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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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MARCIA WEEKS
Chairman
RENZ D. JENNINGS
Commissioner
DALE H. MORGAN
Commissioner

IN THE MATTER OF THE A.A.C R14-2-704 HEARING FOR RESOURCE PLANNING.	DOCKET NO. U-0000-93-052 **NOTICE OF FILING**

Arizona Corporation Commission Staff ("Staff") hereby files in the above captioned docket its draft Staff Report on the topic of load forecasting plus the overview volume.

The draft Staff Report on the topics of historical data, demand side management, and supply issues, plus the appendix were filed in this docket on September 30, 1993.

Dated this 7th day of October, 1993.

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7th day of October, 1993,
with:

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ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION

STAFF REPORT ON RESOURCE PLANNING: LOAD FORECASTING

D R A F T

September 1993

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**STAFF REPORT ON RESOURCE PLANNING:
LOAD FORECASTING**

In 1989, the Arizona Corporation Commission adopted rules for resource planning. These rules require electric utilities with generating facilities to submit resource plans every three years. The utilities subject to the resource planning rules are Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), Arizona Electric Power Cooperative (AEPCO), a generating and transmission cooperative, and Citizens Utilities Company (CUC). In addition, Salt River Project (SRP) has voluntarily participated in the Commission's resource planning process to help the Commission develop a statewide overview of electric utility issues.

The current resource plans were due to be filed with the Commission on December 31, 1992, although some were filed later to allow the utilities to complete their analyses. Copies of the utility filings may be found in Docket Control, in Docket No. U-0000-93-052.

This volume is one of six volumes of the Commission Staff's 1993 resource planning report. The six volumes are:

1) Introduction and Overview
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STAFF REPORT ON RESOURCE PLANNING:
LOAD FORECASTING

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STAFF REPORT ON RESOURCE PLANNING -- LOAD FORECASTING

Introduction

Load forecasting is a pivotal element of resource planning. The load forecast drives the selection of supply and demand side resources over the planning horizon. However, any forecast, especially one that makes predictions twenty years in the future, will be in error. Hence, utilities sometimes make a range of forecasts to develop a flexible set of plans to deal with uncertainty about the future.

The Commission Staff develops a set of load forecasts as an independent check on utility forecasts. In his review of planning disasters, Peter Hall [1980, p. 268] has argued that multiple teams of experts in a variety of fields should conduct analyses and criticize each other's work to "guard against too easy acceptance of some single orthodox interpretation." The purpose of the Staff forecasts is not to argue that one forecast is right and the other wrong, but to ascertain whether the base case forecasts of the utilities are reasonable given forecasts on population, employment, and other factors and given historical trends in factors affecting the demand for electricity. If the Staff forecasts are consistent with the utility forecasts, we infer that there are no readily apparent factors that we expect would cause utility demand to greatly deviate from forecasted future demand. If the Staff forecasts are not consistent with utility forecasts, we infer that at least one set of forecasts has not properly considered available information or that the utility is facing a very uncertain future.

Sherman Maisel, who served as a governor of the Federal Reserve Board, noted that constant monitoring of data is necessary to make mid-course corrections in plans, because it is not possible to forecast aspects of complex systems accurately: "Given the high risks of playing against nature, we may be far better off minimizing our costs by developing better control and feedback systems rather than trying to improve systems which will be efficient only if the forecasts are completely correct," [quoted in Kamarck, 1983, p. 128]. Thus, utility resource plans should provide sufficient flexibility to deal with the uncertainty inherent in load forecasts.[1]

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[1] Fischhoff et al. [1981, pp. 53-59] identified the qualities desired of an approach to making acceptable risk decisions and most of these qualities are applicable to resource planning under uncertainty: *comprehensiveness*, including a full review of risks, costs, benefits, options, consequences, values, and data sources; *logical soundness*, providing a logically defensible argument consistent with the data, values, and theory, in an objective, reproducible manner; *practicality*, meaning that the methods used be pragmatic, applicable to the problem at hand, to be applied by real people under actual resource constraints; *openness to evaluation*, to ensure that important assumptions, values, etc. are not swept under the rug; *compatibility with institutions*, especially the utility and regulatory institutions affecting the production and delivery of electricity; and *conduciveness to learning*, so that changes in plans can be made as the evidence warrants.

Summary of Utility Load Forecasts

The utilities' long range forecasts of retail MW demand show that growth rates are expected to average between about 2 and 3 percent per year between 1993 and 2002, except for Citizens, which expects an average annual growth rate of 3.9 percent (Table 1). Growth rates in energy sales (megawatt hours) are forecast to be between 2 and 3 percent per year on average for the period 1993 to 2002, except for Citizens' energy sales which are forecast to grow by an average of 4.3 percent per year (Table 2). Note that AEPCO's forecasts of retail demand by Class A members are affected by the expected loss of a large mining load in 1998. Demand figures assume no additional DSM; thus demand pertains to the demand for electric energy services which can be met through production of electricity or demand side management.

Table 1
Utility Forecasts of Growth Rates of Retail Demand (MW)

Utility	Time Period	Average Annual Compound Growth Rate (%)
AEPCO*	1993 - 2002	2.0
APS	1993 - 2001	3.1
Citizens	1993 - 2002	3.9
SRP	1993 - 2002	2.6
TEP	1993 - 2002	2.9

* Pertains to retail sales by Class A members.

Staff Forecasting Analyses

<u>Staff's Econometric Forecasts</u>. We conducted analyses of demand for the period 1993 to 2002 to provide an independent assessment of future demand. We used utility filings for historical consumption data and other sources such as the Department of Economic Security for historical population and employment data. Our principal demand forecasting approach was econometric models of MWh sales. Due to limited time and data availability, we have not completed forecasts using our end use model.

Table 2
Forecasts of Growth Rates of Retail Energy Sales

Utility	Time Period	Average Annual Compound Growth Rate (%)	
		Utility Forecasts	Staff Forecasts
AEPCO*	1993 - 2002	2.1	2.2
APS	1993 - 2001	2.8	3.0
Citizens	1993 - 2002	4.3	4.6
SRP	1993 - 2002	2.7	2.4
TEP	1993 - 2002	2.9	2.2

* Pertains to retail sales by Class A members. Staff forecast excludes Anza.

Our econometric forecasts are compared with the utility forecasts in Figures 1 through 6. As stated above, demand is defined to be the demand for electric energy services which includes demand met by electricity production and by demand side management. Thus, retail sales are analyzed without the effects of additional planned demand side management. We conclude that APS's, SRP's, and Citizens' forecasts are consistent with ours. TEP's forecast, however, shows a considerably higher growth rate than ours in the first five years, which appears to be due to TEP's relatively high industrial sales forecast for that period. This may indicate that TEP is facing greater uncertainty about future demand than some of the other utilities. We invite TEP to help clarify the gap between the forecasts for industrial sales.

AEPCO's forecast for retail sales by Class A members, (Figure 5) is also consistent with ours. The difference between the Staff and AEPCO forecasts in Figure 5 may be largely attributable to Anza's demand; we excluded Anza from our forecast but AEPCO's forecast includes Anza. Alternative forecasts should be considered for AEPCO to reflect uncertainty about future mining load. AEPCO's forecast incorporates a new mining customer in 1997 and the loss of a mining customer in 1998. Figure 6 illustrates three alternative Staff forecasts. Forecast A assumes that existing mining customers are retained and no new mining customers are added. Forecast B assumes loss of an existing mining customer and no new mine is added. Forecast C assumes that existing mining customers are retained and that one new mine is added.

