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BEFORE THE ARIZONA CORPORATION C(

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF 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 UNS ELECTRIC, INC.	DOCKET NO. E-04204A-06-0783 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Rate Design Direct Testimony of Jerry D. Anderson and Frank W. Radigan of the Utilities Division in the above matter.

RESPECTFULLY SUBMITTED this 12th day of July 2007.

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DIRECT

TESTIMONY

OF

JERRY D. ANDERSON

FRANK W. RADIGAN

DOCKET NO. E-04204A-06-0783

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.

JULY 12, 2007

Anderson

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

JERRY D. ANDERSON

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 12, 2007

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DEMAND SIDE MANAGEMENT PROGRAMS SUMMARY JDA-1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS Electric" or "the Company") filed an application with the Arizona Corporation Commission ("ACC" or "Commission") for a 5.5 percent increase in its base rates throughout its service territory in the State of Arizona. UNS Electric serves 91,850 customers in its service territory in Mohave County in northwestern Arizona and in Santa Cruz County in southern Arizona.

Included in UNS Electric's application is a request to add new Demand-Side Management ("DSM") programs and to enhance existing DSM programs for residential and commercial customers. Details of the Company's proposed DSM activities were filed in its "Demand Side Management Portfolio Plan 2008 – 2012" in Docket No. E-04204A-07-0365 on June 13, 2007. Recommendations regarding the Company's proposed DSM programs will be made in that proceeding; however, funding for those programs is better dealt with in the context of a rate case and is the subject of this testimony.

In addition, Staff has made recommendations in this testimony regarding changes in the funding for Renewables programs at UNS Electric. Staff's recommendations in this regard are to better position the Company to be responsive to future changes in renewables programs, particularly the coming change from the Environmental Portfolio Standard to the Renewable Energy Standard and Tariff rules.

Having examined relevant portions of UNS Electric's rate case filing and its DSM Portfolio Plan filing, Staff recommends the following:

1. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program.

2. Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.

3. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.

4. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

5. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills.

6. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense.

7. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.

8. Staff recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year.

9. Staff recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year, annually by April 1 of each year.

10. Staff recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 of each year beginning June 1, 2009, if no action is taken by the Commission to modify or reject it.

11. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9.

12. Staff recommends that the EFPS tariff become permanent.

13. Staff recommends that the EFPS surcharge tariff become an adjustor mechanism.

14. Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills.

INTRODUCTION

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

A. My name is Jerry D. Anderson. I am a Public Utilities Analyst V 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 provide recommendations to the Commission on electric and gas rate filings, purchased power and fuel adjustment matters, Demand-Side Management ("DSM") programs, and other energy-related matters as assigned.

Q. Please describe your educational background and professional experience.

A. I graduated from Western Kentucky University, Bowling Green, Kentucky, receiving a Bachelor of Science degree with double majors in Economics and Business Management. My course of studies included classes in micro-economic price theory, macro-economic theory and business cycles, accounting, management, and data processing. I earned an MBA degree from Xavier University, Cincinnati, Ohio, with an area of concentration in multinational business.

After working as a computer programmer for a major oil and refining company, I applied my computer skills to rate research, load research, and load forecasting as a member of the Cincinnati Gas & Electric Company's (later Cinergy/Duke Energy) Rate & Economic Research Department for 15 years. I was promoted to a succession of more responsible positions there and ultimately was named Economist in charge of all electric sales and load forecasting activities. In this position I was responsible for constructing econometric models of the regional economy for the purpose of forecasting electric system peak demands and sales by class of service for a three-state service territory. Since that time, I have served as a consultant and branch manager of two consulting firms providing services to such clients as the State of Arizona and the Los Alamos National Laboratories, Los Alamos, New Mexico. More recently, I have held positions in the government sector and in 2005 was employed by the ACC as a Public Utilities Analyst.

I have participated in various classes on general regulatory and utility issues, including the University of Wisconsin's "Gas Rate Fundamentals" class, New Mexico State University's "Basics" class, and Michigan State University's "Camp NARUC" program. I am a member of the National Association for Business Economics and have testified before the Arizona Corporation Commission.

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

A. In this case, I will address a funding or cost recovery mechanism for DSM at UNS Electric, Inc. ("UNS Electric" or the "Company"). I will also suggest a funding change for Renewables programs at UNS Electric.

Time of Use rates ("TOU"), although included by UNS Electric in this filing as a DSM program, will be addressed in this case by Staff witness, Frank Radigan, as a rate matter and, therefore, costs related to that program will not be included in the DSM funding mechanism. UNS Electric proposed that its Low Income Weatherization Program ("LIW") be removed from base rates to become one of its residential DSM programs. Staff witness, Ms. Julie McNeely-Kirwin, addressed UNS Electric's proposed bill assistance component of the LIW in her Direct Testimony.

Since UNS Electric has filed details of its "Demand Side Management Portfolio Plan 2008 – 2012" ("Portfolio Plan") for Commission approval outside of this rate case (Docket No. E-04204A-07-0365), my focus on DSM at this time will be to make general comments on UNS Electric's DSM activities. I have examined UNS Electric's Portfolio Plan filing to make observations on the scope of the DSM activities contemplated by the Company in order to make appropriate recommendations in this proceeding for DSM cost recovery, but will not address the individual DSM programs in this proceeding. I will make recommendations also regarding cost recovery aspects of renewables programs at UNS Electric, but will not address the individual renewables programs.

Q. Have you reviewed relevant portions of UNS Electric's filing in Docket No. E-04204A-06-0783 submitted by the Company in this case?

A. Yes, I have. I have also examined the Company's DSM Portfolio Plan filed in Docket No. E-04204A-07-0365, but Staff has not completed analysis of the Portfolio Plan or the DSM programs in that portfolio and will make no specific recommendations regarding the Portfolio Plan in this proceeding.

CURRENT DEMAND SIDE MANAGEMENT COST RECOVERY

Current DSM Programs and Funding

Q. What DSM Programs does UNS Electric currently conduct?

A. According to its Semi-Annual Report on Demand Side Management Programs ("semi-annual reports"), UNS Electric currently conducts the following DSM programs:

1. Residential Energy Survey Program
2. Commercial Energy Survey Program
3. Residential New Construction
4. Academic Education

UNS Electric also conducts a Low Income Weatherization ("LIW") program not currently considered DSM, but it is proposing to include LIW as a DSM program.

Q. How are current UNS Electric DSM programs funded?

A. Decision No. 59951, January 3, 1997, allowed $175,000 annually from base rates to fund on-going DSM programs.

Q. Was the LIW program included in that $175,000 DSM funding?

A. No. Decision No. 59951 allowed an additional $70,000 annually from base rates to fund the LIW program which was no longer categorized as DSM as a result of that same rate case.

Q. How much has UNS Electric been spending on DSM activities in recent years?

A. The following is a summary of DSM expenditures reported by UNS Electric in its semi-annual reports. These amounts do not include expenditures on the LIW program.

UNS Electric, Inc. Demand Side Management Costs * 2004 – 2006 (actual)		
2004 - January – June	$20,379	
July – December	$142,715	$163,094
2005 - January – June	$72,098	
July – December	$122,121	$194,219
2006 - January – June	$53,013	
July – December	$101,294	$154,307
* Does not include the LIW Program		

PROPOSED DEMAND SIDE MANAGEMENT COST RECOVERY

Proposed DSM Programs and Funding

Q. What DSM Programs were proposed by UNS Electric in this proceeding?

A. UNS Electric proposed the following DSM programs:

1. TOU Pricing Plans
2. Direct Load Control ("DLC") Program
    a) Air conditioner cycling
    b) Programmable thermostat control
3. Energy Smart Homes Program
4. Shade Tree Program
5. Low Income Weatherization (included as DSM)

Staff also determined that the Company intends to continue or enhance its Residential Energy Survey program, Academic Education program, and Commercial Energy Survey program as components of an Education and Outreach Program.

Q. UNS Electric has proposed moving the LIW program into DSM. Does Staff concur with this proposal?

A. Yes. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program. As a DSM program, however, LIW will need to be proven to be cost-effective or to be modified to become cost-effective like any other DSM program.

Q. Are the DSM Programs proposed in UNS Electric's Portfolio Plan the same as those proposed in the instant proceeding?

A. No. It appears that UNS Electric made significant changes to its DSM plans after the time it made this rate case filing. UNS Electric subsequently filed its DSM Portfolio Plan and related programs in Docket No. E-04204A-07-0365 on June 13, 2007.

Q. Mr. Anderson, what changes to UNS Electric's DSM plans outlined in this rate case filing have come to your attention?

A. In its Portfolio Plan filing, UNS Electric proposed the following three additional DSM programs:

1. Residential HVAC Retrofit Program
2. Education and Outreach Program
3. Commercial Facilities Efficiency Program

The Education and Outreach Program is a new DSM program for UNS Electric which includes five components, three of which have evolved from and are similar to the 1) Residential Energy Survey, the 2) Commercial Energy Survey, and the 3) Academic Education existing DSM programs.

Q. Did you notice any other changes between the DSM plans filed in this case and the more recently filed Portfolio Plan?

A. Yes. The DLC program filed in the Portfolio Plan no longer includes a component to directly cycle air conditioners. It proposes only the Programmable Thermostat Control component of the DLC program which would cycle air conditioners through the thermostat.

UNS Electric also removed $20,000 annually for Emergency Bill Assistance from its estimate of costs for the LIW program. Staff does not consider Emergency Bill Assistance as DSM and, therefore, agrees that Emergency Bill Assistance should not be included with the LIW program if that program is categorized as a DSM program. Staff has indicated that the Emergency Bill Assistance should be included in UNS Electric's Warm Spirits program and that the $20,000 for that component be funded through base rates (see Direct Testimony of Staff witness Julie McNeely-Kirwin, p. 11, line 20 through p. 12, line 21). Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.

Q. Are UNS Electric's Time of Use ("TOU") pricing plans included in the Portfolio Plan?

A. No. They are not. The TOU pricing plans were included by UNS Electric as DSM in this rate case filing, but they are not included as DSM in the Company Portfolio Plan filing. TOU education, however, was included as a component of the Education and Outreach Program in the Company's Portfolio Plan. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds. TOU education will be evaluated by Staff outside this rate case as a component of the Education and Outreach DSM Program when UNS Electric's Portfolio Plan filing is addressed.

Q. Mr. Anderson, would you summarize your understanding of what DSM programs UNS Electric is currently proposing to undertake, subject to Commission approval?

A. Yes. My understanding is that UNS Electric's current DSM plans are to engage in those programs included in its Portfolio Plan filed with the Commission on June 13, 2007 in Docket No. E-04204A-07-0365.

Q. Would you summarize the DSM programs included in that Portfolio Plan?

A. Yes. The following DSM programs are included:

1. Education and Outreach Program
    a) Residential Education
    b) Academic Education
    c) Commercial Education
    d) Time of Use Education
2. Direct Load Control Program
    a) Programmable thermostat control
3. Low Income Weatherization Program
4. Residential New Construction Program
5. Residential HVAC Retrofit Program
6. Shade Tree Program
7. Commercial Facilities Efficiency Program

Q. How much does UNS Electric estimate it will spend on these DSM activities in the next five years?

A. According to UNS Electric's estimated budget information filed in its Portfolio Plan, the following DSM expenditures are anticipated over the period 2008 through 2012. These planned expenditures are estimates only and are contingent upon Commission approval of UNS Electric's DSM programs for which it has made application.

UNS Electric, Inc.
Demand Side Management Costs
2008 – 2012
(estimated)

	2008	2009	2010	2011	2012
Education and Outreach	$170,000	$130,000	$133,900	$137,917	$142,055
Direct Load Control	$1,968,000	$1,288,389	$1,370,300	$1,453,372	$1,537,637
Low Income Weatherization *	$105,000	$108,150	$111,395	$114,736	$118,178
Residential New Construction	$420,000	$432,600	$445,578	$458,945	$472,714
HVAC Retrofit	$300,000	$309,000	$318,000	$327,818	$337,653
Shade Tree Program	$65,000	$66,050	$67,132	$68,246	$69,393
Com. Facilities Efficiency	$400,000	$412,000	$424,360	$437,091	$450,204
TOTAL	$3,428,000	$2,746,189	$2,870,665	$2,998,125	$3,127,834

* LIW cost estimates do not include $20,000 each year for Emergency Bill Assistance

DSM Cost Recovery Considerations

Q. Do the DSM Programs proposed by UNS Electric in its Portfolio Plan comprise the DSM activities for which you are recommending a cost recovery mechanism in this rate case?

