Staff recommends that the Commodity Charge be set at $0.42 per therm. Based on average monthly usage of 262 therms in winter, a customer in this class would pay $288.99, an increase of 0.47 percent, or $1.36. Based on average monthly usage of 997 therms in summer, a customer would pay $1,014.93, an increase of 36.12 percent, or $269.33. These bill calculations include the Monthly Minimum Charge, Commodity Charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. Staff would endeavor to reduce the increase to this class even further, but such efforts would further add to the large increases experiences by other classes. Proportionally, increases to this class are smaller than those of other classes as the class already contributes more than its share of rate of return. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-2.

Q. Please describe Staff's proposed rate design for the Above 425 cfh to 1,000 cfh class and its effect on the class.

A. Staff finds the Cooperative's proposed monthly customer charge of $40.00 to be reasonable. Staff recommends that the Commodity Charge be set at $0.74 per therm. Based on average monthly usage of 1,430 therms in winter, a customer in this class would pay $1,915.57, an increase of 29.80 percent, or $439.84. Based on average monthly usage of 128 therms in summer, a customer would pay $207.88, an increase of 69.28 percent, or $85.08. These bill calculations include the Monthly Minimum Charge, Commodity Charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. While a percentage increase of 69.28 is remarkably high, this increase occurs in summer when average bills are nearly one-tenth that of winter bills. One should also note that these summer bills are presently even smaller than either the average summer or winter bills in the Above 250 cfh to 425 cfh class. Furthermore, Staff's proposed rate design results in a decrease of the Return Index of this class and results in a significant increase in the Return Index of the Above 250 cfh to 425 cfh class. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-2.

SERVICE CHARGES

Q. What are Staff's recommendations regarding service charges?

A. Staff recommends that the services charges proposed by Duncan be approved. These service related charges are shown in Schedule SPI-1.

Q. Please discuss Duncan's proposal for service charges.

A. Duncan proposes that service charges remain the same with the exception of Interest Rate on Customer Deposits and Late/Deferred Payment. Duncan recommends that the interest rate on Customer Deposits be changed from 3 percent to a variable rate which is based on the Three Month Non-Financial Commercial Paper Rate ("NTMCP") as published by the Federal Reserve. While a variable interest rate is applied to deposits for some electric utilities in Arizona, all other natural gas utilities in Arizona currently have a flat interest rate of 6 percent and none currently use a variable rate. Staff recommends that Duncan's interest rate on deposits be increased from 3 percent to 6 percent in order to make it consistent with other Arizona gas utilities, but given Duncan's current financial condition the Commission could also consider maintaining the rate at its current level of 3 percent.

Q. What is Staff's recommendation regarding Late/Deferred Payment?

A. Duncan proposes that the rate for Late/Deferred Payment (per month) be changed from 0.0 percent to 1.5 percent. Staff recommends that this rate be approved. The fee would provide an incentive for timely payment and has been approved for other Arizona gas utilities.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a brief summary of Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff recommends resetting the base cost of gas to zero in the first complete billing period following a decision in this matter, but not sooner than 30 days.
2. Staff recommends that Duncan create and distribute specific customer education materials to explain the resetting of the base cost of gas to zero.

3. Staff recommends that informational materials describing the change to the base cost of gas be submitted to the Director of the Utilities Division for review at least two weeks prior to release.

4. Staff recommends that when implementing the zero base cost of gas, Duncan calculate the adjustor rate based on the previous 12 months' average total cost of gas and not reduce this number by the amount of the base cost of gas as it has done in the past.

5. Staff recommends that when implementing the zero base cost of gas the existing $0.10 band should be referenced against the previous 12 months' total cost of gas.

6. Staff recommends that Duncan's PGA balance threshold level remain at $35,000.

7. Staff recommends that Duncan continue to submit adjustor reports on a monthly basis and that the reports be filed within 2 months of the month that the report covers.

8. Staff recommends that a Duncan Officer certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

9. Staff recommends consolidation of the Summer and Winter Commodity Charges into a single commodity charge that applies all year.

10. Staff recommends approval of rates as shown on page 1 of Schedule SPI-1.

11. Staff recommends approval of service charges as shown on page 1 of Schedule SPI-1.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Rate Design
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

RATE DESIGN

		Company		Staff	
	Present rates	Proposed Rates	% change	Proposed Rates	% change
Monthly Minimum Charge					
<250	$15.00	$20.00	33%	$20.00	33.33%
250<425	$22.50	$30.00	33%	$30.00	33.33%
425<1000	$30.00	$40.00	33%	$40.00	33.33%
Energy (Commodity) Rate - Per Therm					
<250					
winter	$0.80000	$1.25405	57%	$0.52480	-34.40%
summer	$0.51405	$0.80580	57%	$0.52480	2.09%
250<425					
winter	$0.80000	$1.25405	57%	$0.42080	-47.40%
summer	$0.51405	$0.80580	57%	$0.42080	-18.14%
425<1000					
winter	$0.80000	$1.25405	57%	$0.74480	-6.90%
summer	$0.51405	$0.80580	57%	$0.74480	44.89%
Service Related Charges					
Establishment of Service - Regular Hours	$35.00	$35.00	0.00%	$35.00	0.00%
Establishment of Service - After Hours	$50.00	$50.00	0.00%	$50.00	0.00%
Reconnect/Re-establishment of Service - Regular Hour	$50.00	$50.00	0.00%	$50.00	0.00%
Reconnect/Re-establishment of Service - After Hour	$75.00	$75.00	0.00%	$75.00	0.00%
After Hours Service Call*	$50.00	$50.00	0.00%	$50.00	0.00%
Meter Re-read (No charge for Read error)	$30.00	$30.00	0.00%	$30.00	0.00%
Meter Test Fee	$50.00	$50.00	0.00%	$50.00	0.00%
Insufficient Funds Check	$20.00	$20.00	0.00%	$20.00	0.00%
Interest on Consumer Deposits	3.00%	Variable**		6.00%	
Late/Deferred Payment (Per Month)	0.00%	1.50%		1.50%	

*One hour minimum
**Based on Three Month Non-Financial
Federal Reserve Commercial Paper Rate

TYPICAL BILL ANALYSIS
BASED ON AVERAGE THERM CONSUMPTION

Company Proposed

		Avg Therms Used Per Bill	Present Rates*	Proposed Rates	Dollar Increase	Percent Increase
250 cfh & Below	Winter	76	$92.28	$115.86	$ 23.58	25.55%
250 cfh & Below	Summer	20	$29.42	$36.03	$ 6.61	22.45%
Above 250 cfh to 425 cfh	Winter	262	$287.63	$358.87	$ 71.24	24.77%
Above 250 cfh to 425 cfh	Summer	997	$745.60	$833.64	$ 88.04	11.81%
Above 425 cfh to 1,000 cfh	Winter	1,430	$1,475.73	$1,833.29	$ 357.56	24.23%
Above 425 cfh to 1,000 cfh	Summer	128	$122.81	$143.14	$ 20.34	16.56%

Staff Proposed

		Avg Therms Used Per Bill	Present Rates*	Proposed Rates*	Dollar Increase	Percent Increase
250 cfh & Below	Winter	76	$92.28	$103.44	$11.16	12.09%
250 cfh & Below	Summer	20	$29.42	$41.72	$12.29	41.77%
Above 250 cfh to 425 cfh	Winter	262	$287.63	$288.99	$1.36	0.47%
Above 250 cfh to 425 cfh	Summer	997	$745.60	$1,014.93	$269.33	36.12%
Above 425 cfh to 1,000 cfh	Winter	1,430	$1,475.73	$1,915.57	$439.84	29.80%
Above 425 cfh to 1,000 cfh	Summer	128	$122.81	$207.88	$85.08	69.28%

*Note that Staff has proposed a single annual rate. This column represents bills given average seasonal usage.