Figure 1

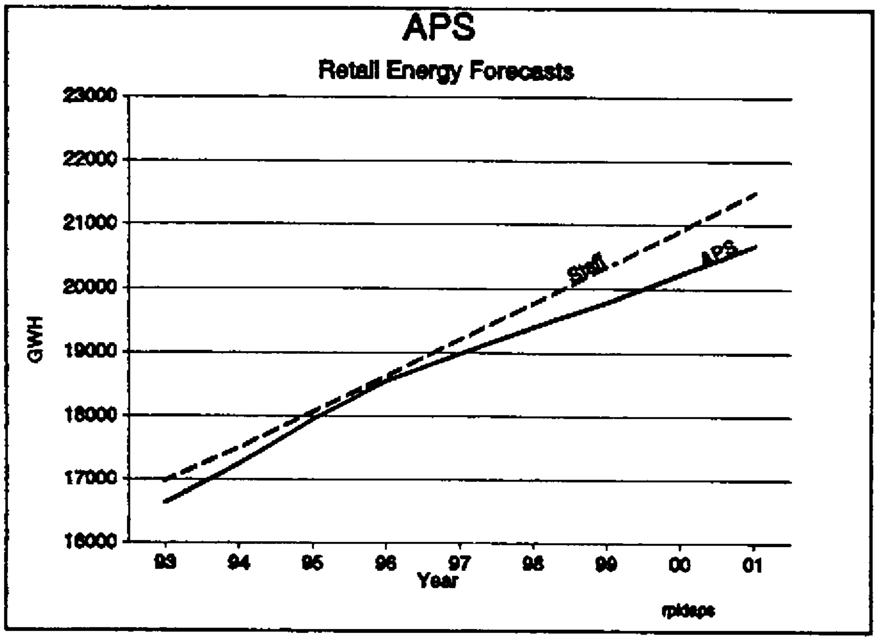


Figure 2

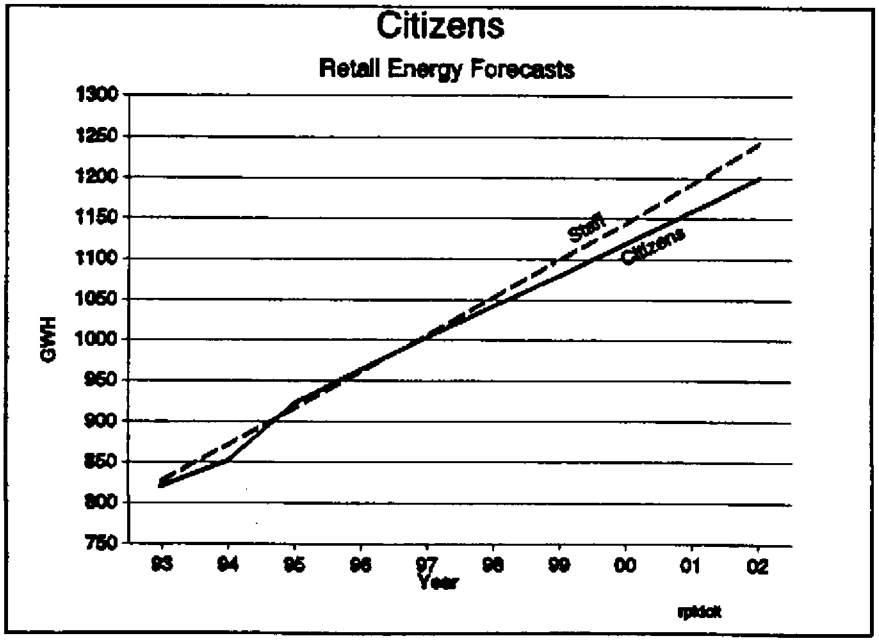


Figure 3

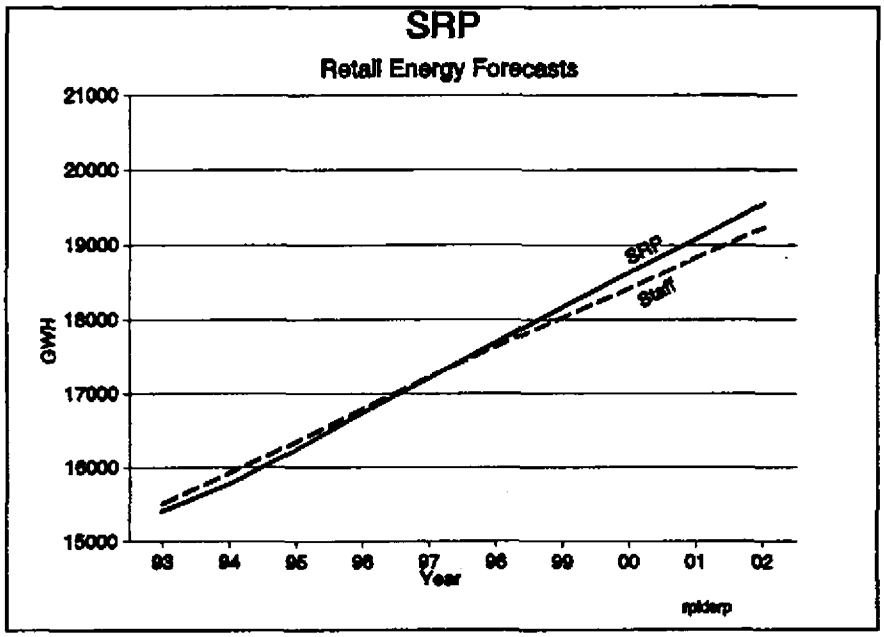


Figure 4

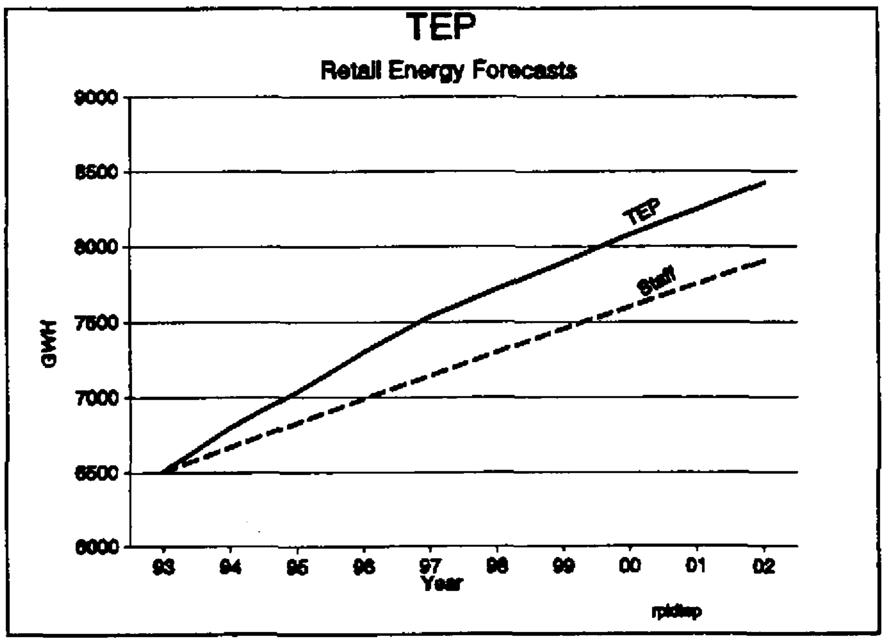


Figure 5

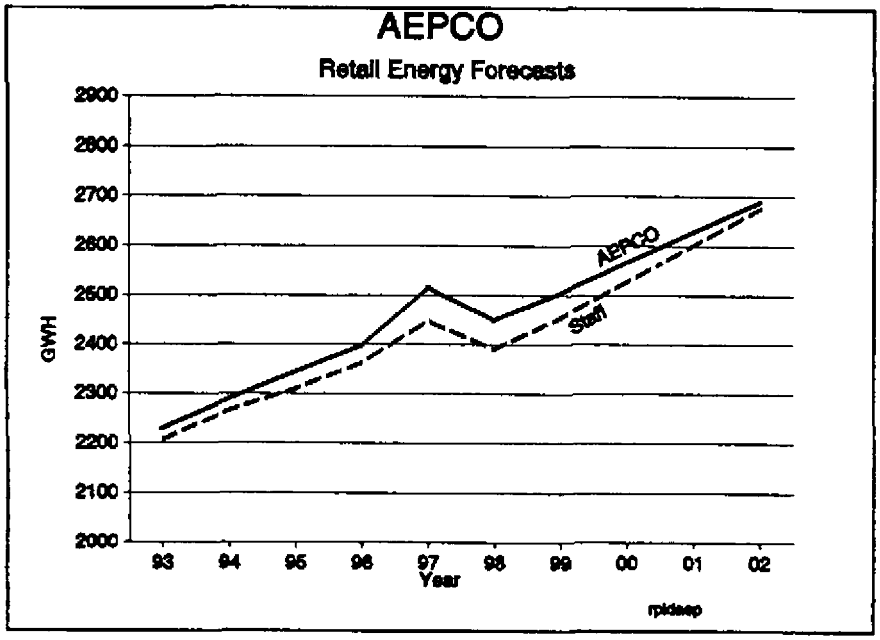
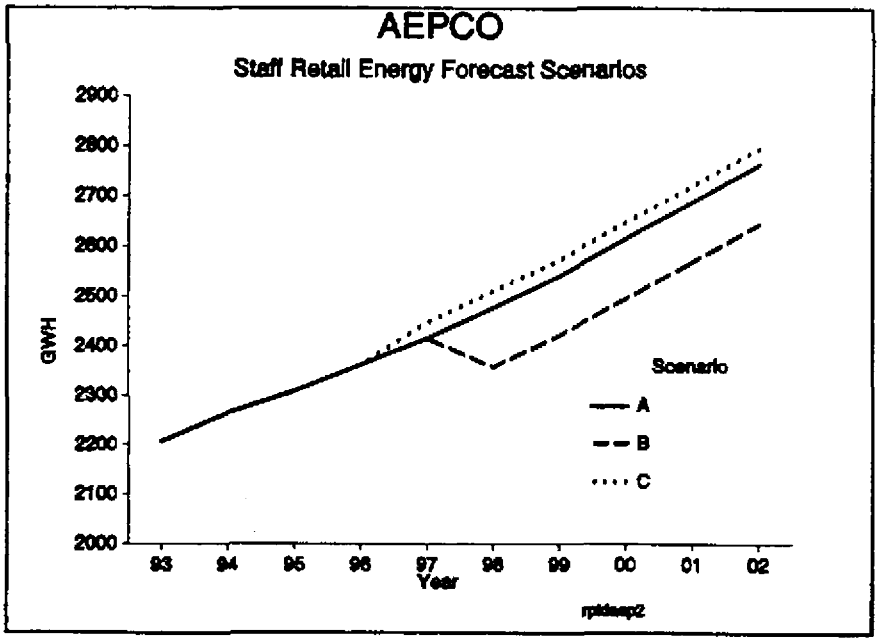


Figure 6



Our expected growth rates for each utility's sales are included in Table 2. We expect sales growth to average between 2.2 percent to 3 percent per year, excluding Citizens. Citizens' growth is considerably higher than the other utilities due to continued high customer growth in the Mohave area. The growth rates are within 0.3 percentage points of the utilities' energy forecasts with the exception of TEP. TEP's forecasted growth in the first 5 years is considerably higher than Staff's, but in the remaining years the TEP and Staff growth rates are about the same, as indicated by the slopes of the lines in Figure 4.

Staff's Econometric Forecasting Models. The framework of our econometric model is a regression analysis for each utility that explains electric demand (megawatt hour sales) as a function of determinants of consumption, such as electricity and gas prices, weather, population, and employment. Regression equations were estimated on time series using SAS Econometric Time Series programs.[2] We prepared forecasts of total retail sales based upon both annual data and monthly data. Forecasts were also prepared by customer class for APS, TEP, and Trico Electric Cooperative, one of AEPCO's member cooperatives.[3] Generally, no significant differences occurred between annual versus monthly forecasts, or between total retail versus aggregated customer class forecasts. Results of the regressions with the strongest results are presented in Tables 3 through 7.

The dependent variables are megawatt hour sales for the customer class indicated in the tables. The tables also indicate whether monthly or annual data were used in the regression model. Data sources for megawatt hour sales are utility historical data filings, utility annual reports, and monthly utility fuel reports.

The key variables used to forecast MWh sales are typically cooling degree days and heating degree days (CDDs and HDDs), employment, number of customers,[4] and energy prices.[5] Nonutility data sources are indicated at the end of this report. Annual

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[2] The Yule-Walker method was used to estimate the time series equations and make corrections for auto-correlation.

[3] AEPCO's retail load (in Arizona) is the sum of the retail loads for Trico, Sulphur Springs Valley, Graham County, Mohave, and Duncan Valley Electric Cooperatives.