A. Generally, yes. While the Portfolio Plan programs are our most current understanding of what UNS Electric is proposing, it is not known at this time which of these DSM programs the Commission will approve or disapprove or when this will occur. In the final analysis, programs could be disapproved, new programs could be added, and proposed programs could be modified either in scope or in concept. Staff's objective is to propose a funding mechanism that would be responsive to those DSM programs and activities that the Commission may ultimately approve for UNS Electric outside of this docket.

Q. How is UNS Electric proposing to recover the costs of its DSM programs following disposition of this rate case?

A. UNS Electric is proposing to exclude DSM costs from base rates and to implement a single line-item per kWh charge on all customers' bills to collect the amount estimated to be spent on DSM during a given year. The per kWh charge is proposed to be calculated simply by dividing annual estimated DSM costs for the next year by the annual estimated kWh sales for that same year. The Company is proposing to adjust the subsequent year's DSM charge to account for any mismatch in a given year's spending and cost recovery.

In responses to Staff Data Requests 13.14 and 13.15, UNS Electric has outlined a modified methodology to calculate the DSM Adjustor rate during the initial period to recognize that this period will be characterized as a "ramp-up" period during which DSM activities will be ramping up to become fully operational. The Company is proposing to include 100 percent of the LIW costs and 25 percent of the costs for the other DSM programs in the calculation of this initial adjustor rate. UNS Electric believes the LIW program can immediately use the additional new funding without significant ramp-up time as the proposed program is little changed. The Company proposes to calculate the initial DSM charge by dividing these costs, reflecting ramp-up DSM activities, by the kWh recorded in the test year.

Q. Is the DSM cost recovery mechanism UNS Electric is proposing a "DSM Adjustor?"

A. Yes, it is. Although UNS Electric has not used that terminology, the mechanism the Company proposes is a DSM adjustor mechanism.

Q. Is it fair to conclude that Staff is in general agreement with UNS Electric regarding the need to establish a DSM adjustor cost recovery mechanism for the Company in this proceeding?

A. Yes. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

Q. What alternatives for recovery of Commission-approved DSM costs did Staff consider?

A. Alternative methods considered by Staff for recovering the cost of DSM program activities at UNS Electric include the following: (1) recovery through base rates with no deferral accounting; (2) recovery through a deferral account; (3) recovery by amortization or capitalization of costs over time; and (4) recovery through a combination method.

Q. Should UNS Electric recover its Commission-approved DSM costs through base rates with no deferral accounting?

A. No. This method, while providing timely recovery, lacks the flexibility to adjust as new programs are added or current programs are expanded between rate cases. This method is what is currently in place for UNS Electric DSM cost recovery, but is not appropriate as we are looking toward rapid, yet uncertain, expansion of DSM activities at UNS Electric. One weakness of this methodology is when actual incurred costs are less than the base rate amount, it can result in ratepayers paying for DSM costs that have not yet been expended by the utility without any true-up.

Q. Should UNS Electric recover its Commission-approved DSM costs through a deferral account?

A. No. Although this method has been used at UNS Electric (Citizens) in the past, it is not considered an appropriate methodology at the present time. UNS Electric is planning to significantly expand its DSM activities and to increase the dollars expended on those activities commensurately. Staff believes those expenditures should be recovered in a more timely manner than this method allows. A deferral account typically does not allow recovery until the next rate case.

Q. Should UNS Electric recover its Commission-approved DSM costs through recovery by amortization or capitalization of costs over time?

A. No. This method treats DSM expenditures much the same as an investment in new plant or equipment where the investment is recovered in rates over time. It has the advantage of lessening the impact of DSM costs by spreading the costs over a period of time which may more closely mirror the time period over which the DSM benefits are realized. In the case of UNS Electric, however, such a methodology is not appropriate at this time when programs are still small or just beginning. It could become appropriate later when DSM programs may be significantly expanded, and costs for the programs could become more burdensome to ratepayers.

Q. Should UNS Electric recover its Commission-approved DSM costs through a combination method?

A. No. The Commission has used a combination DSM funding method for another utility in the past; however, Staff does not believe such a method is appropriate for UNS Electric at this time because of the uncertain levels and timelines for proposed DSM activities. A combination method could, for example, allocate a fixed amount of Commission-approved costs to be recovered annually in base rates, and any approved costs over that amount could be recovered through a DSM adjustor mechanism. This method can exhibit some of the same characteristics of the base rate method and can also be confusing and less than transparent to customers.

Proposed DSM Cost Recovery

Q. What costs should UNS be able to recover through Staff's recommended DSM adjustor mechanism?

A. UNS Electric should be allowed to recover all prudently incurred DSM program and related costs incurred by the Company in connection with Commission-approved DSM programs and activities. Commission approval of budgets for DSM programs and activities will be established initially when the Commission acts on UNS Electric's Portfolio Plan filing. Changes to approved budget levels could be subsequently approved by the Commission in response to Company application(s) for DSM program changes or through independent action of the Commission.

Allowable costs for Commission-approved programs could include, for example; costs for rebates or other incentives including rebate processing, customer training and technical assistance, customer education, program planning and administration, program implementation, program marketing and communications, measurement and evaluation activities, and properly allocated portions of baseline study expenses if and when such a study is approved by the Commission. Actual incurred costs should be itemized in the Company's DSM semi-annual reports, and would be reviewed by Staff.

Q. How should DSM costs be charged to UNS Electric customers?

A. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills. The per kWh charge would be a result of the DSM adjustor mechanism calculation and would be re-calculated annually. Staff believes the individual DSM line-item charge would provide maximum transparency to UNS Electric customers.

Q. How should DSM-related expenses be recorded in the DSM Adjustor account?

A. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense. Within each DSM program or major category sub-account, the further disaggregation by type of expense would separately record rebates and incentives, marketing, direct program implementation, administrative costs, etc.

Q. How should the per kWh DSM adjustor rate be reset each year?

A. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year. Staff further recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year. The disaggregated costs placed in each DSM Adjustor sub-account for the previous year should be summed to a total DSM cost and compared with documented DSM cost recovery that same year to determine the over- or under-collection adjustment needed to modify projected DSM costs for the current year adjustor rate calculation. Staff further recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year. Staff also recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 if no action is taken by the Commission to modify or reject it. If Staff has concerns with the DSM expenses submitted, the DSM revenues collected, or the proposed DSM adjustor rate calculation, Staff will work with the Company to resolve such discrepancies prior to the June 1 effective date. If necessary, Staff would present a proposal to the Commission for a decision.

Q. Why are you recommending that an adjustor rate from this calculation procedure not become effective until June 1, 2009?

A. Under a scenario where Commission approval is granted for the proposed Portfolio Plan DSM activities in 2007, 2008 would be the first full year of spending under the new portfolio of DSM programs at UNS Electric. Under such a scenario, it is likely that most programs would still be ramping-up during 2008 and early 2009, but the new programs should be in effect during that period. The DSM adjustor rate to become effective June 1, 2009, would be the first adjustor rate based upon actual operation (during calendar year 2008) of the DSM programs proposed in the Portfolio Plan.

Q. If the DSM adjustor rate calculated using the proposed procedure does not become effective until June 1, 2009, what DSM Adjustor rate should be used immediately upon the conclusion of this rate case and until June 1, 2009?

A. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated

Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9 (1,606,376,397 kWh). The following table summarizes the estimated DSM costs to be included in the calculation; recognizing that these numbers could change based upon Commission approval, disapproval, or revisions to the contemplated programs:

UNS Electric, Inc. Demand Side Management Costs To be Included in 2009 DSM Adjustor Calculation (estimated)			
	2008 Estimate	Percentage	Included Costs
Education and Outreach	$170,000	25%	$42,500
Direct Load Control	$1,968,000	25%	$492,000
Low Income Weatherization	$105,000	100%	$105,000
Residential New Construction	$420,000	25%	$105,000
HVAC Retrofit	$300,000	25%	$75,000
Shade Tree Program	$65,000	25%	$16,250
Commercial Facilities Efficiency	$400,000	25%	$100,000
	$3,428,000		$935,750

Q. Under this calculation, what would be the level of the initial DSM adjustor rate?

A. The initial DSM adjustor rate would be $935,750 divided by 1,606,376,397 kWh or $0.000583 per kWh. For a residential customer using 866 kWh per month (2006 average usage), this would result in a charge on each monthly bill of $0.50 or about $6.00 per year.

Q. Is this calculation in agreement with what was proposed by UNS Electric in response to STF 13.14?

A. Yes, the calculation is in agreement with UNS Electric's response to STF 13.14.

COST RECOVERY FOR RENEWABLES PROGRAMS

Changes in Renewables Requirements

Q. Why are you introducing the issue of cost recovery for renewables programs in your testimony?

A. Staff is concerned that changes and mandates regarding renewable energy initiatives may require UNS Electric to expand or alter its renewables programs and associated spending in the near future. Staff is interested in ensuring that a funding mechanism flexible enough to adapt to changes which may occur in the future is in place at UNS Electric.

Q. What types of changes are occurring in renewables energy standards and requirements in Arizona?

A. UNS Electric was required to meet the Environmental Portfolio Standard ("EPS") embodied in A.A.C. R14-2-1618 and approved by the Commission in 2001. The EPS required load-serving entities to derive a portion of the retail energy they sell from solar resources or environmental friendly renewable electricity technologies. The portfolio percentage increases annually. It was 1.00 percent in 2005 and became 1.05 percent in 2006 with at least 60 percent from solar resources. The requirement is 1.1 percent for 2007.

Q. Are the EPS rules still in effect?

A. Yes, but the Commission adopted the Renewable Energy Standard and Tariff ("REST") rules on November 14, 2006, in Decision No. 69127. The REST rules are intended to replace the current EPS rules.

Q. What is the status of the REST rules?

A. The Commission submitted its adopted rules to the Office of the Arizona Attorney General for certification. It received that certification on June 15, 2007. The REST rules are expected to become effective 60 days after being received by the Secretary of State to whom they were sent after certification, or on August 14, 2007

Q. Does UNS Electric rely upon renewables programs to meet a portion of its load requirements?

A. Yes. UNS Electric has been engaged in various renewables programs in an attempt to meet its obligations under the EPS. After the REST rules become effective, Staff expects UNS Electric to comply with them.

Current Renewables Cost Recovery

Q. How does UNS Electric currently recover its renewables costs?

A. UNS Electric currently recovers its renewable costs in an EPS surcharge. The Environmentally Friendly Portfolio Surcharge ("EFPS") tariff outlines EPS surcharge amounts assessed monthly to every metered and non-metered retail electric service. The surcharge in the EFPS tariff is currently set at $0.000875 per kWh with monthly caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

Q. How many dollars have been collected by UNS Electric for renewables?

A. During the test year, $538,502 was collected through the EFPS surcharge. Additional funding in the amount of $5,296 was collected during the test year through the Green Watts program which is a voluntary supplemental source of funds for renewables.

Proposed Renewables Cost Recovery

Q. Should renewables programs at UNS Electric continue to be funded through the EFPS tariff?

A. Yes. However, Decision No. 63360 had approved the EFPS on an interim basis, on February 8, 2001, pending true-up in a rate review proceeding in which fair value findings are determined by the Commission. Since the current proceeding would constitute such a rate review proceeding, Staff recommends that the EFPS tariff become permanent. In order to provide more flexibility, however, Staff recommends that the EFPS surcharge tariff become an adjustor mechanism. The initial amount of this adjustor rate would be the same as contained in the current EFPS tariff, including caps. An adjustment mechanism would allow for future funding changes.

The REST rules require each utility to file a tariff within 60 days of the effective date of the REST rules. The REST rules provide for a utility that has an adjustor mechanism to file a request to reset its adjustor rates in lieu of the tariff. Such approved adjustor rates would replace the EFPS surcharge rates in this adjustor mechanism.

Q. How would the adjustor mechanism work?

A. The Company would be able to file an Application for Commission approval to change the renewables adjustor rate and caps. Each Application would be reviewed by Staff, and

Staff recommendations would be made to the Commission. The Commission would approve, disapprove, or modify the Company's application.