Typical Bill Analysis
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

BASED ON VARIOUS THERM CONSUMPTION LEVELS
250 cfh & Below

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change over winter	% Change over summer
0	$ 15.00	$ 20.00	33.33%	$ 15.00	$ 20.00	33.33%	$20.00	33.33%	33.33%
25	$ 40.28	$ 51.35	27.50%	$ 33.13	$ 40.15	21.19%	$47.29	17.42%	42.76%
50	$ 65.55	$ 82.70	26.17%	$ 51.25	$ 60.29	17.63%	$74.58	13.77%	45.51%
60	$ 75.66	$ 95.24	25.88%	$ 58.50	$ 68.35	16.83%	$85.50	13.00%	46.14%
70	$ 85.77	$ 107.78	25.67%	$ 65.75	$ 76.41	16.20%	$96.41	12.41%	46.62%
75	$ 90.83	$ 114.05	25.58%	$ 69.38	$ 80.44	15.94%	$101.87	12.16%	46.83%
80	$ 95.88	$ 120.32	25.49%	$ 73.00	$ 84.46	15.70%	$107.33	11.94%	47.01%
90	$ 105.99	$ 132.86	25.36%	$ 80.25	$ 92.52	15.29%	$118.24	11.56%	47.33%
100	$ 116.10	$ 145.40	25.24%	$ 87.51	$ 100.58	14.94%	$129.16	11.25%	47.60%
125	$ 141.38	$ 176.76	25.03%	$ 105.63	$ 120.73	14.29%	$156.45	10.66%	48.11%
150	$ 166.65	$ 208.11	24.88%	$ 123.76	$ 140.87	13.83%	$183.74	10.25%	48.47%
175	$ 191.93	$ 239.46	24.77%	$ 141.88	$ 161.02	13.48%	$211.03	9.95%	48.73%
200	$ 217.20	$ 270.81	24.68%	$ 160.01	$ 181.16	13.22%	$238.32	9.72%	48.94%
250	$ 267.75	$ 333.51	24.56%	$ 196.26	$ 221.45	12.83%	$292.90	9.39%	49.24%
300	$ 318.30	$ 396.21	24.48%	$ 232.52	$ 261.74	12.57%	$347.48	9.17%	49.44%
350	$ 368.85	$ 458.92	24.42%	$ 268.77	$ 302.03	12.38%	$402.05	9.00%	49.59%
400	$ 419.40	$ 521.62	24.37%	$ 305.02	$ 342.32	12.23%	$456.63	8.88%	49.71%
450	$ 469.95	$ 584.32	24.34%	$ 341.27	$ 382.61	12.11%	$511.21	8.78%	49.80%
500	$ 520.50	$ 647.02	24.31%	$ 377.53	$ 422.90	12.02%	$565.79	8.70%	49.87%
750	$ 773.25	$ 960.54	24.22%	$ 558.79	$ 624.35	11.73%	$838.69	8.46%	50.09%
1000	$ 1,026.00	$ 1,274.05	24.18%	$ 740.05	$ 825.80	11.59%	$1,111.58	8.34%	50.20%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	$0.5668
Fuel Adjustor Included in Company Proposed Rates	$0.0000

BASED ON VARIOUS THERM CONSUMPTION LEVELS
Above 250 cfh to 425 cfh

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change over winter	% Change over summer
0	$ 22.50	$ 30.00	33.33%	$ 22.50	$ 30.00	33.33%	$30.00	33.33%	33.33%
25	$ 47.78	$ 61.35	28.42%	$ 40.63	$ 50.15	23.43%	$54.69	14.47%	34.62%
50	$ 73.05	$ 92.70	26.90%	$ 58.75	$ 70.29	19.64%	$79.38	8.66%	35.11%
60	$ 83.16	$ 105.24	26.55%	$ 66.00	$ 78.35	18.70%	$89.26	7.33%	35.23%
70	$ 93.27	$ 117.78	26.28%	$ 73.25	$ 86.41	17.96%	$99.13	6.28%	35.33%
75	$ 98.33	$ 124.05	26.17%	$ 76.88	$ 90.44	17.63%	$104.07	5.84%	35.37%
80	$ 103.38	$ 130.32	26.06%	$ 80.50	$ 94.46	17.34%	$109.01	5.44%	35.41%
90	$ 113.49	$ 142.86	25.88%	$ 87.75	$ 102.52	16.83%	$118.88	4.75%	35.47%
100	$ 123.60	$ 155.40	25.73%	$ 95.01	$ 110.58	16.39%	$128.76	4.17%	35.53%
125	$ 148.88	$ 186.76	25.44%	$ 113.13	$ 130.73	15.55%	$153.45	3.07%	35.64%
150	$ 174.15	$ 218.11	25.24%	$ 131.26	$ 150.87	14.94%	$178.14	2.29%	35.72%
175	$ 199.43	$ 249.46	25.09%	$ 149.38	$ 171.02	14.48%	$202.83	1.71%	35.78%
200	$ 224.70	$ 280.81	24.97%	$ 167.51	$ 191.16	14.12%	$227.52	1.25%	35.82%
250	$ 275.25	$ 343.51	24.80%	$ 203.76	$ 231.45	13.59%	$276.90	0.60%	35.89%
300	$ 325.80	$ 406.21	24.68%	$ 240.02	$ 271.74	13.22%	$326.28	0.15%	35.94%
350	$ 376.35	$ 468.92	24.60%	$ 276.27	$ 312.03	12.95%	$375.65	-0.18%	35.97%
400	$ 426.90	$ 531.62	24.53%	$ 312.52	$ 352.32	12.74%	$425.03	-0.44%	36.00%
450	$ 477.45	$ 594.32	24.48%	$ 348.77	$ 392.61	12.57%	$474.41	-0.64%	36.02%
500	$ 528.00	$ 657.02	24.44%	$ 385.03	$ 432.90	12.43%	$523.79	-0.80%	36.04%
750	$ 780.75	$ 970.54	24.31%	$ 566.29	$ 634.35	12.02%	$770.69	-1.29%	36.09%
1000	$ 1,033.50	$ 1,284.05	24.24%	$ 747.55	$ 835.80	11.81%	$1,017.58	-1.54%	36.12%
1250	$ 1,286.25	$ 1,597.56	24.20%	$ 928.81	$ 1,037.26	11.68%	$1,264.48	-1.69%	36.14%
1500	$ 1,539.00	$ 1,911.07	24.18%	$ 1,110.08	$ 1,238.71	11.59%	$1,511.38	-1.79%	36.15%
1750	$ 1,791.75	$ 2,224.59	24.16%	$ 1,291.34	$ 1,440.16	11.52%	$1,758.27	-1.87%	36.16%
2000	$ 2,044.50	$ 2,538.10	24.14%	$ 1,472.60	$ 1,641.61	11.48%	$2,005.17	-1.92%	36.17%
2500	$ 2,550.00	$ 3,165.12	24.12%	$ 1,835.13	$ 2,044.51	11.41%	$2,498.96	-2.00%	36.17%
3000	$ 3,055.50	$ 3,792.15	24.11%	$ 2,197.65	$ 2,447.41	11.37%	$2,992.75	-2.05%	36.18%
4000	$ 4,066.50	$ 5,046.20	24.09%	$ 2,922.70	$ 3,253.22	11.31%	$3,980.34	-2.12%	36.19%
5000	$ 5,077.50	$ 6,300.24	24.08%	$ 3,647.75	$ 4,059.02	11.27%	$4,967.92	-2.16%	36.19%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	$0.5668
Fuel Adjustor Included in Company Proposed Rates	$0.0000