[4] Data on number of customers were obtained from utility historical data filings and monthly fuel reports.

[5] Gas prices are expressed in constant 1987 dollars per thousand cubic feet and electricity prices are cents per kilowatt hour in constant 1987 dollars. Gas and electric prices are average annual prices. Data sources for electric utilities are utility historical data filings for resource planning, utility annual reports, and monthly utility fuel reports. Data sources for gas utilities are utility annual reports. We expect that the coefficient of the price

employment and population forecasts were obtained from the Arizona Department of Economic Security (February 1993). We used historical monthly employment data from the Department of Economic Security to estimate seasonally adjusted monthly employment.[6]

In some cases a time trend was used, in which the first period is 1, and subsequent periods are numbered sequentially. We adjusted cooling and heating degree days to utility billing cycles and weighted utility populations in weather areas served. Normal weather (defined here as a 10 year average of CDDs and HDDs) is used to forecast sales.[7] We also analyzed number of customers by regressing the annual number of customers on population and a trend variable and then applied this relationship to forecast the number of customers. Finally, we assumed that electricity and natural gas prices would remain constant in real dollars over the forecast period.

Conclusions and Recommendations

We find that, with exception of TEP, our load forecasts are consistent with the utility forecasts for the next ten years. The differences between the Staff and TEP forecasts may be due to considerable uncertainty about industrial development in TEP's service area. We invite TEP to help clarify the gap between the forecasts for industrial sales. Because TEP is not planning to add any supply side resources until 2002, there is no immediate practical effect of a possible overestimate of demand that cannot be rectified in future load forecasts and resource plans. In addition, we believe there is considerable uncertainty regarding AEPCO's future load because of uncertainty about mining loads. To a large extent, AEPCO's member cooperatives can manage that uncertainty as they negotiate special

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of electricity will be negative, indicating that consumption declines as price increases. In most cases gas is a substitute for electricity as indicated by a positive coefficient on the price of natural gas; however, in some cases gas appears to be a complement to electricity as indicated by a negative coefficient on the price of natural gas.