Q. If approved, how would the renewables charge under the adjustor mechanism be assessed to customers?

A. The renewables surcharge amount is currently billed as a separate line item on UNS customers' bills. Under the adjustor mechanism, Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills. The renewables charge line item would be separate and distinct from the DSM charge line item which would also appear on customers' bills.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Staff recommendations are as follows:

1. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program.
2. Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.
3. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.
4. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

5. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills.

6. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense.

7. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.

8. Staff recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year.

9. Staff recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year, annually by April 1 of each year.

10. Staff recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 of each year beginning June 1, 2009, if no action is taken by the Commission to modify or reject it.

11. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9.

12. Staff recommends that the EFPS tariff become permanent.
13. Staff recommends that the EFPS surcharge tariff become an adjustor mechanism.
14. Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SCHEDULE JDA-1

DEMAND-SIDE MANAGEMENT PROGRAMS SUMMARY

UNS Electric, Inc. Demand Side Management Programs (Summary)		
Current per Semi-Annual Report	**Proposed in Rate Case**	**Proposed in Portfolio Plan**
		Education and Outreach
Residential Energy Survey	**Residential Energy Survey**	Residential Education
Academic Education	**Academic Education**	Academic Education
Commercial Energy Survey	**Commercial Energy Survey**	Commercial Education
		TOU Education
	Direct Load Control	**Direct Load Control**
	Programmable Thermostat Control	Programmable Thermostat Control
	Air Conditioner Cycling	
	Low Income Weatherization	**Low Income Weatherization**
Energy Smart Homes	**Energy Smart Homes**	**Residential New Construction**
		Residential HVAC Retrofit
	Shade Tree	**Shade Tree**
		Commercial Efficiency
	Time-of-Use Pricing Plan	

Radigan

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	)	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

JULY 12, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

Class Cost of Service Study ("CCOSS") -- The allocation of purchased power is the single largest factor driving the results. To properly allocate this cost, one needs to either entirely exclude all purchased power costs from the cost of service study or thoroughly analyze individual cost components that make up purchased power so as to understand if they are demand related or customer related. Yet, the Company has provided no proof that its allocation method is consistent with the costs incurred. Until this is done, I recommend that the results of the CCOSS not be used for revenue allocation purposes and that any revenue increase be allocated on an equal percentage basis.

Time of Use ("TOU") Rates – Mandatory TOU rates for customers should not be implemented given that most usage for most customers is so small that it would not justify the added expense.

TOU Time Periods – In general the time periods selected by the Company are reasonable and coincide with those in the marketplace and other neighboring utilities.

TOU TIME PERIOD RATE DIFFERENTIALS - While I recognize that these differentials may change with adjustments to the PPFAC mechanism, they were reasonably developed and give the proper price signals to customers to switch usage to the off-peak period.

INCLINING BLOCK RATE STRUCTURE - While I agree with this recommendation in principle to give customers some price signal that the more they use the more it costs to serve, the introduction of the inclining block rates at this time was impractical given the small recommended rate increase and increases in the customer charge.

MERGER OF MOHAVE AND SANTA CRUZ RATES - Given that the current absolute dollar differential in the customer's bill is small, that costs for the Company as a whole are increasing and the small overall rate increase being recommended, I recommend that a complete elimination of the differential not be made at this time. Rather, the customer charge for both counties should be increased and the remaining revenue requirement be recovered from increasing the energy charge of the Mohave County customers.

RESETTING THE PPFAC TO ZERO - Per the problems outlined by Staff Witness Smith and noted in the CCOSS section of my testimony, it is premature to make this change at this time. The rates have been designed, however, to separately show the power supply costs that are currently included in base rates.

CUSTOMER CHARGES – Balancing rate impacts and the cost to serve as indicated by the CCOSS, the customer charge for the Residential Service Class should be increased from $6.50 per month to $7.50 per month, an increase of $1.00 per month, or 15.4 percent. For the Small General Service Class, I recommend that the customer charge increase from $10 per month to $12 per month, an increase of $2.00 per month or 18.3 percent. For the Large General Service Class and the Interruptible Service Class, I recommend that the customer charge be set at $15.50 per month for both the TOU and non-TOU rates. Each of these charges is somewhat below the indicated cost to serve and also limits the rate impacts to customers. For the Large Power Service Class, the CCOSS indicates that the customer component is $2,140 per month but the Company is proposing to keep the customer charge for service at less than 69 kV at $365 per month and for service above 69 kV decreasing the charge from $800 per month to $400 per month. While neither of these proposals comports with the CCOSS, I recommend that they be approved to avoid unnecessary bill increases.

MISCELLANEOUS SERVICE FEES – Staff supports adopting the Miscellaneous Service Fees proposed by UNS Electric. While the Company's cost data for Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays) shows $126.66 as opposed to the $75 proposed by the Company, the Company's proposal to raise these fees from the current level of $60 to the proposed level of $75 reflects a gradual approach to implementing rate changes, which is supported by Staff. The other Miscellaneous Service Fees proposed by the Company are supported by the cost data and should be adopted.

DEMAND CHARGES FOR LARGE GENERAL AND LARGE POWER SERVICE - The CCOSS does not break down cost of service data for the LPS >69 kV or <69 kV nor rate differential between TOU and Non-TOU for LGS. In discovery, I asked the Company to provide the cost basis for its proposal and any associated workpapers or cost studies used to support it. None were given. Given the lack of justification on the Company's part, I recommend no realignment of the demand charge differentials at this time.

INCREASING THRESHOLD FOR LARGE GENERAL SERVICE - The Company's proposal for increasing the threshold for large general service to 7,500 kWh is reasonable and should be adopted. A small general service customer that uses 10,000 kWh per month currently pays approximately $940 per month while under the Large General Service Class it would pay approximately $1,200 per month or 28% higher. Given that there is no change in the physical service being provided to the customer, there is no justification for the increased costs to the large general service rate customer under the current threshold. The Company's proposal should be adopted.

CARES DISCOUNT - Staff Witness Julie McNeely-Kirwan has recommended that the Company's proposal to revise the structure of the CARES discount be rejected and the current CARES discount structure be retained. I have reflected these recommendations in the CARES rate design.

BLACK MOUNTAIN GENERATING STATION – The Company's proposal to increase the average base delivery charge to customers by approximately 0.6 cents per kWh and to make a corresponding decrease of 0.6 cents per kWh to the base power supply rate on June 1, 2008 or the date of commercial operation of Black Mountain Generating Station ("BMGS") described on page 3 of UNS Electric witness Larson's testimony appears to be rate gimmickry and should not be adopted.

INTRODUCTION

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

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Department of Public Service ("DPS") in the Rates and System Planning sections of the Power Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the DPS, I was responsible for directing all engineering staff during major rate proceedings including those relating to integrated resource planning and environmental impact studies. In February 1997, I left the DPS and joined a firm called Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company. In my 25 years of experience, I have testified as an expert witness in utility rate proceedings on more than 50 occasions before various utility regulatory bodies, including this Commission, the Nevada Public Utility Commission, the New York State Department of Taxation and Finance, the Connecticut Department of Utility Control, the

Rhode Island Public Utilities Commission, the Michigan Public Service Commission and the Federal Energy Regulatory Commission.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment FWR-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment FWR-2 shows the recommended rate design and Attachment FWR-3 shows Staff's bill impact analysis, showing the impact of Staff's recommended rates over a variety of representative usage levels for customers in each customer class. Attachment FWR-4 shows Staff's proof of revenue.

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

A. I will address the class cost of service study, revenue allocation and the proposed rate design.

Q. Have you reviewed the rate design proposals submitted by the Company in this case?

A. Yes. I reviewed Company witness, Mr. D. Bentley Erdwurm's testimony. Mr. Erdwurm is sponsoring a number of rate design changes. I also reviewed the testimony of Company witness Kevin P. Larson concerning rate changes related to the Black Mountain Generating Station ("BMGS").

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a Class Cost of Service Study ("CCOSS")?

A. The purpose of a CCOSS or embedded cost of service study ("ECOS") is to assign the historic costs incurred by the utility to each of the service classifications of the utility in order to determine the relative profitability of each of the service classifications to the overall average. By doing this, it allows the analyst to re-allocate revenue responsibility amongst classes so that each of the service classifications are providing their fair share of costs and one service classification is not subsidizing other service classifications. Any re-allocation of revenue responsibility must be tempered by customer impact concerns.

Q. Have you reviewed the CCOSS model and inputs presented by the Company in this proceeding?

A. Yes, the model accurately assigns costs by the assumed allocation factors and summarizes them by function. Schedule G-6, page 3 of 4, shows the results of the classification and allocation for each of the service classifications and the utility as a whole using the claimed rate of return by service classification. Use of the claimed rate of return for each service classification assumes that rates are re-set so that each service classification is providing exactly the same profitability to the utility without regard to customer bill impacts. This is a useful tool to design cost based rates by cost causality (i.e. customer charge, demand charge, etc.).

Q. Please Summarize the Results of the Company's Study.

A. As shown on Schedule G-6, page 3 of 4, the Company's overall revenue requirement of $166,993,986 is comprised of $37,567,388 of demand-related costs, $16,394,769 of customer-related costs and $113,031,829 of energy-related costs. The energy-related costs which make up 68% of UNS's total costs to serve come from just two accounts: Account

555 – Purchased Power and Account 565 – Transmission of Electricity by Others. While these two accounts are classified by the Company as energy-related, they were allocated based on the average and peaks method.

Q. Please describe the Average and Peaks Method.

A. The Average and Peaks Method is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). While there are many theories and methods to allocate production-related plant, the average and peaks method tries to recognize that the system must have both adequate capacity to satisfy demand at the time of the peak and that utilities try to satisfy the energy supply over the course of the year with the most economical supply available. Thus, it is argued that the average and peaks method recognizes that classes of customers should receive some allocation of costs reflecting contribution to peak and an average demand component to recognize that different types of capacity - baseload, intermediate and peaking capacity – are installed depending on energy use and the duration of load. Since baseload capacity generally has a relatively high capital cost, but a relatively low running (incremental O&M and fuel) cost, the average total cost per kWh, which is the sum of capital cost and running cost, from baseload capacity falls as the utilization of the baseload capacity increases.

Q. Given that UNS has so little of its own generation what is the Company's reason for continuing to use the Average and Peaks Method?

A. As explained in the direct testimony of Company witness Erdwurm, UNS believes that the Average and Peaks Methodology is appropriate because power suppliers typically will demand a higher average price to serve a load with high peaks and a low load factor. The

Average and Peaks approach appropriately allocates more cost to customer groups with relatively high coincident peak demand and relatively low system load factor, as opposed to an energy only allocation approach. He explains that an energy-only allocation would lower the assigned cost to a low load factor class, and would result in a perverse price signal that a class' load factor - and therefore a system's load factor - has no bearing on the price demanded by a purchased power supplier.

Q. Do you agree?

A. The theory that Mr. Erdwurm proffers is not correct under today's deregulated wholesale market place. As noted by Company Witness DeConcini, the Company is currently a full requirements customer of Pinnacle West Capital Corporation that runs through May 31, 2008. That contract does in fact provide for all energy and ancillary services to serve the Company's load at a fixed price per MWh. (DeConcini, pages 2 and 3). Thus, an argument could be made that since the Company incurs purchased power costs on a volumetric basis they should be allocated that way as well. At the same time it must be recognized that the contract is set to expire next year so some look should be given to future procurement. The Company states that it has developed a detailed Procurement Plan to ensure that it has the necessary resources and contracts to reliably serve its load after the expiration of that contract. The Company states that the plan provides for a mix of market power purchases, resource acquisitions and contracts to provide the necessary capacity, energy and reserves to meet its load requirements. (DeConcini, pages 3 and 4). In Exhibit MJD-2, the Company illustrates how its supply portfolio will change over time as its existing contract expires. As shown on that exhibit, the supply portfolio changes from year to year with current resources heavily base load now and relying more on peaking resources out in the future.

Q. Please explain how the use of the Average and Peaks Method Impacts the Revenue Allocation and rate design in this case.

A. I will use the Residential Service Classification to illustrate how the allocation of the purchased power costs can impact the cost responsibility as indicated by the Cost of Service Study. Under the Company' proposed Average and Peaks Method, the Residential Service Classification is allocated approximately $58 million of the $106 million in costs for Account 555 Purchased Power. The Large Power Service Class receives a $9.8 million allocation. The result of this allocation method shows that the Residential Class is deficient -- a -3.7 percent rate of return compared to the overall average of 6.2 percent -- and the Large Power Service is providing a return well above the average -- a 34.4 percent return compared to the overall average of 6.2 percent.