Typical Bill Analysis
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

BASED ON VARIOUS THERM CONSUMPTION LEVELS
Above 425 cfh to 1,000 cfh

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change over winter	% Change over summer
0	$ 30.00	$ 40.00	33.33%	$ 30.00	$ 40.00	33.33%	$40.00	33.33%	33.33%
10	$ 40.11	$ 52.54	30.99%	$ 37.25	$ 48.06	29.01%	$53.12	32.43%	42.59%
20	$ 50.22	$ 65.08	29.59%	$ 44.50	$ 56.12	26.10%	$66.23	31.88%	48.83%
50	$ 80.55	$ 102.70	27.50%	$ 66.25	$ 80.29	21.19%	$105.58	31.07%	59.36%
100	$ 131.10	$ 165.40	26.17%	$ 102.51	$ 120.58	17.63%	$171.16	30.56%	66.98%
150	$ 181.65	$ 228.11	25.58%	$ 138.76	$ 160.87	15.94%	$236.74	30.33%	70.61%
200	$ 232.20	$ 290.81	25.24%	$ 175.01	$ 201.16	14.94%	$302.32	30.20%	72.74%
250	$ 282.75	$ 353.51	25.03%	$ 211.26	$ 241.45	14.29%	$367.90	30.11%	74.14%
300	$ 333.30	$ 416.21	24.88%	$ 247.52	$ 281.74	13.83%	$433.48	30.06%	75.13%
350	$ 383.85	$ 478.92	24.77%	$ 283.77	$ 322.03	13.48%	$499.05	30.01%	75.87%
400	$ 434.40	$ 541.62	24.68%	$ 320.02	$ 362.32	13.22%	$564.63	29.98%	76.44%
450	$ 484.95	$ 604.32	24.62%	$ 356.27	$ 402.61	13.01%	$630.21	29.95%	76.89%
500	$ 535.50	$ 667.02	24.56%	$ 392.53	$ 442.90	12.83%	$695.79	29.93%	77.26%
750	$ 788.25	$ 980.54	24.39%	$ 573.79	$ 644.35	12.30%	$1,023.69	29.87%	78.41%
1000	$ 1,041.00	$ 1,294.05	24.31%	$ 755.05	$ 845.80	12.02%	$1,351.58	29.84%	79.01%
1250	$ 1,293.75	$ 1,607.56	24.26%	$ 936.31	$ 1,047.26	11.85%	$1,679.48	29.81%	79.37%
1500	$ 1,546.50	$ 1,921.07	24.22%	$ 1,117.58	$ 1,248.71	11.73%	$2,007.38	29.80%	79.62%
1750	$ 1,799.25	$ 2,234.59	24.20%	$ 1,298.84	$ 1,450.16	11.65%	$2,335.27	29.79%	79.80%
2000	$ 2,052.00	$ 2,548.10	24.18%	$ 1,480.10	$ 1,651.61	11.59%	$2,663.17	29.78%	79.93%
2500	$ 2,557.50	$ 3,175.12	24.15%	$ 1,842.63	$ 2,054.51	11.50%	$3,318.96	29.77%	80.12%
3000	$ 3,063.00	$ 3,802.15	24.13%	$ 2,205.15	$ 2,457.41	11.44%	$3,974.75	29.77%	80.25%
3500	$ 3,568.50	$ 4,429.17	24.12%	$ 2,567.68	$ 2,860.32	11.40%	$4,630.55	29.76%	80.34%
4000	$ 4,074.00	$ 5,056.20	24.11%	$ 2,930.20	$ 3,263.22	11.37%	$5,286.34	29.76%	80.41%
4500	$ 4,579.50	$ 5,683.22	24.10%	$ 3,292.73	$ 3,666.12	11.34%	$5,942.13	29.75%	80.46%
5000	$ 5,085.00	$ 6,310.24	24.10%	$ 3,655.25	$ 4,069.02	11.32%	$6,597.92	29.75%	80.51%
5500	$ 5,590.50	$ 6,937.27	24.09%	$ 4,017.78	$ 4,471.93	11.30%	$7,253.71	29.75%	80.54%
6000	$ 6,096.00	$ 7,564.29	24.09%	$ 4,380.30	$ 4,874.83	11.29%	$7,909.51	29.75%	80.57%

NOTE:
Fuel Adjustor Included in Present Rates $0.2110
Fuel Adjustor Included in Staff Proposed Rates $0.5668
Fuel Adjustor Included in Company Proposed Rates $0.0000

DUNCAN RURAL SERVICES CORPORATION
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2004

DESCRIPTION	TOTAL	250cfh & Below	>250 & < 425 cfh	>425 & < 1k cfh
Operating Revenues	**477,825**	**385,400**	**78,360**	**14,065**
Operating Expenses:				
Purchased Gas	-	-	-	-
Distribution Expense - Operations	154,097	134,924	12,508	6,665
Distribution Expense - Maintenance	54,824	48,107	4,413	2,304
Customer Account Expense	60,129	58,455	1,509	165
Administrative & General Expense	56,520	50,520	4,490	1,510
Depreciation	49,646	44,090	3,809	1,747
Property Taxes	19,639	17,021	1,656	962
Tax Expense - Other (Income, etc.)	12,305	10,999	978	328
Interest Expense -Other	367	357	9	1
Total Operation Expenses	**407,524**	**364,473**	**29,372**	**13,682**
Operating Income (Loss)	**70,301**	**20,927**	**48,988**	**383**
Rate Base	**758,058**	**672,374**	**58,472**	**27,212**
% Return - Proposed Rates	**9.27%**	**3.11%**	**83.78%**	**1.41%**
Return Index	**1.00**	**0.34**	**9.03**	**0.15**
Allocated Interest - Long-Term	**23,007**	**20,407**	**1,775**	**826**