[6] Dummy variables were used to account for marked changes in usage in some sectors. The changes could be due to loss or gain of a large customer or to reclassification of customers. This variable is termed structural dummy in the tables and may be disaggregated to reflect increases or decreases in usage. For forecasting the gross state product (GSP) of mining, we assumed that the future growth rate would be equal to the growth rate of mining GSP over the period 1984 to 1989 (about one percent per year).

[7] Normally, one would expect the signs of the coefficients of CDD and HDD to be positive indicating that hotter summers or colder winters are associated with greater electricity use. However, for those small utilities which have relatively large mining loads (Duncan Valley Electric Cooperative, and Trico industrial customers), we found that the coefficients of CDD or HDD have the "wrong" sign. Based upon monthly electricity consumption from individual mines, we surmise that there can be a seasonal pattern to mining operations (including solution pumping) which may explain the unexpected signs of CDD or HDD.

contracts with mining customers.

We also are concerned about the difficulties of implementing end use forecasting models. End use models, such as Staff's model, SHAPES-PC, can provide additional insight into load growth. However, for such a model to be most useful, detailed data are required. Therefore, we strongly encourage utilities to increase their collection of end use load data, to obtain commercial and industrial energy sales data by Standard Industrial Classification (SIC) category, and to collate that information with data on commercial and industrial customers such as number of employees in each SIC category. The ability of a utility or anyone to forecast demand well for commercial and industrial customers depends on having such disaggregated data. We recommend that the utilities coordinate with Staff their efforts to collect the data described above and that the utilities include the data described above in their annual resource planning data filings.

Table 3

Regression Analyses of APS' MWH Sales by Customer Class

(Dependent variable is MWH sales)

Variable Description	Industrial	Commercial	Irrigation	Residential	Other
Time period	77-91, Annual	81-91, Monthly	77-91, Annual	81-91, Monthly	77-91, Annual
Intercept	2009128.5*	96648.7	-694074.8**	-190914.9***	-121926.9
Electricity price\cust class	-290310.9*	-33370.7***	87366.6*	-6422.3	37092.9**
Gas price\cust class	124040.5	2425.7	49298.7***	-3154.4	
Total employment	3.057***	1.179***			
Arizona mining GSP	479.1				
Heating degree days		75.8***		491.4***	
Cooling degree days		200.6***		364.8***	
Acres utilized for agriculture			1.730***		
Residential customers				1.017***	
Log of time trend			-112639.3***		-33843.2***
Dummy var, July-Sept = 1		18902.3***		86450.7***	
Structural dummy var, incr					52011.2**
Structural dummy var, decr					-41070.1**
R squared	0.81	0.98	0.92	0.95	0.82

* significant at 10% level   ** significant at 5% level   *** significant at 1% level

Table 4

Regression Analyses of MWH Sales, Citizens and Duncan Valley Electric Cooperative

(Dependent variable is MWH sales)

Variable Description	Citizens, Mohave	Citizens, S. Cruz	Duncan Valley
Time Period	81-91, Monthly	81-91, Monthly	77-91, Annual
Intercept	694.2	-4893.1***	729953.2**
Avg. electricity price	-155.0	36.3	-159675.4***
Avg. Gas price	-779.4	-356.1***	278996.6***
Heating degree days	17.7***	3.326***	-189.9**
Cooling degree days	33.3***	6.233***	-552.0***
Residential customers	1.415***	1.664***	
Total employment		0.398***	2603.8***
Arizona mining GSP			713.1***
Log of time trend	-1350.1**		
Dummy var, Summer=1 see note a	1259.3*	-600.1***	
Structural dummy			-101264.1***
R squared	0.95	0.95	0.996

* significant at 10% level   ** significant at 5% level   *** significant at 1% level

a) Summer dummy = 1 for August and September for Citizens Mohave, and = 1 for July - September for Citizens Santa Cruz

Table 5

Regression Analyses of MWH Sales, Graham County, Mohave, and Sulphur Springs Valley Electric Cooperatives, and SRP

(Dependent variable is MWH sales)

Variable Description	Graham County	Mohave	Sulphur Springs	SRP
Time period	77-91, Annual	77-91, Annual	81-91, Monthly	81-91, Monthly
Intercept	-86982.7***	-34158.5	17792.4***	778258.6
Avg. electricity price		-10514.9***	-651.3	
Log electricity price				-526589.7
Lagged avg. electricity price	-3185.9**			
Avg. gas price	-1410.4	17320.5***	-223.6	
Heating degree days			5.760***	696.4***
Cooling degree days	36.0***	17.1***	13.728***	483.9***
Population	5.254***			
Res + Comml Customers			0.502***	2.134***
Total employment		41.3***		
Arizona mining GSP		28.6**		
Dummy, Jul-Sep = 1				110312.8***
R squared	0.91	0.998	0.67	0.96

* significant at 10% level   ** significant at 5% level   *** significant at 1% level

Table 6

Regression Analyses of TEP's MWH Sales by Customer Class

(Dependent variable is MWH sales)

Variable Description	Industrial	Commercial	Irrigation	Residential	Other
Time Period	81-91, Monthly	81-91, Monthly	77-91, Annual	81-91, Monthly	82-91, Annual
Intercept	149605.3***	191670.4***	37163.9***	-4744.9	204726.0*
Electricity price\cust class	-16696.7**		-2769.3***	-7459.8	
Log of electricity price\cust cl		-64861.2***			-72514.8*
Gas price\cust class	-10284.4**		-470.6	-868.5	
Log of gas price					-26449.9
Heating degree days		10.8***		128.0***	
Cooling degree days	39.4***	59.6***		120.1***	
Residential customers				0.772***	
Res + comml customers		0.112***			
Total employment	1.009***				
Precipitation (inches)			-584.9***		
Summer Dummy see note a		-4119.8***		16126.6***	
Structural Dummy			4843.6**		
Log of time trend					52515.6***
R squared	0.94	0.95	0.94	0.94	0.99

* significant at 10% level ** significant at 5% level *** significant at 1% level

a) Summer dummy = 1 in commercial sector equation if month is July or August; = 1 in residential equation if month is July, August, or September.

Table 7

Regression Analyses of Trico's MWH Sales by Customer Class

(Dependent variable is MWH sales)

Variable Description	Industrial	Commercial	Irrigation	Residential	Other
Time period	77-91, Annual	77-91, Annual	77-91, Annual	81-91, Monthly	79-91, Annual
Intercept	804799.7*	-114557.1***	3975.3	-1393.0**	-10.6
Electricity price\cust class	-7319.4	-3991.3***			
Log of electricity price\cust cl			337.5	-264.5	
Gas price\cust class	37796.2	2947.0**			
Log of gas price\cust class			3076.9	152.2	
Heating degree days				5.604***	
Cooling degree days	-403.1***				
Cooling degree days squared				0.006***	
Heating + cooling degree days		7.937**			
Precipitation (inches)			-193.9		
Total employment		18.480***			
Acres utilized for agriculture			0.508*		
Arizona mining GSP	689.2***				
Residential customers				0.620***	
Log of time trend		-21808.3***	-4146.0***		16.0***
Structural Dummy	159615.5***				
R squared	0.97	.99	0.95	0.90	0.80

* significant at 10% level ** significant at 5% level *** significant at 1% level

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ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION

STAFF REPORT ON
RESOURCE PLANNING:
INTRODUCTION AND OVERVIEW

D R A F T

September 1993

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STAFF REPORT ON RESOURCE PLANNING
INTRODUCTION AND OVERVIEW

In 1989, the Arizona Corporation Commission adopted rules for resource planning. These rules require electric utilities with generating facilities to submit resource plans every three years. The utilities subject to the resource planning rules are Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), Arizona Electric Power Cooperative (AEPCO), a generating and transmission cooperative, and Citizens Utilities Company (CUC). In addition, Salt River Project (SRP) has voluntarily participated in the Commission's resource planning process to help the Commission develop a statewide overview of electric utility issues.