If an energy allocation was used, however, the Residential Service Classification would receive an allocation of $53 million and the Large Power Service would receive an allocation of $13.1 million. The change in the allocation is large enough to drive the indicated rate of return for the Residential Service Classification from a negative to a positive and for the Large Power Service from a large positive to a small negative. Account 555 is not the only account that is allocated on the Average and Peaks Method. As noted previously, Account 565 is as well but also all production related plant and transmission related plant.

I am not advocating that all of the purchased power costs be allocated on an energy basis. I am pointing out that this one assumption on how to allocate the largest costs of the utility drives the results of the whole cost of service study. To properly take the results of this into account, therefore, one needs to either entirely exclude all generation costs from the cost of service study or thoroughly analyze individual cost components that make up purchased power so as to understand if they are demand-related or customer-related. Given that the Average and Peaks assumption drives so many of the other allocation factors, the first option cannot be easily done. The second option is essentially what Staff Witness Smith is advocating that a new mechanism for the PPFAC be studied and implemented for the Company. Until such time that the new mechanism is in place, I recommend that the results of the CCOSS not be used for revenue allocation purposes and that any revenue increase is allocated on an equal percentage basis.

Q. Does this recommendation have any impacts on rate design?

A. Yes, as shown on Schedule H-2, page 2 of 2, the Company is proposing to allocate the base power supply amongst service classifications per the results of its cost of service study. Together with Company Witness Erdwurm's recommendation that all purchased power costs be recovered in base rates (Erdwurm, page 21), the assumptions in the cost of service study have a direct impact on the rate design per service classification. Given my recommendation that the results of the cost of service study not be used to reallocate revenues amongst classes, I am also recommending that the results of the cost of service study not influence the design of rates. This is in agreement with Staff Witness Smith's recommendation that the roll-in of the PPFAC not be done without further study. How this recommendation impacts the results of the individual rates for each service classification will be discussed in the rate design section of my testimony.

RATE DESIGN

Q. How is the Rate Design Section of your testimony organized?

A. Given the number of proposed rate design changes and the fact that some of them impact several service classifications, I will first comment on the proposed changes and then follow with a discussion of the Staff's recommended rates bill impacts for each service classification. The base power supply costs for each rate class were unbundled from the delivery service charge except for the Lighting Class. It is impractical to unbundle power supply from an un-metered service classification. The rates and bill impacts are shown on Attachments FWR-2 and FWR-3 respectively. The Staff Proof of Revenue is shown on Attachment FWR-4.

A. Time of Use Rates

Q. Please address the issue of time of use rates ("TOU Rates").

A. The Company is proposing to include TOU rates to provide a stronger price signal to customers to shift load out of the critical peak period. Reducing peak means that less power will be needed when it is most costly. Consequently, less power will have to be purchased from the spot market during peak times. This will result in savings for the Company and its customers. TOU customers who "shave" the peak and "fill in" the off-peak valleys reduce the average price that they pay for electricity. (Erdwurm, page 17).

The Company's proposal is to require TOU rates for all new residential, small general service, and large general service (4000 kW) customers and all new and existing Large Power Service customers.

Q. Do you agree with the Company's proposal?

A. No. While it is true that TOU rates can provide price signals to customers to shift load, not all customers can or will want to do that. In order to make economic sense, a customer should only shift power to off-peak periods when the price differential is large enough to pay for the cost of the new meter. In general, customers with large energy use have the best opportunity to move enough power to off-peak periods to save money and also pay for the new meter. For example, for a meter with a cost of $200 and a carrying charge of 15 percent, the incremental annual cost of a new meter is approximately $30 per year. Using the Summer On-Peak/Off-Peak differentials proposed by the Company (Exhibit DBE-1) for the residential service classification, a customer would have to move over 2,200 kWh of energy during the summer months from on-peak to off-peak. This equates to a shift of almost 400 kWh per month. However, the billing data provided by the Company shows that 30 percent of all bills are for less than 400 kWh in total. In fact, almost 92 percent of all bills are for usage of less than 2,000 kWh per month (Schedule H-5, page 1 of 7). Since most bills are for relatively small amounts of energy, it is very doubtful that the customers could move enough energy from the on-peak period to the off-peak period to justify the meter expense. That said, these are the types of customers who would most likely benefit from a TOU rate design. While only 8 percent of bills are for usage above 2,000, this small amount of bills accounts for over 25 percent of all sales to the Residential Service Classification. These customers are the ones most likely to be able to shift a large amount of usage and a vigorous customer education program should be initiated to get these customers to volunteer to move to TOU rates.

The Small General Service Classification is similar to the Residential Customers. Using the $200 meter example from above, based on the Company's proposed on-peak/off-peak price differential, a customer would have to shift over 2,100 kWh during the summer period to pay for the meter. This equates to a shift in monthly energy use of just over 350 kWh per month. For this service classification, almost 39 percent of all bills are under 400 kWh per month and 84 percent of all bills are for usage under 2,000 kWh per month (Schedule H-5, page 3 of 7). The 16 percent of the bills that are above 2,000 kWh per month account for 49 percent of all usage from the service classification. Again, if this small amount of customers could be tapped, there might be a great potential for shifting usage.

B. Time of Use Periods

Q. Please comment on the Company's proposed determination of TOU periods.

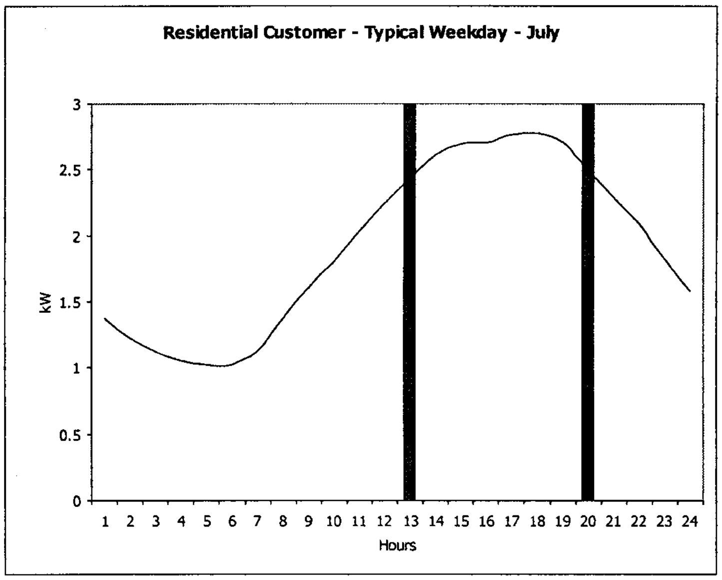
A. The Company is proposing that the Summer Period (May-October) peak be from 2 p.m. to 6 p.m. with a shoulder period on either side of the peak period (Noon to 2 p.m. and 6 p.m. to 8 p.m.), resulting in a total of four hours in the shoulder. Consequently, sixteen hours of each summer day are not peak under UNS's proposal. For the Winter Period (November-April), the Company is proposing a morning peak (6 a.m. to 10 a.m.) and an evening peak (5 p.m. to 9 p.m.), for a total of eight hours per day of winter on-peak. There is no shoulder in the winter. Consequently, sixteen hours of each winter day are also not peak. The Company states that large numbers of off-peak hours offer convenient opportunities for customers to shift usage out of peak and shoulder periods (Erdwurm, page 19).

The Company's proposal is reasonable. The proposed summer peak/shoulder period is sometimes referred to as the super-peak and consists of the hours when energy costs are at their highest. Having a shoulder period within that time frame is an additional benefit because it still encourages customers to move usage away from the Company's peak demand which generally occurs around 4 p.m. As such, even if customers can't move usage to the off-peak period they still might be able to shift usage to the shoulder period which would be a benefit for transmission and capacity planning.

Q. Have you reviewed the TOU time periods of other Arizona utilities?

A. Yes. I examined the TOU rate periods for Arizona Public Service ("APS") and the Salt River Project ("SRP"). APS has two residential TOU options. Schedule ECT-1R has a peak period of 9 a.m. - 9 p.m. Schedule ECT-2 has a peak of 12 noon to 7 p.m. SRP has a peak period of 1 p.m. to 8 p.m. UNS is proposing a shoulder and peak period - Shoulder is 12 noon to 2 p.m. and 6 p.m. to 8 p.m. and a peak of 2 p.m. to 6 p.m. Thus, the total shoulder and peak period proposed where ratepayers are given a higher price signals is from 12 noon to 8 p.m.

While the total time periods are similar to those being used by other Arizona utilities, the UNS proposal is superior because it introduces a shoulder period that gives customers even more flexibility to move load from the peak period (usually 4 p.m. or 5 p.m. for UNS) to the off-peak period or a shoulder period which both saves them money in the short run and broadens the peak for long-term capacity purchases. To illustrate the difficulty that customers might have in shifting load out of the longer on-peak period, below is the usage for a typical UNS customer during July. The vertical bars indicate the beginning and end of the peak period for SRP. As can be seen most of the usage occurs in that seven-hour period, with the peak occurring at 6 p.m. This is intuitive since that's when most people get home. It may be difficult, or troublesome, for most people to shift usage out of the peak period in order to take advantage of lower cost power. For example, since many people with small children find it difficult to change dinner time and some don't want to hear the dishwasher running during prime time, they refrain from taking advantage of lower prices and shifting usage. The introduction of a shoulder period, however, gives more flexibility and can still garner great benefits. For example, as shown on the graph, the typical UNS residential customer uses 2.8 kW between 5 p.m. and 6 p.m. But between 12 p.m. and 1 p.m., the typical usage is 2.4 kW or 14 percent less than the peak period. There is still a large amount of difference and if all of the roughly 77,000 residential customers shifted just half the difference (e.g. through pre-cooling the house before they came home), it would result in a peak usage reduction of almost 15 MW or 3.7 percent of UNS' peak load. Similarly, if these same customers could shift this usage to the 7 p.m. to 8 p.m. time frame when the typical usage is 2.5 kW, the same shifting of half the difference (e.g. running the dishwasher at the time) the shifted usage would result in a shift from peak usage of 12 MW or 2.8 percent of peak. While I don't expect that every residential customer will volunteer for TOU rates and UNS will see these results, the examples do indicate that the addition of shoulder periods do provide the opportunity to realize real benefits from them being there.



C. Time of Use Rate Differentials

Q. Please comment on the Company's proposed time differentiated rate differentials.

A. While I recognize that these differentials may change with adjustments to the Company's PPFAC mechanism, they were reasonably developed and give the proper price signals to customers to switch usage to the off-peak period.

D. Inclining Block Rate Structure

Q. Please discuss the Company's proposal for an inclining block rate structure for the residential and small general service customers.

A. The Company is proposing the introduction of an inverted (or inclining) block structure aimed at encouraging conservation. Residential and small general service customers would now be able to purchase their first 400 kWh per month at a one-cent per kWh discount relative to the second block of consumption (over 400 kWh per month). The Company states that this rate structure would reward customers who are able to conserve for their efforts to conserve electricity. (Erdwurm, page 19).

I agree with this recommendation in principle to give customers some price signal to reflect that the more they use, the more it costs to serve. However, the introduction of the inclining block rates at this time was impractical given the relatively small recommended rate increase and the increases in the customer charge. For instance, for the Small General Service class almost all of the recommended rate increase was recovered through the increase in the customer charge. To implement an inclining block rate structure, in addition to the increases in customer charges, would have resulted in a wide variety of rate impacts, with some customers receiving decreases and some customers receiving increases, that could lead to unnecessary customer confusion. Thus, while implementing inclining block rates in the current case does not appear to be desirable for the practical considerations described above, I would recommend that an inclining block rate design be re-evaluated in the context of the Company's next rate case.

E. Elimination of Separate Rates for Mohave and Santa Cruz

Q. Please discuss the Company's proposal to eliminate separate rates for Mohave and Santa Cruz Counties.

A. As noted in the testimony of Company Witness Erdwurm, rates that differ across a service area are sometimes the result of a prior merger of utility systems. Separate rate structures initially may help avoid "rate shock" associated with an immediate movement to system-wide rates. Mr. Erdwurm suggests that these separate rates should be transitional, not permanent. (Erdwurm, page 20).