EXHIBIT
S-6
12-15-05
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF DUNCAN RURAL SERVICES CORPORATION FOR A RATE INCREASE	DOCKET NO. G-02528A-05-0314

SURREBUTTAL

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 5, 2005

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
DUNCAN RURAL SERVICES CORPORATION
DOCKET NO. G-02528A-05-0314

The surrebuttal testimony of Staff witness Steve Irvine addresses the following issues:

PGA Adjustor Bandwidth – Duncan Rural Services Corporation ("Duncan") proposes applying the existing $0.10 PGA Adjustor bandwidth limit on a monthly basis, i.e., allowing $0.10 variances each month instead of over the course of 12 months. Staff does not support this recommendation. This could result in increased variability in the PGA rate at a time when customer's bills are rising due to other conditions such as a recently approved surcharge, this rate case, and rising gas costs. Staff recommends approval of a line of credit from Duncan Valley Electric Cooperative to be used exclusively to finance growth of the under-collected PGA balance.

Combination of Summer and Winter Rates – Duncan proposes a higher winter per therm rate than the summer per therm rate. Given that customers will experience higher rates associated with the factors mentioned previously, Staff does not find it prudent to recommend a rate design that has higher costs in winter. Duncan's design would create an unnecessary cost burden during the winter season when use peaks for many customers. Staff recommends consolidation of the summer and winter commodity charges into a single commodity charge that applies all year, as shown in Staff Exhibit SPI-4.

Uniform Commodity Rates – Duncan proposes uniform Summer and uniform Winter commodity rates for all three customer classes. Staff adopted Duncan's proposed monthly service charges and subsequently determined the commodity rates giving consideration to Staff's cost of service study. Given that Staff's cost of service study indicates a different cost of service for each rate class, Staff recommends distinct commodity rates for each of the three rate classes as contained in SPI-4.

Revenue Annualization Adjustment – Surrebuttal Testimony of Staff witness Dan Zivan retracts an annualization adjustment that had increased test year revenue by $2,574. However, Staff inadvertently used the unadjusted billing determinants to design the rates in its Direct Testimony. Since Staff's rate design already reflects the appropriate billing determinants, retraction of the revenue annualization adjustment has no effect on Staff's rate design (SPI-1 and SPI-4).

Adjusted Rate Design – Two implementation errors occurred when developing the rate design Staff recommended in its Direct Testimony (SPI-1). Staff now recommends the rate design as contained in SPI-4 to correct these errors. The commodity rate in the 250 cfh & Below class has changed from $0.53480 to $0.57280 per therm. The commodity rate in the 250 cfh to 425 cfh class has changed from $0.42080 to $0.28480. The commodity rate in the 425 cfh to 1000 cfh class has changed from $0.74480 to $0.74880.

In summary, Staff continues to advocate adoption of the same fundamental rate structure recommended in its Direct Testimony modified to correct implementation errors. Staff's recommended rate design is presented in Staff Exhibit SPI-4.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Steve Irvine. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Did you previously file Direct Testimony in this case?

A. Yes.

Q. What matters are addressed in your Surrebuttal Testimony?

A. This surrebuttal testimony addresses comments contained in the rebuttal testimonies of Duncan Rural Services Corporation ("Duncan") witnesses Mr. Jack Shilling and Mr. John V. Wallace regarding the Purchased Gas Adjustor's ("PGA") $0.10 bandwidth, combining Summer and Winter rates and uniform commodity rates across customer classes. This surrebuttal also addresses the effect on rates from Staff's revocation of its $2,574 revenue annualization adjustment and submits a new rate design (SPI-4) as a result of implementation errors present in Staff's original rate design (SPI-1).

PGA ADJUSTOR $0.10 BANDWIDTH

Q. How is Duncan's current PGA adjustor rate calculated?

A. Currently, Duncan's adjustor rate is determined each month by calculating the average of the past 12 months' gas cost and subtracting base cost of gas. Use of this method results in less change in customers' bills from one month to the next than what would occur should rates change each month based on the actual cost of gas. The adjustor rate that this formula yields is further subject to a constraint that reduces the variability in the cost of gas paid by customers. That constraint comes in the form of a $0.10 bandwidth that limits any new month's PGA rate to no more than a $0.10 per therm difference from any rate present in the previous 12 months.

Q. What is Duncan proposing regarding the $0.10 bandwidth on the PGA adjustor?

A. Duncan proposes to apply the $0.10 bandwidth limit on a monthly basis, i.e., allow $0.10 variances each month instead of over the course of 12 months (Shilling Rebuttal at Page 8). Duncan's proposal to allow the PGA rate to change by as much as $0.10 per therm each month has the potential to dramatically increase the variability in the PGA rate.

Q. Does Staff agree with Duncan's proposal to change the $0.10 bandwidth to allow a $0.10 per therm change from one month to the next?

A. No. Several factors exist currently that make such a change untimely: Decision No. 68297 (November 14, 2005) approved a $0.45 per therm surcharge, this rate case contemplates an increase in rates, and gas prices have been volatile and rising in the recent past. Changing the bandwidth implementation method at this time could result in increased burden to Duncan customers. Staff recognizes that a more restrictive bandwidth application can result in a larger under-collected PGA balance and increased financial burden for Duncan. Accordingly, Staff recommends approval of a line of credit from Duncan Valley Electric Cooperative to be ~~use~~ used exclusively to finance growth of the Duncan under-collected PGA balance. Specifically, Staff recommends a $70,000 credit line to finance the under-collected PGA balance to the extent that the under-collection increases from the balance at the time of implementation of new rates as ordered in this rate case. This recommendation for a revolving line of credit is discussed in detail in Surrebuttal Testimony of Staff witness Daniel Zivan.

UNIFORM SUMMER AND WINTER RATES

Q. What has Duncan proposed regarding the summer and winter commodity rates?

A. In both Direct and Surrebuttal Testimony, Mr. Wallace proposes a higher winter per therm rate than the summer per therm rate.