The current resource plans were due to be filed with the Commission on December 31, 1992, although some were filed later to allow the utilities to complete their analyses. Copies of the utility filings may be found in Docket Control, in Docket No. U-0000-93-052.

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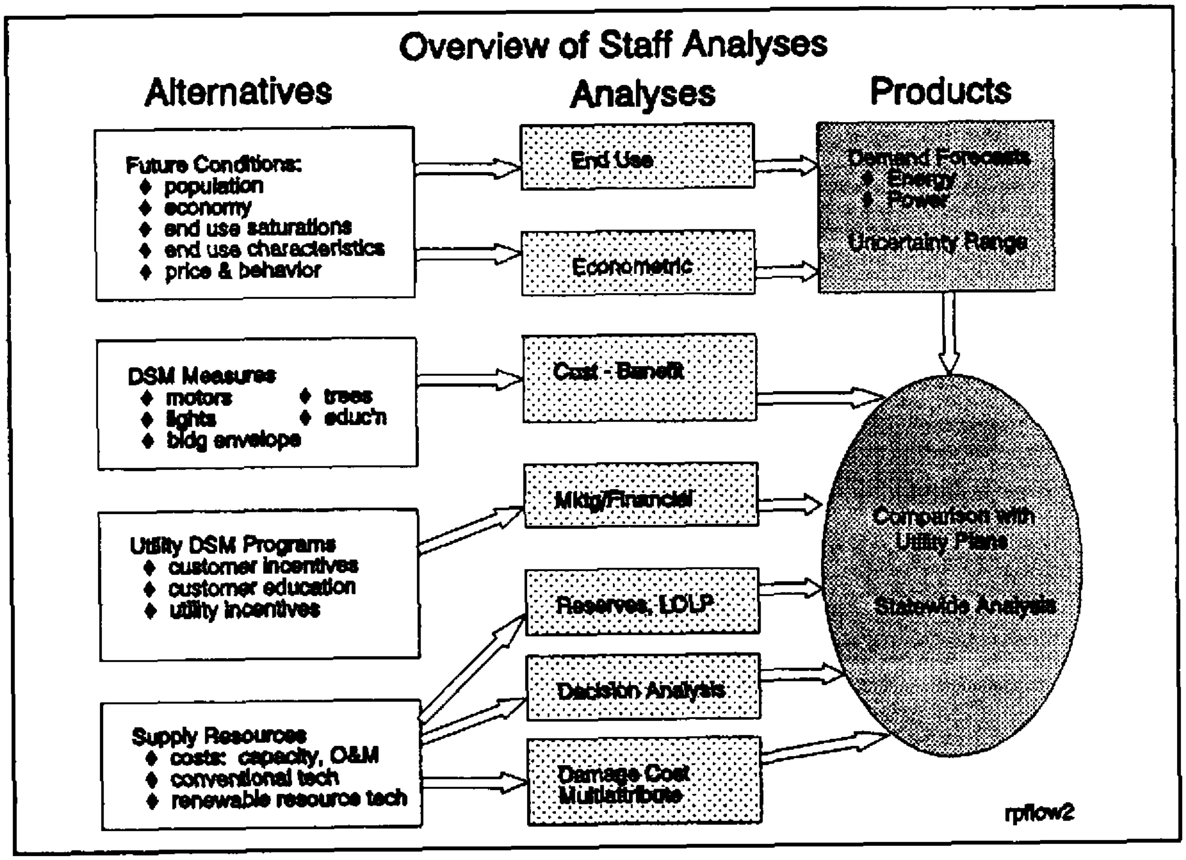
STAFF REPORT ON RESOURCE PLANNING
INTRODUCTION AND OVERVIEW

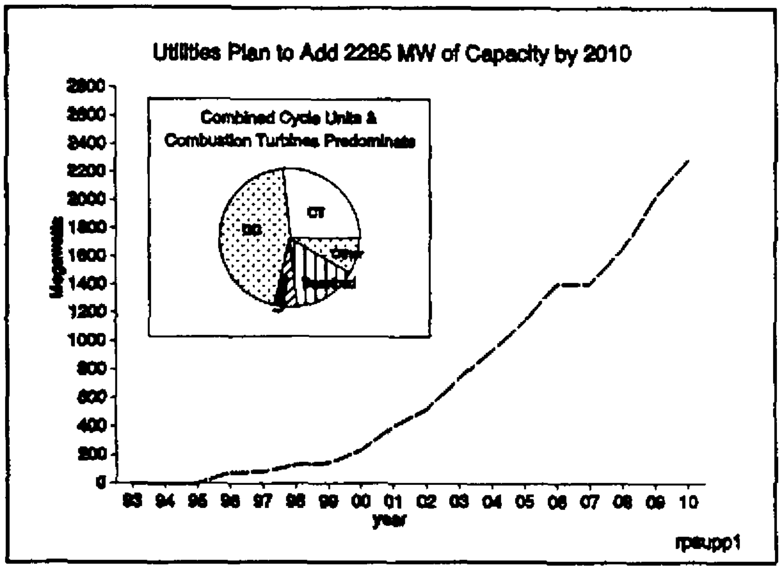
This volume presents a summary of the Staff analysis of the resource plans submitted by Arizona Public Service Company (APS), Arizona Electric Power Cooperative (AEPCO), Tucson Electric Power Company (TEP), and Citizens Utilities Company (Citizens) as required by the Arizona Corporation Commission's resource planning rules (A.A.C. R14-2-701 to R14-2-704). Salt River Project (SRP) also provided the Commission with resource planning data although it is not subject to the Commission's resource planning rules.

The purpose of resource planning is to minimize the total societal costs of meeting the demand for electric energy services such as space heating, space cooling, torque, and lighting. This goal can be achieved by finding the mix of supply and demand side resources that minimizes society's costs.



Our analysis of resource planning is summarized in the above Figure. We examine alternatives affecting resource planning regarding demand factors (population, the economy, appliance trends, etc.) and conduct our own load forecasts, using econometric and end use analyses as an independent check on utility forecasts. We identify alternative demand side management (DSM) measures (such as energy efficient lighting, energy efficient motors, and shade trees), review the costs and benefits of these measures, analyze marketing of DSM measures, and evaluate incentives for utilities to carry out DSM. We also evaluate the capacity costs and operating costs of alternative supply side resources over the life cycle of the resources, including a comparison of renewable resource technologies with conventional fossil-fuel resources. Utility system reliability is also assessed. The analysis of environmental externalities has not yet begun but the Commission Staff is developing rules based on the recommendations of an Externalities Task Force report prepared during 1992.

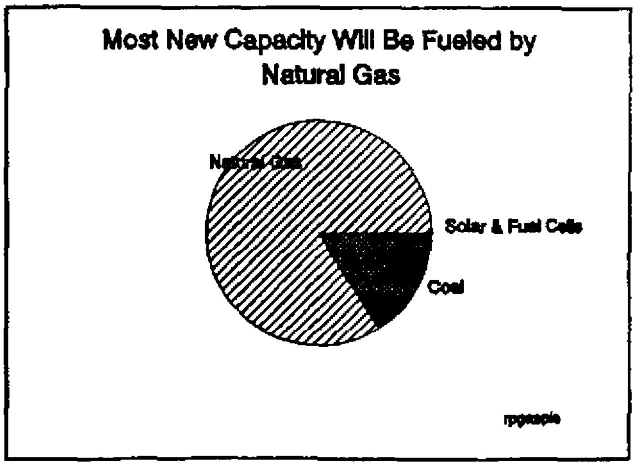
The summary in the following pages highlights major findings of our analyses. For more detail and for a discussion of additional topics, the reader is referred to the remaining volumes in our report. Additional recommendations may also be found in the other volumes.