While Mr. Erdwurm is correct that the rates should be transitional since the Company is now operating and supplying service as a single entity, "rate shock" should never be ignored but tempered against the goal of uniform rates. In this case, there exists a differential in the energy charge of approximately 0.44 cents per kWh in the energy rates for the Residential and Small General Service Classifications with Mohave County being the less expensive. For a customer using 400 kWh per month in Santa Cruz County, the bill is $45.52 and for a customer in Mohave County the month bill is $43.76. For a customer using 1,000 kWh per month, the monthly bill for a customer in Santa Cruz County is $104.05 per month and $99.65 per month in Mohave County. Given that the current absolute dollar differential in the customer's bill is small, that costs for the Company as a whole are increasing and the relatively small overall rate increase being recommended, it is my position that a complete elimination of the differential not be made at this time. Rather, after increasing the customer charge applicable to customers in both counties as described above in order to give the price signal to customers that costs are increasing, my proposed rate design then left energy rates for Santa Cruz customers at their current levels and recovered the remaining rate increase from the energy charge of the Mohave County customers. This recommendation avoids decreasing the per-kWh charge to Santa Cruz customers and also accomplishes the objective of decreasing the current Santa Cruz-Mohave rate differential significantly for the Residential Service Class to $0.003 per kWh and for the Small General Service Class to $0.043 per kWh. These remaining Santa Cruz-Mohave rate differentials could then presumably be eliminated altogether in the Company's next rate case.

F. Resetting the PPFAC to Zero

Q. Please comment on the Company's proposal to reset the PPFAC to zero, increase base rates for power supply, and separate the rates for the delivery and power supply components.

A. Per the problems outlined by Staff Witness Smith and noted in the CCOSS section of my testimony, it is premature to make this change at this time. The current PPFAC structure reflects costs under the Company's current power supply contract. As such, no change is necessary until a new power supply arrangement is known. Since the current power supply contract will not expire until May 31, 2008 that time is not now. In addition Staff Witness Smith's recommendation that the roll-in of the PPFAC not be done without further study of how the PPFAC mechanism should work heightens my concern that the Company's proposal is premature. The rates have been re-designed to separately show the power supply costs that are currently in base rates.

G. Customer Charges

Q. Please comment on the company's proposed customer charge increases.

A. Per Company witness Erdwurm, the Company is asking to set customer charges at cost-based levels indicated in the CCOSS. The Company states this will help avoid the subsidization of low use customers by high use customers. While the Company understands that conservation of energy is an important policy goal, this must also be balanced with the ratemaking principle that those who cause costs should pay a reasonable share of those costs. The Company states that it seeks to strike this balance through its inverted block rate design and its proposed customer charges. The Company states that its proposed changes to the customer charges result in increases of no more than $2.00 per month. (Erdwurm, page 22).

While the CCOSS presented by the Company does justify the increase in the customer charge proposed for most service classifications, it should also be noted that a large portion of the costs allocated to the customer component is for line transformers. The 1992 NARUC Electric Utility Cost Allocation Manual recognizes that there are various ways to allocate the distribution costs between a demand component and a customer component and it believes that the most accurate method is the use of the minimum intercept method. Under this method, a regression calculation is performed to determine the amount of equipment necessary to just supply service to a customer that uses no power. The zero intercept gives the percent breakdown of costs that should be classified as customer costs. This method would not assign all line transformer costs to the customer component and would tend to reduce the amounts calculated by the Company. That said, the minimum intercept method also applies to other equipment such as poles and services. Under the Company's method, poles are not a customer component and if included would tend to increase the costs calculated by the Company. These effects might offset each other, but it is not known. I recommend that the Company be directed to use both methods in its next cost of service study so as to determine the difference. In the meantime, I recommend using the customer component calculations as presented by the Company.

In designing rates, one must always recognize that setting cost based rates must be tempered against large increase to individual customers. When a utility gets a modest rate increase of say 3 percent and a customer sees a rate increase of 10-15 percent in the customer's own bill, it causes confusion and sometimes resentment at both the utility and the regulatory body. In my experience, when one limits increase or decrease to individual service classification and segments of those customers, customer acceptance of changes increases.

H. Demand Charges for Large General Service and Large Power Service

Q. Please discuss the Company's proposed demand charges for Large General Service and Large Power Service.

A. As testified to by Company Witness Erdwurm, the current demand charge for Large Power Service ("LPS") for service at less than 69 kV is $24.75 / kW-mo. For LPS at service greater than or equal to 69 kV, the demand charge is $16.10 / kW-mo. For Large General Service the current demand charge is $9.50 / kW-mo. According to Mr. Erdwurm, the differentials between these charges are currently overstated, based on costs (Erdwurm, page 23).

The CCOSS does not breakdown cost of service data for the LPS >69 kV or <69 kV. In discovery, I asked the Company to provide the cost basis for its proposal and any associated workpapers or cost studies used to support it. None were given. In addition, the Company's proposal on demand charges appears to be influenced on its proposal to roll all PPFAC costs into base rates. For example, the current energy charges for LPS less than 69 kV total $0.0418 per kWh as compared to the proposed new power supply component proposed of $.0527 per kWh. Since the overall energy charge is increasing by almost 25% it only makes sense that the demand charge would decrease. In fact, the

Company proposed that the demand charge for LPS less than 69 kV be decreased from \$24.75 per kW/month to \$21.53 per kW/month. Given the lack of justification on the Company's part, I recommend no realignment of the demand charge differentials at this time.

I. CARES Discount

Q. Please discuss the Company's proposal for the CARES discount.

A This program allows qualified low income customers to receive discounts. Specifically, the current program provides declining percentage discounts for participating customers, with a flat \$8.00 discount for usage over certain thresholds (1,000 kWh for CARES customers and 2,000 kWh for Medical CARES customers). The Direct testimony of Staff Witness Julie McNeely-Kirwan recommends that the Company's proposal to change the structure of the CARES discount be rejected and the current discount structure be retained. Retaining the current discount method results in an immediate loss of revenue to the Company on the Staff recommended revenue requirement. The lost revenue is less than \$11,000 and is recovered through the rates of all other customer classes. Recovery of CARES lost revenue is reflected in Staff's Proof of Revenue.

J. Threshold for Large General Service

Q. Please comment on the Company's proposal to increase the threshold that causes Small General Service customers to be moved to Large General Service.

A. As explained by Company Witness Erdwurm, Small General Service customers are automatically switched to Large General Service if their usage exceeds 5,000 kWh per month for two consecutive months. When this is done, these customers often end up paying substantially more under the LGS rate, even though the costs to serve them do not rise significantly. Changing the threshold to 7,500 kWh per month will help avoid these automatic switches. Mr. Erdwurm states that customers have expressed concern to the Company about the current threshold, and the Company agrees and recommends the threshold increase (Erdwurm, page 23).

The Company's proposal is reasonable. A small general service customer that uses 10,000 kWh per month currently pays approximately $940 per month while under the Large General Service Class it would pay approximately $1,200 per month or 28% higher. Given that there is no change in the physical service being provided to the customer, there is no justification for the increased costs. The Company's proposal should be adopted.

K. Synchronization of Billing Determinants

Q. Did you encounter any issues with the actual design of the rates?

A. Only one that involved the synchronization of billing determinants between the revenue requirement determination and the rate design. The company made two adjustments to the test year revenues that affected billing determinants; one for customer count and one for weather normalization. These adjustments impact not only the revenue requirement but also the billing determinants to design rates. I reviewed the Company's calculations and they appear reasonable. However, when I priced out the present rates at the billing determinants provided by the Company, they did not exactly match the target revenue requirement. Some classes were too high, and some classes were too low. On a Company-wide basis, the present rates would provide revenues of $157.8 million compared to the target level of $156.7 million. While this is a small difference, 3/4 of one percent, and can be caused by a number of reasons given all the assumptions that go into the calculation, it is important to design rates that will actually produce the intended revenue increase. Otherwise the Company will over-collect or under-collect its revenue requirement. A simple mechanism to ensure that this does not happen is to restate the test year billing determinants so that they agree with the test year revenue target. I did this and then proceeded to design rates to correspond with the Staff recommended revenue requirement.

L. Recommended Rate Design and Related Customer Bill Impacts

Q. Please discuss your recommended rate design and the related customer bill impacts.

A. In the case of the Residential Service Class, I recommend increasing the customer charge from $6.50 per month to $7.50 per month, an increase of $1.00 per month, or a 15.4 percent increase. The CCOSS indicated a monthly customer cost of $12.63 but I wanted to limit the increase to mitigate rate impacts. The energy rate for Santa Cruz County was left unchanged and the portion of the revenue requirement not recovered through the increase in the customer charge was recovered in the energy rate for Mohave County. The bill impacts resulting from this design are shown on page 1 of Attachment FWR-3. For a customer in Mohave County, the minimum bill will increase by $1.00 per month, 15.4 percent, and 2.5 percent for a customer using 1,000 kWh per month. Page 1 of Attachment FWR-3 also shows the bill impacts for customers in Santa Cruz County. The minimum bill will increase by $1.00 per month, 15.4 percent, and 1.0 percent for a customer using 1,000 kWh per month.

Q. Does your recommended rate design reduce the rate differentials between Mohave and Santa Cruz?

A. Yes. The recommended rate design reduces, but does not eliminate, the current rate differentials between Mohave and Santa Cruz. The difference in total electric bills for customers in Mohave and Santa Cruz Counties having the same monthly usage are decreasing significantly under this rate design. As an example, a residential customer in Santa Cruz County using 1,000 kWh per month would have a monthly bill of $105.05 at proposed rates. A residential customer in Mohave County using 1,000 kWh per month would have a monthly bill of $102.19. The differential in bills under proposed rates is $2.86. This compares to the current rate differential of $4.40 per month (Santa Cruz of $104.05 less Mohave of $99.65).

Q. Please explain Staff's proposed rate design for Residential CARES customers.

A. The rate design for the CARES discount remains unchanged; customers continue to receive declining percentage discounts off their bills, with a flat $8.00 discount for usage over certain thresholds. On page 2 of Attachment FWR-3, the bill impacts show that for a customer in Mohave County the minimum bill will increase by $0.70 per month, or 15.4 percent, and $2.01, or 2.8 percent, for a CARES customer using 800 kWh per month. Also, on page 2 of Attachment FWR-3 are the bill impacts for CARES customers in Santa Cruz County. As shown, the minimum bill will increase by $0.70 per month, or 15.4 percent, and $0.90, 1.2 percent, for a CARES customer using 800 kWh per month.

Q. Please explain your proposed rate design for Small General Service customers.

A. For the Small General Service Class, I recommend increasing the customer charge from $10.00 per month to $12.00 per month, an increase of $2.00 per month, or a 20 percent increase. The CCOSS indicated a monthly customer cost of $17.74, but I wanted to limit the customer charge increase to mitigate rate impacts. The energy rate for Santa Cruz County was left unchanged and the portion of the revenue requirement not recovered through the increase in the customer charge was recovered in the energy rate for Mohave County. The bill impacts resulting from this design are shown on page 3 of Attachment FWR-3 and show that for a customer in Mohave County the minimum bill will increase by $2.00 per month, 20 percent, and $3.02, 2.9 percent, for an average customer using 1,000 kWh per month. Also shown on page 3 of Attachment FWR-3 are the bill impacts for customers in Santa Cruz County. As shown, the minimum bill will increase by $2.00 per month, 20 percent, and $2.00, 1.4 percent, for an average customer using 1,000 kWh per month.

The difference in total bills for customers in Mohave and Santa Cruz Counties decreases under this rate design. For the customer using 1,000 kWh per month, the differential in bills under current rates is $43.80 per month – Santa Cruz being higher. The recommended rate design reduces the bill differential to just under $42.77 per month. I believe a gradual approach to reducing the billing differentials, and avoiding rate decreases is preferable to the Company's proposal. Under the proposed rate design, customers in each county still receive an increase which signals to them that the cost of providing electric service is increasing. For customers in Mohave County, the rates overall are increasing by 2.9 percent and for customers in Santa Cruz County the rates overall are increasing by 1.5 percent.