Q. What are Staff's comments regarding Mr. Wallace's proposal for distinct summer and winter rates?

A. As cited earlier, there are presently several conditions that lend to higher rates for Duncan customers: a recently approved $0.45 per therm surcharge, an increased revenue requirement contemplated in this rate case, and the rising cost of gas. Duncan's current summer commodity rate currently is $0.51 per therm and the winter commodity rate is $0.80 per therm. Given that customers will experience higher rates associated with the factors mentioned previously, Staff does not find it prudent to recommend a rate design that has higher costs in Winter. Duncan's rate design would create an unnecessary cost burden during the Winter season when use peaks for many customers. Staff continues to recommend consolidation of the summer and winter commodity rate into a single commodity rate that applies all year, as shown in Staff Exhibit SPI-1.

UNIFORM COMMODITY RATES

Q. What is Duncan's proposal for the commodity rates for the three customer classes?

A. Duncan proposes uniform summer and uniform winter commodity rates for all three customer classes (Wallace Rebuttal at Page 10). More specifically, Duncan proposes a $0.73 per therm winter commodity rate for all three rate classes and a $0.26 per therm the summer commodity rate for all three customer classes.

Q. What support does Duncan provide for its proposal for uniform commodity rates among the three customer classes?

A. Duncan offers the following statement (Wallace Rebuttal at Page 10).

> Besides the differences in the service line and meter that are recovered in the fixed monthly charge, the other distribution costs to serve the three customer classes are similar. Therefore, DRSC is recommending that the summer and winter rates be equal for all three classes.

Q. What does Staff's cost of service study reveal regarding whether Staff's or Duncan's rate design more closely matches the cost to serve the three customer classes?

A. Staff's cost of service study indicates that Staff's proposed rate design is closer to the actual cost of service than the rate design proposed by Duncan.

Q. What is Staff's recommendation for commodity rates?

A. Staff recommends the same monthly customer charges proposed by Duncan. Staff also recommends all but one of Duncan's proposed service charges. Given these components of the rate design, the commodity rates must be determined to provide the revenue requirement. Since Staff's cost of service study indicates that the three customer classes do not contribute equally to the system rate of return, Staff selected a distinct commodity rate for each of the three rate classes. Accordingly, Staff recommends the commodity rates presented in SPI-4.

STAFF'S REVENUE ANNUALIZATION ADJUSTMENT

Q. How does retraction of Staff's previous recommendation for a revenue annualization adjustment of $2,574 affect Staff's rate design?

A. The Surrebuttal Testimony of Staff witness Dan Zivan retracts an annualization adjustment that had increased test year revenue by $2,574. Properly reflecting the now retracted annualization adjustment would have required *increasing* billing determinants. Spreading the revenue requirement over a larger billing determinant base would have resulted in lower rates. However, Staff inadvertently used the unadjusted billing determinants to design the rates in its Direct Testimony. The unadjusted billing determinants should be used with Staff's revised position. Since Staff's rate design already reflects the appropriate billing determinants, retraction of the revenue annualization adjustment has no effect on Staff's rate design (SPI-1 and SPI-4).

ADJUSTED RATE DESIGN

Q. Does Staff continue to recommend the rate design contained in its Direct Testimony (SPI-1)?

A. No. Staff discovered two implementation errors in development of its rate design. One error double counted revenues from service related charges. The other error incorrectly derived relative customer class data from the cost of service study. Staff now recommends the rate design contained in SPI-4 to correct the errors.

Q. Do the changes in SPI-4 represent a significant change in the structure of Staff's rate design?

A. The structure of Staff's revised rate design is unchanged. However, the revenue spread among customer classes changed.

Q. Please provide a summary of changes from present rates to Staff's recommended rates.

A. The commodity rate in the 250 cubic feet per hour ("cfh") & Below class has changed from $0.53480 to $0.57280 per therm. The commodity rate in the 250 cfh to 425 cfh class has changed from $0.42080 to $0.28480. The commodity rate in the 425 cfh to 1000 cfh class has changed from \$0.74480 to \$0.74880. Schedules SPI-4 and SPI-5 reflect these adjustments. It should also be noted that SPI-5, Page 1 of 4, now includes typical monthly bills based on an average usage for a whole year in addition to bills based on seasonally averaged winter and summer usage. This line is marked 'Annual'.

Q. What are the effects of this change to rates in the 250 cfh & Below class?

A. The "Return Index" for this class decreases from its present level of 0.74 to 0.68. Based on average monthly usage of 44 therms, a customer would pay \$69.70, an increase of 24.93 percent, or \$13.91. This bill calculation includes the monthly minimum charge, commodity charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-5.

Q. What are the effects of this change to rates in the 250 cfh to 425 cfh class?

A. The "Return Index" increases from its present level of 4.12 to 5.10. Based on average monthly usage of 741 therms, a customer would pay \$660.62, an increase of 12.81 percent, or \$75.00. This bill calculation includes the monthly minimum charge, commodity charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-5.

Q. What are the effects of this change to rates in the in the 425 cfh to 1000 cfh class?

A. The "Return Index" decreases from its present level of 0.61 to 0.19. Based on average monthly usage of 701 therms, a customer would pay \$962.07, an increase of 33.98 percent, or \$243.97. This bill calculation includes the monthly minimum charge, commodity charge, and an estimated PGA rate. Taxes, assessments, surcharges, and surcredits are not included in the calculations. Effects of rate changes on customer bills over a range of use levels for each of the rate classes are shown in Schedule SPI-5.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a brief summary of Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff recommends approval of a $70,000 credit line to finance the under-collected PGA balance to the extent that the under-collection increases from the balance at the time of implementation of new rates as ordered in this rate case.

2. Staff recommends approval of rates shown on page 1 of Schedule SPI-1.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Rate Design
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

RATE DESIGN

		Company		Staff	
	Present rates	Proposed Rates	% change	Proposed Rates	% change
Monthly Minimum Charge					
<250	$15.00	$20.00	33.33%	$20.00	33.33%
250<425	$22.50	$30.00	33.33%	$30.00	33.33%
425<1000	$30.00	$40.00	33.33%	$40.00	33.33%
Energy (Commodity) Rate - Per Therm					
<250					
winter	$0.80000	$0.73000	-8.75%	$0.57280	-28.40%
summer	$0.51405	$0.26000	-49.42%	$0.57280	11.43%
250<425					
winter	$0.80000	$0.73000	-8.75%	$0.28480	-64.40%
summer	$0.51405	$0.26000	-49.42%	$0.28480	-44.60%
425<1000					
winter	$0.80000	$0.73000	-8.75%	$0.74880	-6.40%
summer	$0.51405	$0.26000	-49.42%	$0.74880	45.67%
Service Related Charges					
Establishment of Service - Regular Hour	$35.00	$35.00	0.00%	$35.00	0.00%
Establishment of Service - After Hour	$50.00	$50.00	0.00%	$50.00	0.00%
Reconect/Re-establishment of Service - Regular Hour	$50.00	$50.00	0.00%	$50.00	0.00%
Reconect/Re-establishment of Service - After Hour	$75.00	$75.00	0.00%	$75.00	0.00%
After Hours Service Call*	$50.00	$50.00	0.00%	$50.00	0.00%
Meter Re-read (No charge for Read error)	$30.00	$30.00	0.00%	$30.00	0.00%
Meter Test Fee	$50.00	$50.00	0.00%	$50.00	0.00%
Insufficient Funds Check	$20.00	$20.00	0.00%	$20.00	0.00%
Interest on Consumer Depoits	3.00%	**Variable		6.00%	
Late/Deferred Payment (Per Month)	0.00%	1.50%		1.50%	