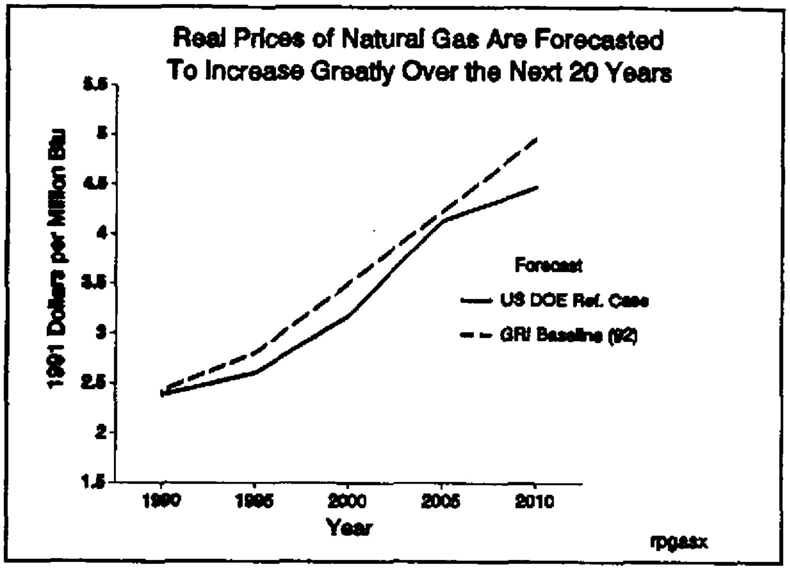


Supply Side

Between 1993 and 2010, Arizona utilities plan to add about 2285 MW of new generating capacity at a cost (present value) of $812 million. The first unit to be added is a 75 MW gas-fired combustion turbine to serve Citizens starting in 1996.

Most of the planned capacity to be added between 1993 and 2010 is gas-fired. Combined cycle units comprise nearly half of the planned additions, combustion turbines account for about 25 percent of the new capacity, baseload units comprise 15 percent of the new capacity and the remainder consists of increasing the capacity of existing plants (uprating) and the use of other technologies, including 10 MW of photovoltaics and 2 MW of fuel cell production.





<u>Renewables versus Gas-Fired Resources</u>. According to U.S. Department of Energy and Gas Research Institute forecasts, the real price of natural gas is likely to double over the next 20 years. Unfortunately, it appears that the utilities do not plan to hedge their bets on future power plant technologies by diversifying their resource choices. We conclude that the potential for large real (inflation adjusted) price increases for natural gas is sufficient to warrant further consideration of renewable resources, especially solar thermal resources.

Common forms of renewable energy resources include: photovoltaics; solar thermal resources such as parabolic troughs, parabolic dishes, and central receivers; windpower; biomass consisting of wood, wood waste, agricultural waste, municipal solid waste, and landfill and digester gas; geothermal resources, including hydrothermal resources and hot dry rock; and hydropower.

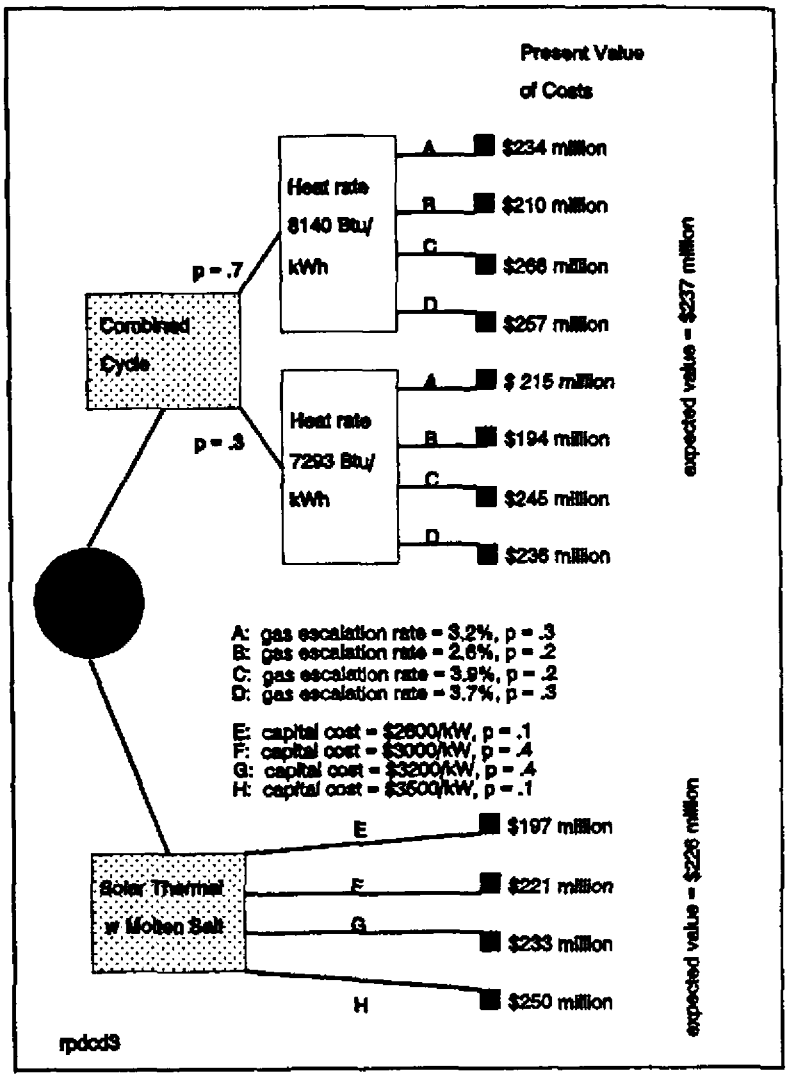
To compare the possible costs of renewable resources with conventional resources, it is necessary to undertake a systematic review of the possible events which affect costs and the chances of those events occurring. Decision analysis offers such a systematic review. We conducted an *illustrative* decision analysis of the life cycle costs of a combined cycle unit and a solar thermal central receiver to come on line in 2003. The illustration takes into account two possible levels of performance of combined cycle plants (represented by heat rates), four levels of natural gas costs, and four levels of capital costs of a solar central receiver plant. The analysis is summarized on the next page as a decision tree. Each of the performance and cost levels is assigned a probability of occurring (as indicated by the value of p) and the average or expected values of the costs of the combined cycle unit and solar central receiver are calculated. In the illustration, the expected value of the costs of the combined cycle unit is higher than the expected values of the costs of the solar central receiver ($237 million versus $226 million over the life assumed 30 year life of the plants). Although the decision analysis is illustrative, it suggests that solar thermal power could be cost competitive with natural gas fired plants or even cheaper than natural gas fired plants.

Because of the utilities' dependence on gas fired capacity and the potential cost savings from renewables, we recommend that the Commission:

- Allow cost recovery for prudent investments in renewable generation demonstration projects.

- Approve set asides for renewable resources of 40 MW each for AEPCO and Citizens and 160 MW each for TEP and APS to be added by 2009; this level of investment in renewables is large enough to contribute to the utility's capacity and is within the time frame of planned capacity additions.