Q. Please explain your proposed rate design for Large General Service customers.

A. For the Large General Service Class, I recommend that the customer charge be set at $15.50 per month for both the non-TOU and TOU rates. For a non-TOU customer, the customer charge increases by $5.40 per month from its current level of $10.10 per month. For a TOU customer, the customer charge increases by $0.50 per month from its current level of $15.00 per month. Each of these charges is somewhat below the indicated cost to serve of $74.61 per month. I elected not to raise the customer charge to the level indicated by the CCOSS but rather collect the revenue requirement in the demand charge. This rate design continues to give the utility steady cash flow but also encourages customers to conserve energy. The energy charge is eliminated with the base power supply cost being unbundled.

The bill impacts shown on Page 4 of Attachment FWR-3 are acceptable with the smallest users, 5,000 kWh per month, in the non-TOU rate class receiving a 3.5 percent rate increase and the largest users, 500,000 kWh per month, receiving a 2.5 percent increase. For the TOU rate class, the smallest users, 5,000 kWh per month, receive a 2.5 percent rate increase and the largest users, 500,000 kWh per month, receive a 2.5 percent increase.

Q. Please explain your proposed rate design for Large Power Service customers.

A. As noted previously, for Large Power Service the CCOSS indicates that the customer component is $2,140 per month (Schedule G-6, page 3 of 4, line 19, column 5). Although the Company's CCOSS shows a customer charge of $2,140 per month for this rate class, the Company is proposing to keep the customer charge for service at less than 69 kW at $365 per month and decreasing the charge from $800 per month to $400 per month for service above 69 kV. To avoid undue bill impacts, I recommend that the Company's proposal be allowed at this time but the customer charge levels should be reviewed for adequacy in the next rate case The Company provided no justification for changing the differential by voltage level in the demand charge for this class; I retained it. In order to unbundle power supply the existing energy charge of $0.236 per kWh was reduced to zero. The revenue requirement not recovered through the increase in the customer charge is recovered in the demand charge.

This rate design decreases the demand charge for customers taking service at less than 69 kV from $24.75 per kW to $10.51, a 58 percent decrease. For a customer taking service at 69 kV and above, the demand charge decreases from $16.10 per kW to $1.86 per kW, an 89 percent decrease. Since the power supply is being stated separately, the cumulative energy charges increase. For all customers in the class the total energy charge (energy rates, base power supply and PPFAC) increases from $0.04185 per kWh to $0.07019 per kWh, a 68 percent increase.

On balance, however, the bill impacts shown on page 5 of Attachment FWR-3 are acceptable with the smallest users, 300,000 kWh per month, in the <69 kV rate class receiving a 0.5 percent rate increase and the largest users, 2,500,000 kWh per month, receiving a 0.5 percent increase. For customers taking service at >69 kV and above, the smallest users, 300,000 kWh per month, in the non-TOU rate class receiving a 3.1 percent rate increase and the largest users, 500,000 kWh per month, receiving a 3.2 percent increase. The customers taking service at >69 kV and above get a slightly higher rate increase as they have a higher load factor (more energy intensive).

Q. Please explain your proposed rate design for Interruptible customers.

A. I recommend that the customer charge be set at $15.50 per month up from its current level of $10.10 per month. The current customer charge is the same as the non-TOU Large General Service Class. The recommended customer charge is also the same as being recommended for the Large General Service class. The recommended customer charge is well below the indicated cost to serve of $46.00 per month. I elected not to raise the customer charge to the level indicated by the CCOSS but rather collect the revenue requirement in the demand charge. This rate design continues to give the utility steady cash flow but also encourages customers to conserve energy. The energy charge is eliminated and replaced with the base power supply charge. The resultant demand charge increases from its current level of $2.50 per kW to $3.40 per kW.

The bill impacts shown on page 6 of Attachment FWR-3 are acceptable with the small users, 10,000 kWh per month, receiving a 2.7 percent rate increase and the large users, 150,000 kWh per month, receiving a 2.1 percent increase.

Q. Please explain your proposed rate design for the Lighting Service Class.

A. No cost information was provided that would indicate that the current cost structure needs to be changed. The Company included a new customer charge of $1.84 per month but gave no justification for it, so I recommend it be rejected. To meet revenue requirement all rates were increased by the class average increase of 2.4 percent. As noted previously the rates for this class cannot have a separate base power supply charge as their usage is un-metered. A comparison of present and proposed rates is shown on page 7 of Attachment FWR-3.

MISCELLANEOUS SERVICE FEES

Q. Please discuss the Miscellaneous Service Fees proposed by UNS Electric and your recommendations for such fees.

A. Staff supports adopting the Miscellaneous Service Fees proposed by UNS Electric. The Miscellaneous Service Fees proposed by UNS Electric, as summarized in the following table, appear to be reasonable. The proposed fees are supported by the Company's cost data with the exception of the Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays). The Company's cost data, which was provided in response to RUCO 1.10, for Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays) shows a cost of $126.66 as opposed to the $75 rate proposed by the Company. However, cost of service information is not the only basis for establishing rates. The Company's proposal to raise these fees from the current level of $60 to the proposed level of $75 reflects a gradual approach to implementing rate changes, which is supported by Staff. The proposed $75 after-hours charge reflects a 25 percent increase over the current charge of $60. Additionally, the proposed after-hours charge of $75 is 150 percent higher than the charge for comparable service performed during regular business hours. The other Miscellaneous Service Fees proposed by the Company are supported by the cost data and should also be adopted as proposed by UNS Electric and Staff:

	STATEMENT OF ADDITIONAL CHARGES	Test Year Fees	Test Year Revenues	Units	Company Proposed Fees	Increased Revenue	Staff Proposed Fees	Increased Revenue	Difference
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
A.	Establishment/Re-establishment of Service	$20.00	$497,235	24,862	$30.00	$248,617	$30.00	$ 248,617	$ -
B.	Reconnection or Connection of Service During Normal Business Hours per Section I	$20.00	$43,800	2,190	$30.00	$21,900	$30.00	$ 21,900	$ -
C.	Reconnection or Connection of Service After Normal Business Hours per Section I	$60.00	$25,568	426	$75.00	$6,392	$75.00	$ 6,392	$ -
D.	After Hours of Service Establishment/Re-establishment (includes weekends and holidays)	$60.00	$32,820	547	$75.00	$8,205	$75.00	$ 8,205	$ -
E.	Meter Reread per Section III	$15.00	$930	62	$20.00	$310	$20.00	$ 310	$ -
	TOTAL ADJUSTMENT TO SERVICE REVENUES					$285,424		$285,424	$0

Source: RUCO 1.10, Income - Service Fees

C&D: Although the Company's cost of service evaluation shows a cost of $126.66 for after hours reconnection and service establishment, the Company and Staff proposed increases to these rate elements reflect a gradual approach to increasing the rates.

BLACK MOUNTAIN GENERATING STATION

Q. Please discuss the Company's proposed rate change relating to Black Mountain Generating Station.

A. The Company proposes to implement a reclassification of rates effective June 1, 2008, or at a later date based on commercial operation, associated with a post test year adjustment to rate base for the BMGS. This proposal is presented in the Direct Testimony of Kevin P. Larson. As a practical matter, this change will have no initial impact on what the customer pays; an average increase in the delivery charge of 0.6 cents/kWh is offset by a decrease in the power supply charge of 0.6 cents/kWh. No change in rate design would be necessary since the Company is proposing simply to move a portion of the base power supply charge to the base delivery charge on a volumetric basis (per kWh).

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment FWR-1

Qualifications of
FRANK W. RADIGAN

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EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies. Wholesale power system modeling with GE-MAPS.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Illion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of he method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes.

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England.

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed Installed $0.17/kW/month Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels, forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member American Public Power Association, Northeast Public Power Association and New York State ISO.

UNS Electric, Inc.
Comparison of Present and Staff Proposed Rates
Test Year Ended June 30, 2006

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service Delivery Charges - Mohave County				
Customer Charge	$6.50	$7.50	$1.00	15.4%
Energy Charge, first 400 kWhs	$0.074900	$0.024497	-$0.0504	-67.3%
Energy Charge, all additional kWhs	$0.074900	$0.024497	-$0.0504	-67.3%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Residential Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Residential Service Delivery Charges - Santa Cruz County				
Customer Charge	$6.50	$7.50	$1.00	15.4%
Energy Charge, first 400 kWhs	$0.079300	$0.027360	-$0.0519	-65.5%
Energy Charge, all additional kWhs	$0.079300	$0.027360	-$0.0519	-65.5%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Residential Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Residential Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.066130		
Summer Shoulder		$0.055750		
Summer off-peak		$0.051130		
Winter on-peak		$0.054820		
Winter off-peak		$0.039820		
Small General Service Delivery Charges - Mohave County				
Customer Charge	$10.00	$12.00	$2.00	20.0%
Energy Charge, first 400 kWhs	$0.074500	$0.023585	-$0.0509	-68.3%
Energy Charge, all additional kWhs	$0.074500	$0.023585	-$0.0509	-68.3%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Small General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Small General Service Delivery Charges - Santa Cruz County				
Customer Charge	$10.00	$12.00	$2.00	20.0%
Energy Charge, first 400 kWhs	$0.118300	$0.066360	-$0.0519	-43.9%
Energy Charge, all additional kWhs	$0.118300	$0.066360	-$0.0519	-43.9%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Small General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Small General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.066550		
Summer Shoulder		$0.055860		
Summer off-peak		$0.051550		
Winter on-peak		$0.055650		
Winter off-peak		$0.040650		

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service Delivery Charges				
Customer Charge	$10.10	$15.50	$5.40	53.5%
Demand Charge, per kW	$9.50	$10.71	$1.21	12.7%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.05	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large General Service TOU Delivery Charges				
Customer Charge	$15.00	$15.50	$0.50	3.3%
Demand Charge, per kW	$9.50	$10.71	$1.21	12.7%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.0533	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.067710		
Summer Shoulder		$0.056330		
Summer off-peak		$0.052710		
Winter on-peak		$0.055950		
Winter off-peak		$0.040950		
Large Power Service (<69KV) Delivery Charges				
Customer Charge	$365.00	$365.00	$0.00	0.0%
Demand Charge, per kW	$24.75	$10.51	-$14.24	-57.5%
Energy Charge (kWhs)	$0.023600	$0.000000	-$0.0236	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large Power Service (>69KV) Delivery Charges				
Customer Charge	$800.00	$800.00	$0.00	0.0%
Demand Charge, per kW	$16.10	$1.86	-$14.24	-88.5%
Energy Charge (kWhs)	$0.023600	$0.000000	-$0.0236	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large Power Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.068850		
Summer Shoulder		$0.056860		
Summer off-peak		$0.053850		
Winter on-peak		$0.056850		
Winter off-peak		$0.041850		

UNS Electric, Inc.
Comparison of Present and Staff Proposed Rates
Test Year Ended June 30, 2006

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service Delivery Charges				
Customer Charge	$10.10	$15.50	$5.40	53.5%
Demand Charge, per kW	$2.50	$3.40	$0.90	36.0%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.0533	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Interruptible Power Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.068310		
Summer Shoulder		$0.056140		
Summer off-peak		$0.053310		
Winter on-peak		$0.055860		
Winter off-peak		$0.040860		
Lighting Dusk to Dawn Delivery Charges				
Existing Wood Pole - Overhead	$0.00	$0.00	$0.00	0.0%
New 30' Wood Pole (Class 6) - Overhead	$4.02	$4.12	$0.10	2.4%
New 30' Metal or Fiberglass - Overhead	$8.05	$8.25	$0.20	2.4%
Existing Wood Pole - Underground	$2.01	$2.06	$0.05	2.4%
New 30' Wood Pole (Class 6) - Underground	$6.04	$6.19	$0.15	2.4%
New 30' Metal or Fiberglass - Underground	$10.06	$10.30	$0.24	2.4%
Wattage, per Watt	$0.053040	$0.054331	$0.001291	2.4%

Utilites Division Staff Recommendation for UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006

Residential Service Delivery Charges - Mohave County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.07490	$0.02450
Energy Charge, all additional kWhs	$0.07490	$0.02450
PPFAC Charge	$0.01825	$0.01825
Residential Service Base Power Supply Charge, all kWhs		$0.05194