*One hour minimum
**Based on Three Month Non-Financial
Federal Reserve Commercial Paper Rate

Typical Bill Analysis
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

TYPICAL BILL ANALYSIS
BASED ON AVERAGE THERM CONSUMPTION

Company Proposed

		Avg Therms Used Per Bill	Present Rates	Proposed Rates	Dollar Increase	Percent Increase
250 cfh & Below	Winter	76	$92.28	$119.13	$ 26.85	29.09%
250 cfh & Below	Summer	20	$29.42	$36.45	$ 7.02	23.87%
250 cfh & Below	Annual	44	$55.79	$71.13	$ 15.34	27.49%
Above 250 cfh to 425 cfh	Winter	262	$287.63	$370.08	$ 82.45	28.66%
Above 250 cfh to 425 cfh	Summer	997	$745.60	$854.56	$ 108.96	14.61%
Above 250 cfh to 425 cfh	Annual	741	$585.61	$685.31	$ 99.70	17.02%
Above 425 cfh to 1,000 cfh	Winter	1,430	$1,475.73	$1,894.40	$ 418.67	28.37%
Above 425 cfh to 1,000 cfh	Summer	128	$122.81	$145.83	$ 23.02	18.75%
Above 425 cfh to 1,000 cfh	Annual	701	$718.09	$915.20	$ 197.11	27.45%

Staff Proposed

		Avg Therms Used Per Bill	Present Rates	Proposed Rates*	Dollar Increase	Percent Increase
250 cfh & Below	Winter	76	$92.28	$107.11	$14.83	16.07%
250 cfh & Below	Summer	20	$29.42	$42.67	$13.25	45.02%
250 cfh & Below	Annual	44	$55.79	$69.70	$13.91	24.93%
Above 250 cfh to 425 cfh	Winter	262	$287.63	$253.33	-$34.31	-11.93%
Above 250 cfh to 425 cfh	Summer	997	$745.60	$879.30	$133.69	17.93%
Above 250 cfh to 425 cfh	Annual	741	$585.61	$660.62	$75.00	12.81%
Above 425 cfh to 1,000 cfh	Winter	1,430	$1,475.73	$1,921.29	$445.56	30.19%
Above 425 cfh to 1,000 cfh	Summer	128	$122.81	$208.39	$85.59	69.69%
Above 425 cfh to 1,000 cfh	Annual	701	$718.09	$962.07	$243.97	33.98%

*Note that Staff has proposed a single annual rate. This column represents bills given average seasonal usage.

BASED ON VARIOUS THERM CONSUMPTION LEVELS
250 cfh & Below

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change **over winter**	% Change **over summer**
0	$ 15.00	$ 20.00	33.33%	$ 15.00	$ 20.00	33.33%	$ 20.00	33.33%	33.33%
25	$ 40.28	$ 38.25	-5.03%	$ 33.13	$ 26.50	-20.00%	$ 48.49	20.40%	46.38%
50	$ 65.55	$ 56.50	-13.81%	$ 51.25	$ 33.00	-35.61%	$ 76.98	17.44%	50.20%
60	$ 75.66	$ 63.80	-15.68%	$ 58.50	$ 35.60	-39.15%	$ 88.38	16.81%	51.06%
70	$ 85.77	$ 71.10	-17.10%	$ 65.75	$ 38.20	-41.90%	$ 99.77	16.32%	51.73%
75	$ 90.83	$ 74.75	-17.70%	$ 69.38	$ 39.50	-43.07%	$ 105.47	16.12%	52.02%
80	$ 95.88	$ 78.40	-18.23%	$ 73.00	$ 40.80	-44.11%	$ 111.17	15.94%	52.27%
90	$ 105.99	$ 85.70	-19.14%	$ 80.25	$ 43.40	-45.92%	$ 122.56	15.64%	52.72%
100	$ 116.10	$ 93.00	-19.90%	$ 87.51	$ 46.00	-47.43%	$ 133.96	15.38%	53.09%
125	$ 141.38	$ 111.25	-21.31%	$ 105.63	$ 52.50	-50.30%	$ 162.45	14.91%	53.79%
150	$ 166.65	$ 129.50	-22.29%	$ 123.76	$ 59.00	-52.33%	$ 190.94	14.57%	54.28%
175	$ 191.93	$ 147.75	-23.02%	$ 141.88	$ 65.50	-53.84%	$ 219.43	14.33%	54.65%
200	$ 217.20	$ 166.00	-23.57%	$ 160.01	$ 72.00	-55.00%	$ 247.92	14.14%	54.94%
250	$ 267.75	$ 202.50	-24.37%	$ 196.26	$ 85.00	-56.69%	$ 304.90	13.87%	55.35%
300	$ 318.30	$ 239.00	-24.91%	$ 232.52	$ 98.00	-57.85%	$ 361.88	13.69%	55.64%
350	$ 368.85	$ 275.50	-25.31%	$ 268.77	$ 111.00	-58.70%	$ 418.85	13.56%	55.84%
400	$ 419.40	$ 312.00	-25.61%	$ 305.02	$ 124.00	-59.35%	$ 475.83	13.46%	56.00%
450	$ 469.95	$ 348.50	-25.84%	$ 341.27	$ 137.00	-59.86%	$ 532.81	13.38%	56.13%
500	$ 520.50	$ 385.00	-26.03%	$ 377.53	$ 150.00	-60.27%	$ 589.79	13.31%	56.23%
750	$ 773.25	$ 567.50	-26.61%	$ 558.79	$ 215.00	-61.52%	$ 874.69	13.12%	56.53%
1000	$ 1,026.00	$ 750.00	-26.90%	$ 740.05	$ 280.00	-62.16%	$ 1,159.58	13.02%	56.69%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	$0.5668
Fuel Adjustor Included in Company Proposed Rates	$0.5668