- Allow utilities to recover the costs of set aside renewable resources (within limits on the cost per kW).



Illustrative Decision Tree

- Require utilities to include in their next resource plans (to be filed in 1995) explicit discussion of their research and development activities regarding renewables.

We also recommend that a study group composed of Staff and other parties to the resources planning docket be created to:

- develop a better understanding of how to evaluate the benefits and risks of gas fired plants and renewables,

- develop a risk benefit analysis of a generic combined cycle unit, a generic solar unit and possibly generic wind turbines to improve our understanding of how to conduct such an analysis, and

- develop suggestions on how utilities should analyze the risks and benefits of renewables.

Payments for Purchases from Qualified Cogenerators and Small Power Producers. Under the Public Utility Regulatory Policies Act of 1978, utilities are obligated to purchase energy and power from qualifying cogenerators and small power producers at rates up to the utility's avoided costs. Utilities have not offered capacity payments for purchases of power from qualifying facilities, however. In its previous resource planning order, the Commission ordered the utilities to file proposed capacity and energy rates for purchases from qualifying facilities in their 1992 resource planning filings. Only APS filed capacity rates.

We developed capacity payments for qualifying facilities offering power starting in 1994 based upon deferral of the next power plant planned by each utility assuming contracts of various lengths and considering whether the qualifying facility wants payments to begin in 1994 (up-front payments) or is willing to wait for capacity payments until the year the utility would otherwise need to add capacity. The present value of capacity payments should equal the present value of the deferral of capacity costs. Table A summarizes the capacity payment streams. We recommend that utilities submit values for capacity payments for Staff review and approval using the principles underlying the values in Table A within six months of the date of the decision in this resource planning docket. The values in Table A (or Staff updates of these values) should be used if the utility does not submit the capacity values.

Table A

ESTIMATE OF THE VALUE OF CAPACITY
OF A CONTRACT WITH A QF OR OTHER SUPPLIER

Contract Starting in 1994

		APS	TEP	AEPCO	CUC
Year Capacity Otherwise Needed		2000	2002	2001	1996
Type of Capacity Deferred		CT	CT	CC	CT
Up-Front Payments?	Duration of Contract (years)	Payments for Capacity $/kW/Year			
no	10	$56.15	$58.29	$90.40	$51.82
	15	$60.25	$62.84	$97.22	$55.09
	20	$63.98	$67.05	$103.48	$57.98
yes	10	$15.95	$7.44	$18.25	$36.66
	15	$25.04	$18.09	$33.88	$42.11
	20	$30.31	$24.05	$42.76	$45.68

Assumptions:

- Assumes small QFs (e.g. projects whose total capacity in 1993 for any utility is less than the capacity of the next planned utility unit).
- If up-front payments are required, equal payments will be made each year of the contract starting in 1994; the present value of the stream of payments is the present value of capacity deferral savings.
- If no up-front payments are required, equal payments will be made each year starting in the year the utility would otherwise need capacity; the present value of the stream of payments is the present value of capacity deferral savings.
- CTs assumed to cost $536 per kW in 1994 dollars if installed in 1994; CCs assumed to cost $771 per kW in 1994 dollars if installed in 1994; life of units = 30 years.
- Avoided fixed O&M costs due to deferral assumed to be $3.21/kW for CTs and $10.71/kW for CCs (1994 dollars).
- Inflation assumed to be 3.5 percent per year; real interest rate assumed to be 7 percent.

Demand Forecasts

The utilities' long range forecasts of retail MW demand show that growth rates are expected to average between about 2 and 3 percent per year between 1993 and 2002, except for Citizens, which expects an average annual growth rate of 3.9 percent (Table B). Growth rates in energy sales (megawatt hours) are forecast by the utilities to be between 2 and 3 percent per year on average for the period 1993 to 2002, except for Citizens' energy sales which are forecast to grow by an average of 4.3 percent per year (Table C). Note that AEPCO's forecasts are affected by the expected loss of a large mining load in 1998. *Demand is defined to be the demand for electric energy services which includes demand met by electricity production and by demand side management.*

Table B

Utility Forecasts of Growth Rates of Retail Demand (MW)

Utility	Time Period	Average Annual Compound Growth Rate (%)
AEPCO*	1993 - 2002	2.0
APS	1993 - 2001	3.1
Citizens	1993 - 2002	3.9
SRP	1993 - 2002	2.6
TEP	1993 - 2002	2.9

* Pertains to retail sales by all Class A members.

We conducted an analyses of demand for the period 1993 to 2002 to provide an independent assessment of future demand using utility filings for historical consumption data and other sources such as the Department of Economic Security for historical population and employment data and for forecasts of factors which affect the demand for electricity. Our principal demand forecasting approach was econometric models of megawatt hour sales.

Table C

Forecasts of Growth Rates of Retail Energy Sales

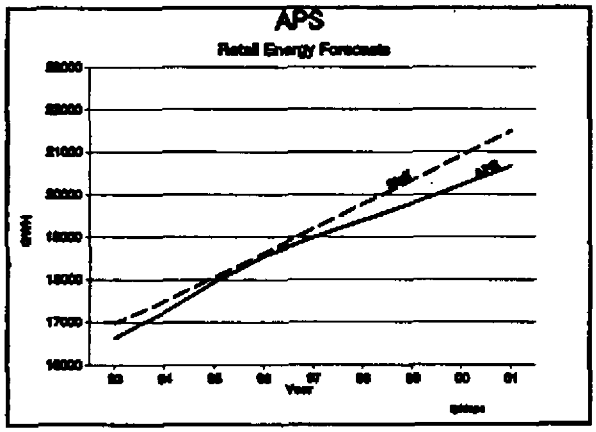
Utility	Time Period	Average Annual Compound Growth Rate (%)	
		Utility Forecasts	Staff Forecasts
AEPCO*	1993 - 2002	2.1	2.2
APS	1993 - 2001	2.8	3.0
Citizens	1993 - 2002	4.3	4.6
SRP	1993 - 2002	2.7	2.4
TEP	1993 - 2002	2.9	2.2

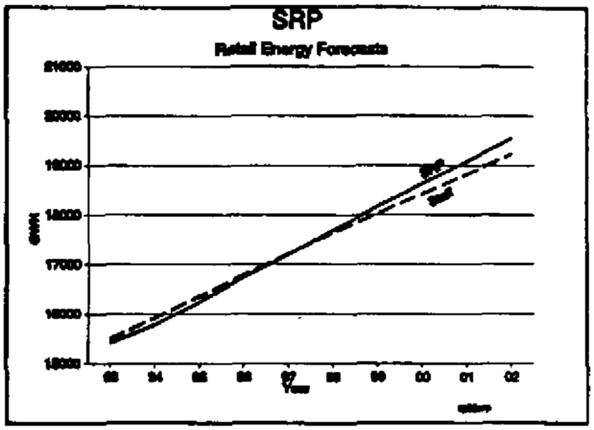
* AEPCO's forecast pertains to retail sales by all Class A members; Staff's forecast excludes Anza.