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$6.50	$7.50	$1.00	15.4%
50	$11.16	$12.23	$1.08	9.7%
100	$15.82	$16.97	$1.15	7.3%
200	$25.13	$26.44	$1.31	5.2%
400	$43.76	$45.37	$1.61	3.7%
500	$53.08	$54.84	$1.77	3.3%
800	$81.02	$83.25	$2.23	2.8%
1,000	$99.65	$102.19	$2.54	2.5%
2,000	$192.80	$196.87	$4.07	2.1%
2,500	$239.38	$244.22	$4.84	2.0%
5,000	$472.25	$480.94	$8.69	1.8%
10,000	$938.00	$954.37	$16.37	1.7%
Average Increase For Subclass				2.6%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Residential Service Delivery Charges - Santa Cruz County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.079300	$0.027360
Energy Charge, all additional kWhs	$0.079300	$0.027360
PPFAC Charge	$0.018250	$0.018250
Residential Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$6.50	$7.50	$1.00	15.4%
50	$11.38	$12.38	$1.00	8.8%
100	$16.26	$17.26	$1.00	6.2%
200	$26.01	$27.01	$1.00	3.8%
400	$45.52	$46.52	$1.00	2.2%
500	$55.28	$56.28	$1.00	1.8%
800	$84.54	$85.54	$1.00	1.2%
1,000	$104.05	$105.05	$1.00	1.0%
2,000	$201.60	$202.60	$1.00	0.5%
2,500	$250.38	$251.38	$1.00	0.4%
5,000	$494.25	$495.25	$1.00	0.2%
10,000	$982.00	$983.00	$1.00	0.1%
Average Increase For Subclass				1.3%
Average Increase For Service Classification	$2.20		$1.43	2.4%
Overall Average Increase				2.4%

Residential Service Cares - Delivery Charges Mohave County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.074900	$0.024497
Energy Charge, all additional kWhs	$0.074900	$0.024497
PPFAC Charge	$0.018250	$0.018250
Discount	Varies	Varies
Residential Service Cares Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Present Discount	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	30%	$4.55	$5.25	$0.70	15.4%
50	30%	$7.81	$8.56	$0.75	9.7%
100	30%	$11.07	$11.88	$0.81	7.3%
200	30%	$17.59	$18.51	$0.92	5.2%
500	20%	$42.46	$43.87	$1.41	3.3%
600	20%	$49.91	$51.45	$1.54	3.1%
800	10%	$72.92	$74.92	$2.01	2.8%
1,000	10%	$89.69	$91.97	$2.28	2.5%
2,000	$8.00	$184.80	$188.87	$4.07	2.2%
2,500	$8.00	$231.38	$236.22	$4.84	2.1%
5,000	$8.00	$464.25	$472.94	$8.69	1.9%
10,000	$8.00	$930.00	$946.37	$16.37	1.8%
Average Increase For Subclass					2.6%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Residential Service Cares - Delivery Charges Santa Cruz County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.079300	$0.02736
Energy Charge, all additional kWhs	$0.079300	$0.02736
PPFAC Charge	$0.018250	$0.018250
Discount	Varies	Varies
Residential Service Cares Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Present Discount	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	30%	$4.55	$5.25	$0.70	15.4%
50	30%	$7.96	$8.66	$0.70	8.8%
100	30%	$11.38	$12.08	$0.70	6.2%
200	30%	$18.21	$18.91	$0.70	3.8%
400	20%	$36.42	$37.22	$0.80	2.2%
500	20%	$44.22	$45.02	$0.80	1.8%
800	10%	$76.09	$76.99	$0.90	1.2%
1,000	10%	$93.65	$94.55	$0.90	1.0%
2,000	$8.00	$193.60	$202.60	$9.00	4.6%
2,500	$8.00	$242.38	$251.38	$9.00	3.7%
5,000	$8.00	$486.25	$495.25	$9.00	1.9%
10,000	$8.00	$974.00	$983.00	$9.00	0.9%
Average Increase For Subclass					1.3%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Utilites Division Staff Recommendation for UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006

Small General Service Delivery Charges - Mohave County	Present	Proposed
Customer Charge	$10.00	$12.00
Energy Charge, first 400 kWhs	$0.074500	$0.023585
Energy Charge, all additional kWhs	$0.074500	$0.023585
PPFAC Charge	$0.018250	$0.018250
Small General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$10.00	$12.00	$2.00	20.0%
50	$14.64	$16.69	$2.05	14.0%
100	$19.28	$21.38	$2.10	10.9%
250	$33.19	$35.44	$2.26	6.8%
500	$56.38	$58.89	$2.51	4.5%
1,000	$102.75	$105.78	$3.02	2.9%
2,000	$195.50	$199.55	$4.05	2.1%
3,500	$334.63	$340.21	$5.59	1.7%
5,000	$473.75	$480.88	$7.12	1.5%
10,000	$937.50	$949.75	$12.25	1.3%
30,000	$2,792.50	$2,825.25	$32.75	1.2%
50,000	$4,647.50	$4,700.75	$53.25	1.1%
Average Increase For Subclass				2.9%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Small General Service Delivery Charges Santa Cruz County	Present	Proposed
Customer Charge	$10.00	$12.00
Energy Charge, first 400 kWhs	$0.118300	$0.066360
Energy Charge, all additional kWhs	$0.118300	$0.066360
PPFAC Charge	$0.018250	$0.018250
Small General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$10.00	$12.00	$2.00	20.0%
50	$16.83	$18.83	$2.00	11.9%
100	$23.66	$25.66	$2.00	8.5%
250	$44.14	$46.14	$2.00	4.5%
500	$78.28	$80.28	$2.00	2.6%
1,000	$146.55	$148.55	$2.00	1.4%
2,000	$283.10	$285.10	$2.00	0.7%
3,500	$487.93	$489.93	$2.00	0.4%
5,000	$692.75	$694.75	$2.00	0.3%
10,000	$1,375.50	$1,377.50	$2.00	0.1%
30,000	$4,106.50	$4,108.50	$2.00	0.0%
50,000	$6,837.50	$6,839.50	$2.00	0.0%
Average Increase For Subclass				1.5%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Large General Service Delivery Charges	Present	Proposed
Customer Charge	$10.10	$15.50
Demand Charge, per kW	$9.50	$10.71
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	16	$519.86	$537.82	$17.96	3.5%
10,000	32	$1,029.62	$1,060.14	$30.52	3.0%
25,000	80	$2,558.90	$2,627.10	$68.21	2.7%
50,000	160	$5,107.70	$5,238.71	$131.01	2.6%
100,000	320	$10,205.29	$10,461.92	$256.62	2.5%
200,000	640	$20,400.49	$20,908.34	$507.85	2.5%
300,000	960	$30,595.68	$31,354.76	$759.07	2.5%
400,000	1,280	$40,790.88	$41,801.18	$1,010.30	2.5%
500,000	1,600	$50,986.07	$52,247.60	$1,261.52	2.5%
600,000	1,920	$61,181.27	$62,694.02	$1,512.75	2.5%
Average Increase For Subclass					2.4%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Large General Service TOU Delivery Charges	Present	Proposed
Customer Charge	$15.00	$15.50
Demand Charge, per kW	$9.50	$10.71
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	16	$524.76	$537.82	$13.06	2.5%
10,000	32	$1,034.52	$1,060.14	$25.62	2.5%
25,000	80	$2,563.80	$2,627.10	$63.31	2.5%
50,000	160	$5,112.60	$5,238.71	$126.11	2.5%
100,000	320	$10,210.19	$10,461.92	$251.72	2.5%
200,000	640	$20,405.39	$20,908.34	$502.95	2.5%
300,000	960	$30,600.58	$31,354.76	$754.17	2.5%
400,000	1,280	$40,795.78	$41,801.18	$1,005.40	2.5%
500,000	1,600	$50,990.97	$52,247.60	$1,256.62	2.5%
600,000	1,920	$61,186.17	$62,694.02	$1,507.85	2.5%
Average Increase For Subclass					3.0%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Utilites Division Staff Recommendation for UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006

Large Power Service (<69KV) Delivery Charges	Present	Proposed
Customer Charge	$365.00	$365.00
Demand Charge, per kW	$24.75	$10.51
Energy Charge, per kWh	$0.023600	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	587	$27,447	$27,590	$143	0.5%
450,000	880	$40,988	$41,202	$214	0.5%
650,000	1,272	$59,042	$59,351	$309	0.5%
850,000	1,663	$77,096	$77,501	$405	0.5%
950,000	1,859	$86,124	$86,576	$452	0.5%
1,500,000	2,935	$135,773	$136,488	$714	0.5%
1,750,000	3,424	$158,342	$159,175	$833	0.5%
2,000,000	3,913	$180,910	$181,862	$952	0.5%
2,500,000	4,891	$226,046	$227,236	$1,190	0.5%
Average Increase For Subclass					0.5%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Large Power Service (>69KV) Delivery Charges	Present	Proposed
Customer Charge	$800.00	$800.00
Demand Charge, per kW	$16.10	$1.86
Energy Charge, per kWh	$0.023600	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	549	$22,199.60	$22,877.70	$678	3.1%
450,000	824	$32,899.40	$33,916.55	$1,017	3.1%
650,000	1,190	$47,165.80	$48,635.02	$1,469	3.1%
850,000	1,557	$61,432.20	$63,353.48	$1,921	3.1%
950,000	1,740	$68,565.40	$70,712.72	$2,147	3.1%
1,500,000	2,747	$107,797.99	$111,188.50	$3,391	3.1%
1,750,000	3,205	$125,630.99	$129,586.58	$3,956	3.1%
2,000,000	3,662	$143,463.99	$147,984.66	$4,521	3.2%
2,500,000	4,578	$179,129.99	$184,780.83	$5,651	3.2%
Average Increase For Subclass					3.1%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Utilites Division Staff Recommendation for UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006

Interruptible Power Service Delivery Charges	Present	Proposed
Customer Charge	$10.10	$15.50
Demand Charge, per kW	$2.50	$3.40
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,000	34	$809.61	$831.65	$22.04	2.7%
15,000	50	$1,209.36	$1,239.72	$30.36	2.5%
20,000	67	$1,609.11	$1,647.79	$38.68	2.4%
30,000	101	$2,408.62	$2,463.94	$55.33	2.3%
50,000	168	$4,007.63	$4,096.24	$88.61	2.2%
75,000	252	$6,006.39	$6,136.60	$130.21	2.2%
100,000	336	$8,005.15	$8,176.97	$171.82	2.1%
125,000	420	$10,003.92	$10,217.34	$213.42	2.1%
150,000	504	$12,002.68	$12,257.71	$255.03	2.1%

Average Increase For Service Classification	2.4%
Overall Average Increase	2.4%

Lighting Dusk to Dawn Delivery Charges	Present	Proposed	Proposed Increase $	Proposed Increase %
	Overhead Service			
Existing Wood Pole	$0.00	$0.00	$0.00	0.0%
New 30' Wood Pole (Class 6)	$4.02	$4.12	$0.10	2.4%
New 30' Metal or Fiberglass	$8.05	$8.25	$0.20	2.4%
	Underground Service			
Existing Wood Pole	$2.01	$2.06	$0.05	2.4%
New 30' Wood Pole (Class 6)	$6.04	$6.19	$0.15	2.4%
New 30' Metal or Fiberglass	$10.06	$10.30	$0.24	2.4%
Per Watt	$0.053040	$0.054331	$0.0013	2.4%
Base Power Supply, all kWhs		$0.000000		
100 Watts - Overhead				
Existing Wood Pole	$5.30	$5.43	$0.13	2.4%
New 30' Wood Pole (Class 6)	$9.32	$9.55	$0.23	2.4%
New 30' Metal or Fiberglass	$13.35	$13.68	$0.32	2.4%
100 Watts - Underground				
Existing Wood Pole	$7.31	$7.49	$0.18	2.4%
New 30' Wood Pole (Class 6)	$11.34	$11.62	$0.28	2.4%
New 30' Metal or Fiberglass	$15.36	$15.74	$0.37	2.4%
200 Watts - Overhead				
Existing Wood Pole	$10.61	$10.87	$0.26	2.4%
New 30' Wood Pole (Class 6)	$14.63	$14.98	$0.36	2.4%
New 30' Metal or Fiberglass	$18.66	$19.11	$0.45	2.4%
200 Watts - Underground				
Existing Wood Pole	$12.62	$12.93	$0.31	2.4%
New 30' Wood Pole (Class 6)	$16.65	$17.05	$0.41	2.4%
New 30' Metal or Fiberglass	$20.67	$21.17	$0.50	2.4%
400 Watts - Overhead				
Existing Wood Pole	$21.22	$21.73	$0.52	2.4%
New 30' Wood Pole (Class 6)	$25.24	$25.85	$0.61	2.4%
New 30' Metal or Fiberglass	$29.27	$29.98	$0.71	2.4%
400 Watts - Underground				
Existing Wood Pole	$23.23	$23.79	$0.57	2.4%
New 30' Wood Pole (Class 6)	$27.26	$27.92	$0.66	2.4%
New 30' Metal or Fiberglass	$31.28	$32.04	$0.76	2.4%