BASED ON VARIOUS THERM CONSUMPTION LEVELS
Above 250 cfh to 425 cfh

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change **over winter**	% Change **over summer**
0	$ 22.50	$ 30.00	33.33%	$ 22.50	$ 30.00	33.33%	$ 30.00	33.33%	33.33%
25	$ 47.78	$ 48.25	0.99%	$ 40.63	$ 36.50	-10.16%	$ 51.29	7.36%	26.25%
50	$ 73.05	$ 66.50	-8.97%	$ 58.75	$ 43.00	-26.81%	$ 72.58	-0.64%	23.53%
60	$ 83.16	$ 73.80	-11.26%	$ 66.00	$ 45.60	-30.91%	$ 81.10	-2.48%	22.87%
70	$ 93.27	$ 81.10	-13.05%	$ 73.25	$ 48.20	-34.20%	$ 89.61	-3.92%	22.33%
75	$ 98.33	$ 84.75	-13.81%	$ 76.88	$ 49.50	-35.61%	$ 93.87	-4.53%	22.10%
80	$ 103.38	$ 88.40	-14.49%	$ 80.50	$ 50.80	-36.90%	$ 98.13	-5.08%	21.89%
90	$ 113.49	$ 95.70	-15.68%	$ 87.75	$ 53.40	-39.15%	$ 106.64	-6.03%	21.52%
100	$ 123.60	$ 103.00	-16.67%	$ 95.01	$ 56.00	-41.06%	$ 115.16	-6.83%	21.21%
125	$ 148.88	$ 121.25	-18.56%	$ 113.13	$ 62.50	-44.75%	$ 136.45	-8.35%	20.61%
150	$ 174.15	$ 139.50	-19.90%	$ 131.26	$ 69.00	-47.43%	$ 157.74	-9.42%	20.17%
175	$ 199.43	$ 157.75	-20.90%	$ 149.38	$ 75.50	-49.46%	$ 179.03	-10.23%	19.84%
200	$ 224.70	$ 176.00	-21.67%	$ 167.51	$ 82.00	-51.05%	$ 200.32	-10.85%	19.59%
250	$ 275.25	$ 212.50	-22.80%	$ 203.76	$ 95.00	-53.38%	$ 242.90	-11.75%	19.21%
300	$ 325.80	$ 249.00	-23.57%	$ 240.02	$ 108.00	-55.00%	$ 285.48	-12.38%	18.94%
350	$ 376.35	$ 285.50	-24.14%	$ 276.27	$ 121.00	-56.20%	$ 328.05	-12.83%	18.75%
400	$ 426.90	$ 322.00	-24.57%	$ 312.52	$ 134.00	-57.12%	$ 370.63	-13.18%	18.60%
450	$ 477.45	$ 358.50	-24.91%	$ 348.77	$ 147.00	-57.85%	$ 413.21	-13.45%	18.48%
500	$ 528.00	$ 395.00	-25.19%	$ 385.03	$ 160.00	-58.44%	$ 455.79	-13.68%	18.38%
750	$ 780.75	$ 577.50	-26.03%	$ 566.29	$ 225.00	-60.27%	$ 668.69	-14.35%	18.08%
1000	$ 1,033.50	$ 760.00	-26.46%	$ 747.55	$ 290.00	-61.21%	$ 881.58	-14.70%	17.93%
1250	$ 1,286.25	$ 942.50	-26.72%	$ 928.81	$ 355.00	-61.78%	$ 1,094.48	-14.91%	17.84%
1500	$ 1,539.00	$ 1,125.00	-26.90%	$ 1,110.08	$ 420.00	-62.16%	$ 1,307.38	-15.05%	17.77%
1750	$ 1,791.75	$ 1,307.50	-27.03%	$ 1,291.34	$ 485.00	-62.44%	$ 1,520.27	-15.15%	17.73%
2000	$ 2,044.50	$ 1,490.00	-27.12%	$ 1,472.60	$ 550.00	-62.65%	$ 1,733.17	-15.23%	17.69%
2500	$ 2,550.00	$ 1,855.00	-27.25%	$ 1,835.13	$ 680.00	-62.95%	$ 2,158.96	-15.33%	17.65%
3000	$ 3,055.50	$ 2,220.00	-27.34%	$ 2,197.65	$ 810.00	-63.14%	$ 2,584.75	-15.41%	17.61%
4000	$ 4,066.50	$ 2,950.00	-27.46%	$ 2,922.70	$ 1,070.00	-63.39%	$ 3,436.34	-15.50%	17.57%
5000	$ 5,077.50	$ 3,680.00	-27.52%	$ 3,647.75	$ 1,330.00	-63.54%	$ 4,287.92	-15.55%	17.55%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	$0.5668
Fuel Adjustor Included in Company Proposed Rates	$0.5668

BASED ON VARIOUS THERM CONSUMPTION LEVELS
Above 425 cfh to 1,000 cfh

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change **over winter**	% Change **over summer**
0	$ 30.00	$ 40.00	$0.33	$ 30.00	$ 40.00	33.33%	$ 40.00	33.33%	33.33%
10	$ 40.11	$ 47.30	$0.18	$ 37.25	$ 42.60	14.36%	$ 53.16	32.53%	42.70%
20	$ 50.22	$ 54.60	$0.09	$ 44.50	$ 45.20	1.57%	$ 66.31	32.04%	49.01%
50	$ 80.55	$ 76.50	-$0.05	$ 66.25	$ 53.00	-20.00%	$ 105.78	31.32%	59.66%
100	$ 131.10	$ 113.00	-$0.14	$ 102.51	$ 66.00	-35.61%	$ 171.56	30.86%	67.37%
150	$ 181.65	$ 149.50	-$0.18	$ 138.76	$ 79.00	-43.07%	$ 237.34	30.66%	71.04%
200	$ 232.20	$ 186.00	-$0.20	$ 175.01	$ 92.00	-47.43%	$ 303.12	30.54%	73.20%
250	$ 282.75	$ 222.50	-$0.21	$ 211.26	$ 105.00	-50.30%	$ 368.90	30.47%	74.62%
300	$ 333.30	$ 259.00	-$0.22	$ 247.52	$ 118.00	-52.33%	$ 434.68	30.42%	75.62%
350	$ 383.85	$ 295.50	-$0.23	$ 283.77	$ 131.00	-53.84%	$ 500.45	30.38%	76.36%
400	$ 434.40	$ 332.00	-$0.24	$ 320.02	$ 144.00	-55.00%	$ 566.23	30.35%	76.94%
450	$ 484.95	$ 368.50	-$0.24	$ 356.27	$ 157.00	-55.93%	$ 632.01	30.33%	77.40%
500	$ 535.50	$ 405.00	-$0.24	$ 392.53	$ 170.00	-56.69%	$ 697.79	30.31%	77.77%
750	$ 788.25	$ 587.50	-$0.25	$ 573.79	$ 235.00	-59.04%	$ 1,026.69	30.25%	78.93%
1000	$ 1,041.00	$ 770.00	-$0.26	$ 755.05	$ 300.00	-60.27%	$ 1,355.58	30.22%	79.54%
1250	$ 1,293.75	$ 952.50	-$0.26	$ 936.31	$ 365.00	-61.02%	$ 1,684.48	30.20%	79.91%
1500	$ 1,546.50	$ 1,135.00	-$0.27	$ 1,117.58	$ 430.00	-61.52%	$ 2,013.38	30.19%	80.16%
1750	$ 1,799.25	$ 1,317.50	-$0.27	$ 1,298.84	$ 495.00	-61.89%	$ 2,342.27	30.18%	80.34%
2000	$ 2,052.00	$ 1,500.00	-$0.27	$ 1,480.10	$ 560.00	-62.16%	$ 2,671.17	30.17%	80.47%
2500	$ 2,557.50	$ 1,865.00	-$0.27	$ 1,842.63	$ 690.00	-62.55%	$ 3,328.96	30.16%	80.66%
3000	$ 3,063.00	$ 2,230.00	-$0.27	$ 2,205.15	$ 820.00	-62.81%	$ 3,986.75	30.16%	80.79%
3500	$ 3,568.50	$ 2,595.00	-$0.27	$ 2,567.68	$ 950.00	-63.00%	$ 4,644.55	30.15%	80.89%
4000	$ 4,074.00	$ 2,960.00	-$0.27	$ 2,930.20	$ 1,080.00	-63.14%	$ 5,302.34	30.15%	80.95%
4500	$ 4,579.50	$ 3,325.00	-$0.27	$ 3,292.73	$ 1,210.00	-63.25%	$ 5,960.13	30.15%	81.01%
5000	$ 5,085.00	$ 3,690.00	-$0.27	$ 3,655.25	$ 1,340.00	-63.34%	$ 6,617.92	30.15%	81.05%
5500	$ 5,590.50	$ 4,055.00	-$0.27	$ 4,017.78	$ 1,470.00	-63.41%	$ 7,275.71	30.14%	81.09%
6000	$ 6,096.00	$ 4,420.00	-$0.27	$ 4,380.30	$ 1,600.00	-63.47%	$ 7,933.51	30.14%	81.12%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	**$0.5668**
Fuel Adjustor Included in Company Proposed Rate	$0.5668

Typical Bill Analysis
Duncan Rural Services Corp.
Docket No. G-02528A-05-0314
Test Year Ended Dec. 31, 2004

Revised December 15, 2005

EXHIBIT
S-7
Admitted
12-15-05

BASED ON VARIOUS THERM CONSUMPTION LEVELS
Above 250 cfh to 425 cfh

Therm Consumption	Winter Present Rates	Company Winter Proposed Rates	% Change	Summer Present Rates	Company Summer Proposed Rates	% Change	Staff Year Proposed Rates	% Change over winter	% Change over summer
0	$ 22.50	$ 30.00	33.33%	$ 22.50	$ 30.00	33.33%	$ 30.00	33.33%	33.33%
25	$ 47.78	$ 62.42	30.65%	$ 40.63	$ 50.67	24.72%	$ 51.29	7.36%	26.25%
50	$ 73.05	$ 94.84	29.83%	$ 58.75	$ 71.34	21.42%	$ 72.58	-0.64%	23.53%
60	$ 83.16	$ 107.81	29.64%	$ 66.00	$ 79.61	20.61%	$ 81.10	-2.48%	22.87%
70	$ 93.27	$ 120.77	29.49%	$ 73.25	$ 87.87	19.96%	$ 89.61	-3.92%	22.33%
75	$ 98.33	$ 127.26	29.43%	$ 76.88	$ 92.01	19.68%	$ 93.87	-4.53%	22.10%
80	$ 103.38	$ 133.74	29.37%	$ 80.50	$ 96.14	19.43%	$ 98.13	-5.08%	21.89%
90	$ 113.49	$ 146.71	29.27%	$ 87.75	$ 104.41	18.98%	$ 106.64	-6.03%	21.52%
100	$ 123.60	$ 159.68	29.19%	$ 95.01	$ 112.68	18.60%	$ 115.16	-6.83%	21.21%
125	$ 148.88	$ 192.10	29.03%	$ 113.13	$ 133.35	17.87%	$ 136.45	-8.35%	20.61%
150	$ 174.15	$ 224.52	28.92%	$ 131.26	$ 154.02	17.34%	$ 157.74	-9.42%	20.17%
175	$ 199.43	$ 256.94	28.84%	$ 149.38	$ 174.69	16.94%	$ 179.03	-10.23%	19.84%
200	$ 224.70	$ 289.36	28.77%	$ 167.51	$ 195.36	16.62%	$ 200.32	-10.85%	19.59%
250	$ 275.25	$ 354.20	28.68%	$ 203.76	$ 236.70	16.16%	$ 242.90	-11.75%	19.21%
300	$ 325.80	$ 419.04	28.62%	$ 240.02	$ 278.04	15.84%	$ 285.48	-12.38%	18.94%
350	$ 376.35	$ 483.87	28.57%	$ 276.27	$ 319.37	15.60%	$ 328.05	-12.83%	18.75%
400	$ 426.90	$ 548.71	28.53%	$ 312.52	$ 360.71	15.42%	$ 370.63	-13.18%	18.60%
450	$ 477.45	$ 613.55	28.51%	$ 348.77	$ 402.05	15.28%	$ 413.21	-13.45%	18.48%
500	$ 528.00	$ 678.39	28.48%	$ 385.03	$ 443.39	15.16%	$ 455.79	-13.68%	18.38%
750	$ 780.75	$ 1,002.59	28.41%	$ 566.29	$ 650.09	14.80%	$ 668.69	-14.35%	18.08%
1000	$ 1,033.50	$ 1,326.78	28.38%	$ 747.55	$ 856.78	14.61%	$ 881.58	-14.70%	17.93%
1250	$ 1,286.25	$ 1,650.98	28.36%	$ 928.81	$ 1,063.48	14.50%	$ 1,094.48	-14.91%	17.84%
1500	$ 1,539.00	$ 1,975.18	28.34%	$ 1,110.08	$ 1,270.18	14.42%	$ 1,307.38	-15.05%	17.77%
1750	$ 1,791.75	$ 2,299.37	28.33%	$ 1,291.34	$ 1,476.87	14.37%	$ 1,520.27	-15.15%	17.73%
2000	$ 2,044.50	$ 2,623.57	28.32%	$ 1,472.60	$ 1,683.57	14.33%	$ 1,733.17	-15.23%	17.69%
2500	$ 2,550.00	$ 3,271.96	28.31%	$ 1,835.13	$ 2,096.96	14.27%	$ 2,158.96	-15.33%	17.65%
3000	$ 3,055.50	$ 3,920.35	28.30%	$ 2,197.65	$ 2,510.35	14.23%	$ 2,584.75	-15.41%	17.61%
4000	$ 4,066.50	$ 5,217.14	28.30%	$ 2,922.70	$ 3,337.14	14.18%	$ 3,436.34	-15.50%	17.57%
5000	$ 5,077.50	$ 6,513.92	28.29%	$ 3,647.75	$ 4,163.92	14.15%	$ 4,287.92	-15.55%	17.55%

NOTE:

Fuel Adjustor Included in Present Rates	$0.2110
Fuel Adjustor Included in Staff Proposed Rates	$0.5668
Fuel Adjustor Included in Company Proposed Rates	$0.5668