UNS ELECTRIC, INC
SCHEDULE H SUPPORT - RATES

	A	B	C	D							F		I	J	K
Line No.	Class of Service	Actual Booked BD	Adjustments to Booked BD	Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinants	Adjusted Test Year Revenues	Proposed TY Revenue Increase	Proposed Revenue	New Rates	New Revenues	% Increase
	Residential Service														
1	**Santa Cruz**														
2	Customer Charge	905,171	23,917	929,088	167,236	6.50	$1,087,033		165,871	$1,078,160			7.50	$1,244,031	
3	Energy Charge 1st 400 kWhs	311,809,221	8,872,957	320,682,177	48,102,327	0.07930	$3,814,515		47,709,693	$3,783,379			0.02736	$1,305,337	
4	Energy Charge, all additional kWhs	467,713,831	13,309,435	481,023,266	72,153,490	0.07930	$5,721,772		71,564,539	$5,675,068			0.027360	$1,958,006	
	Delivery Revenue						$10,623,319			$10,536,607					
5	Total Sales	779,523,051	22,182,392	801,705,444	120,255,817										
6	Base Power Supply Charge, all kWhs												0.051940	$6,195,104	
7	PPFAC, all kWhs			801,705,444	120,255,817	0.01825	$2,194,669		119,274,232	$2,176,755			0.018250	$2,176,755	
8	TOTAL RESIDENTAL - SANTA CRUZ						$12,817,988			$12,713,361	$309,346	$13,022,708		$12,879,232	1.3%
9															
10	**Mohave**														
11	Customer Charge	905,171	23,917	929,088	761,852	6.50	$4,952,039		755,634	$4,911,618			7.50	$5,667,252	
12	Energy Charge 1st 400 kWhs	311,809,221	8,872,957	320,682,177	272,579,851	0.07490	$20,416,231		270,354,926	$20,249,584			0.0244970	$6,622,885	
1	Energy Charge, all additional kWhs	467,713,831	13,309,435	481,023,266	408,869,776	0.07490	$30,624,346		405,532,389	$30,374,376			0.024497	$9,934,327	
3	Delivery Revenue	$78,397,054	2,186,829	$80,583,883			$55,992,616			$55,535,578				$22,224,463	
4	Total Sales	779,523,051	22,182,392		681,449,627										
5	Base Power Supply Charge, all kWhs												0.051940	$35,105,587	
	PPFAC, all kWhs			801,705,444		0.01825	$12,436,456		675,887,315	$12,334,943			0.018250	$12,334,943	
7	TOTAL RESIDENTAL - MOHAVE						$68,429,072			$67,870,522	$1,651,450	$69,521,972		$69,664,994	2.6%
8															
9	TOTAL RESIDENTAL SERVICE REVENUE				801,705,444		$81,247,060	$80,583,883		$80,583,883	$1,960,796	$82,544,679		$82,544,226	2.4%
	Small General Service														
11	**Santa Cruz**														
	Customer Charge	87,649	2,265	89,914	23,674	10.00	$236,740		23,671	$236,711			12.00	$284,054	
	Energy Charge 1st 400 kWhs	35,729,532	682,482	36,412,014	8,738,883	0.11830	$1,033,810		8,737,827	$1,033,685			0.06636	$579,842	
13	Energy Charge, all additional kWhs	53,594,298	1,023,723	54,618,021	13,108,325	0.11830	$1,550,715		13,106,741	$1,550,527			0.06636	$869,763	
15	Total Sales	89,323,830	1,706,205	91,030,034	21,847,208				21,844,568						
14	Delivery Revenue	$10,106,565	$191,274	$10,297,839	$3,285,813										
16	Base Power Supply Charge, all kWhs												0.051940	$1,134,607	
17	PPFAC, all kWhs			91,030,034	21,847,208	0.01825	$398,712		21,844,568	$398,663			0.018250	$398,663	
19	Total Santa Cruz			$10,297,839	$3,285,813		$3,219,976			$3,219,587	$78,340	$3,297,927		$3,266,929	1.5%
20															
22	**Mohave County**			13,108,325											
24	Customer Charge	87,649	2,265	89,914	66,240	10.00	$662,400		66,232	$662,320			12.00	$794,784	
	Energy Charge 1st 400 kWhs	35,729,532	682,482	36,412,014	27,673,130	0.07450	$2,061,648		27,669,786	$2,061,399			0.02359	$652,592	
13	Energy Charge, all additional kWhs	53,594,298	1,023,723	54,618,021	41,509,696	0.07450	$3,092,472		41,504,679	$3,092,099			0.02359	$978,888	
14	Total Sales	89,323,830	1,706,205		69,182,826				69,174,464						
15	Delivery Revenue	$10,106,565	191,274	$10,297,839	$7,012,026										
	Base Power Supply Charge, all kWhs												0.051940	$3,592,922	
18	PPFAC, all kWhs			91,030,034	69,182,826	0.01825	$1,262,587		69,174,464	$1,262,434			0.018250	$1,262,434	
	Total Mohave			$10,297,839	$7,012,026		$7,079,107			$7,078,251	$172,231	$7,250,482		$7,281,619	2.9%
20															
21	TOTAL SMALL GENERAL SERVICE REVENUE				$10,297,839		$10,299,083	$10,297,839		$10,297,839	$250,571	$10,548,409		10,548,549	2.4%
22															

	A	B	C	D							F		I	J	K
Line No.	Class of Service	Actual Booked BD	Adjustments to Booked BD	Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinents	Adjusted Test Year Revenues	Proposed TY Revenue Increase	Proposed Revenue	New Rates	New Revenues	% Increase
23	**LARGE GENERAL SERVICE**														
24	**Delivery Charges**														
	Customer Charge	24,021	280	24,301		10.10	$245,440		24,050	$242,901			15.50	$372,769	
	Demand Charge, per kW	1,410,360	16,520	1,426,880		9.50	$13,555,357		1,412,119	$13,415,134			10.71	$15,123,798	
25	Energy Charge (kWhs)	488,503,189	2,743,092	491,246,281		0.0533	$26,183,427		486,164,590	$25,912,573			0.00000	$0	-49.70%
26															
27	Revenue	$48,221,859	250,518	$48,472,376											
28															
29	**LARGE GENERAL SERVICE (TOU)**														
	Delivery Charges														
30	Customer Charge	154	(34)	120		15.00	$1,800		119	$1,781			15.50	$1,841	
31	Demand Charge, per kW	14,246	(3,162)	11,084		9.50	$105,299		10,969	$104,209			10.71	$117,482	
32	Energy Charge (kWhs)	3,691,460	(787,745)	2,903,715		0.0533	$154,768		2,873,678	$153,167			0.00000	$0	-44.88%
33															
34	Revenue	$358,864	-76,527	$282,337											
35	**Base Power Supply Charge, all kWhs**												0.051940	$25,400,648	
36	**PPFAC, all kWhs**			494,149,996		0.01825	$9,018,237		489,038,268	$8,924,948			0.018250	$8,924,948	
37	TOTAL LARGE GENERAL SERVICE REVENUE			$48,754,713			$49,264,328	$48,754,713		$48,754,713	$1,186,317	$49,941,031		$49,941,486	2.4%
38															
39	**LARGE POWER SERVICE (<69KV)**														
40	**Delivery Charges**														
41	Customer Charge	69	6	75		365.00	$27,375		75	$27,290			1000.00	$74,768	
42	Demand Charge, per kW	74,564	6,484	81,047		24.75	$2,005,921		80,797	$1,999,726			10.34	$835,603	
43	Energy Charge (kWhs)	39,094,759	2,287,280	41,382,039	69%	0.02360	$976,616		41,254,230	$973,600			0.000000	$0	-55.69%
44															
45	Revenue	$3,782,246	210,575	$3,992,821											
46															
47	**LARGE POWER SERVICE (>69KV)**														
	Delivery Charges														
48	Customer Charge	64	5	69		800.00	$55,200		69	$55,030			1000.00	$68,787	
49	Demand Charge, per kW	267,616	20,908	288,524	2,290	16.10	$4,645,228		287,632	$4,630,881			1.69	$486,674	
50	Energy Charge (kWhs)	157,105,746	138,971	157,244,717	2,180,556	0.0236	$3,710,975		156,759,064	$3,699,514			0.00000	$0	-69.62%
51															
52	Revenue	$10,990,900	16,063	$11,006,963											
53	Total kWhs	196,200,505	2,426,251	198,626,756											
54	**Base Power Supply Charge, all kWhs**												0.051940	$10,284,810	
	PPFAC, all kWhs			198,626,756		$0.01825	$3,624,938		198,013,294	$3,613,743			0.018250	$3,613,743	
55															
56	TOTAL LARGE POWER SERVICE REVENUE			$14,999,784			$15,046,254	$14,999,784		$14,999,784	$364,980	$15,364,764		$15,364,385	2.4%
57															
58	**INTERRUPTIBLE POWER SERVICE**														
59	**Delivery Charges**														
60	Customer Charge	235	0	235		10.10	$2,374		236	$2,379			15.50	$3,651	
61	Demand Charge, per kW	63,585	0	63,585		2.50	$158,964		63,732	$159,330			3.40	$216,689	
62	Energy Charge (kWhs)	17,598,914	0	17,598,914		0.0533	$938,022		17,639,506	$940,186			0.000000	$0	
63															
64	Revenue	$1,423,816	0	$1,423,816											
65	**Base Power Supply Charge, all kWhs**												0.051940	$916,196	
66	**PPFAC, all kWhs**			17,598,914		$0.01825	$321,180		17,639,506	$321,921			0.018250	$321,921	
67	TOTAL INTERRUPTIBLE POWER SERVICE REVENUE			$1,423,816			$1,420,539	$1,423,816		$1,423,816	$34,645	$1,458,461		$1,458,457	2.4%
68															
69	**LIGHTING DUSK TO DAWN**														
70	Existing Wood Pole - Overhead	38,757	520	39,277		0.00	$0								
71	New 30' Wood Pole (Class 6) - Overhead	8,111	109	8,220		4.02	$33,043		8,846	$35,563			4.12	$36,428	
72	New 30' Metal or Fiberglass - Overhead	2,353	32	2,385		8.05	$19,196		2,566	$20,660			8.25	$21,162	
73	Existing Wood Pole - Underground	677	9	686		2.01	$1,379		738	$1,484			2.06	$1,520	
74	New 30' Wood Pole (Class 6) - Underground	342	5	347		6.04	$2,094		373	$2,253			6.19	$2,308	
75	New 30' Metal or Fiberglass - Underground	7,545	101	7,646		10.06	$76,923		8,230	$82,789			10.30	$84,804	

	A	B	C	D							F		I	J	K
Line No.	Class of Service	Actual Booked BD	Adjustments to Booked BD	Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinents	Adjusted Test Year Revenues	Proposed TY Revenue Increase	Proposed Revenue	New Rates	New Revenues	% Increase
76	Wattage, per Watt	7,762,533		7,866,778		0.053040	$417,254		8,466,756	$449,077			0.05433	$460,004	
77	Revenue	583,672	8,153	$591,825											
78		3,219,530	45,722	3,265,253											
79	Total Number of Units	57,784													
80	**Base Power Supply Charge, customer charge**			58,560		1.84									
81															
82	TOTAL LIGHTING DUSK TO DAWN REVENUE			$591,825			$549,887	$591,825		$591,825	$14,401	$606,226		$606,226	2.4%
83															
84															
85															
86	Customers	1,075,147	27,215	1,102,362											
87	kWhs	1,578,060,479	28,315,918	1,606,376,397											
88	Total Revenue	#REF!	#REF!	#REF!			$157,827,151			$156,651,860	$3,811,710	$160,463,570		$160,463,329	
89	Base Power Supply Revenue Requirement														
90	Total Delivery Revenue Requirement														
91	Total Delivery Revenue Requirement Increase										$3,811,710	$160,463,570			
92	Percent Increase										2.42%				
93	TOTAL UNS ELECTRIC REVENUE REQUIREMENT														