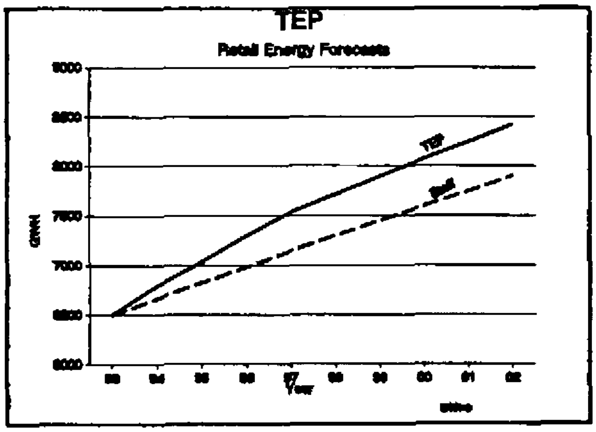
Our econometric forecasts are compared with the utility forecasts in the figures on the following page. As stated above, demand is defined to be the demand for electric energy services which includes demand met by electricity production and by demand side management. We conclude that APS's, SRP's, and Citizens' forecasts are consistent with ours. TEP's forecast, however, shows a considerably higher growth rate than ours in the first five years, which appears to be due to TEP's relatively high industrial sales forecast for that period. This difference in forecasts may indicate that TEP is facing greater uncertainty about future demand than some of the other utilities. We invite TEP to help clarify the gap between the forecasts for industrial sales.

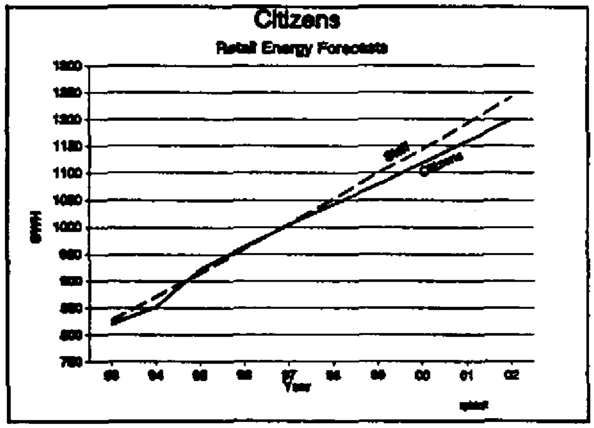
AEPCO's forecast is also consistent with ours,[1] although alternative forecasts should be considered to reflect uncertainty about future mining load. AEPCO's forecast incorporates a new mining customer in 1997 and the loss of a mining customer in 1998. The figure labeled "AEPCO: Staff Retail Energy Forecast Scenarios" illustrates three alternative forecasts. Forecast A assumes that existing mining customers are retained and no new mining customers are added. Forecast B assumes loss of an existing mining customer and no new mine is added. Forecast C assumes that existing mining customers are retained and that one new mine is added.

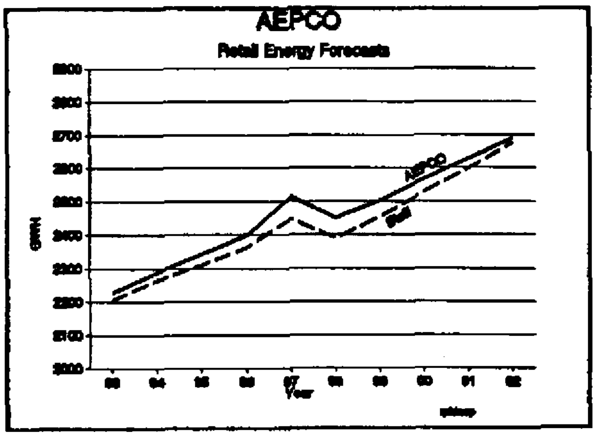
[1] The gap between the Staff and AEPCO forecasts is probably largely due to Staff's exclusion of sales by Anza; AEPCO's forecast includes sales by Anza.

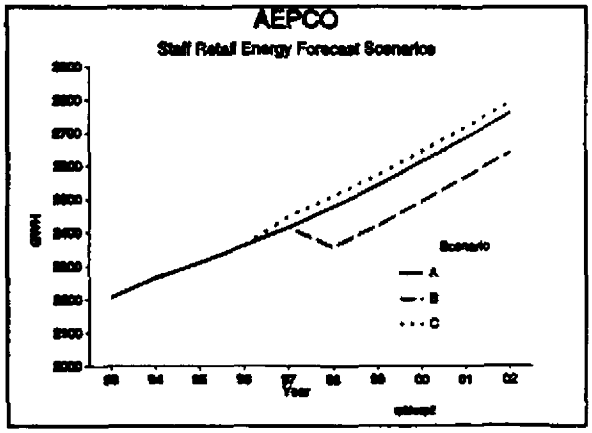

APS
Retail Energy Forecasts
Year


SRP
Retail Energy Forecasts
Year


TEP
Retail Energy Forecasts
Year


Citizens
Retail Energy Forecasts
Year


AEPCO
Retail Energy Forecasts
Year


AEPCO
Staff Retail Energy Forecast Scenarios
Year

Our expected growth rate for each utility's sales is included in Table C. We expect sales growth to average between 2.2 percent to 3 percent per year, excluding Citizens. Citizens' growth rate is considerably higher than the other utilities due to continued high customer growth in the Mohave area. Our forecasted growth rates are within 0.3 percentage points of the utilities' energy forecasts with the exception of TEP. TEP's forecasted growth in the first 5 years is considerably higher than Staff's, but in the remaining years the TEP and Staff growth rates are about the same, as seen in the slopes of the graphs.

Demand Side Management

Current Programs. The major DSM programs currently underway in Arizona are:

- Commercial sector lighting programs in which inefficient lighting is replaced by more efficient lamps and ballasts, in which adequate lighting levels are maintained through delamping and installation of reflectors, and in which lighting is controlled by occupancy sensors and dimmers.
- Education programs aimed primarily at school children.
- New home programs aimed at meeting energy efficient mortgage performance standards for the entire house allowing builders to substitute among efficiency measures to meet the standard; some programs have focused only on heat pump efficiency upgrades, however.
- Residential retrofit programs, currently focused on upgrading the efficiency of heat pumps.
- Residential audits in which the consumer fills out a form and receives an audit by mail; on-site audits may be conducted if requested by the consumer.
- Tree planting to create shade on sunstruck sides of buildings and thereby reduce space cooling needs.
- Energy efficient motors.

The utilities have not completed monitoring of savings from their pre-approved DSM programs. Savings based on engineering estimates for the largest programs in 1992 are presented in Table D. Engineering estimates may be grossly in error because customer behavior may alter the expected performance of the measure and because on-site conditions may vary from those assumed in making the engineering estimate. Thus, the savings estimates are to be considered as preliminary and monitoring results may be different.

Table D

Engineering Estimates of Savings From Major DSM Programs

(as of December 31, 1992)

Type of Program	Measure	APS	TEP	AEPCO
Commercial Sector Lighting	Number of Customers	52	200	
	kW Savings	1373[a]	3641[d]	
	MWH Savings per yr	1488[a,b]	17,621[d]	
Energy Efficient New Homes	Number of Homes	1494		
	kW Savings	1061[c]		
	MWH Savings per yr	2816[b,c]		
Residential Retrofit Heat Pump Upgrades	Number of Customers			143
	kW Savings			60 - 72[e]
	MWH Savings per yr			159[e]

Sources:

Arizona Public Service Company, Annual Report on the Energy Efficiency and Solar Energy Fund, March 31, 1993, as revised June 7, 1993, July 27, 1993, and September 14, 1993.

Tucson Electric Power Company, Annual DSM Progress Report, pages 111-139 in TEP's April 1, 1993 historical data filing in Docket No. U-0000-93-052.

Arizona Electric Power Cooperative, Semi-Annual Status Report for Demand-Side Management Programs for the Period Ending December 31, 1992, and responses to questions dated February 3, 1993.

a Assumes avoidance of 5% losses.

b Partial year data only.

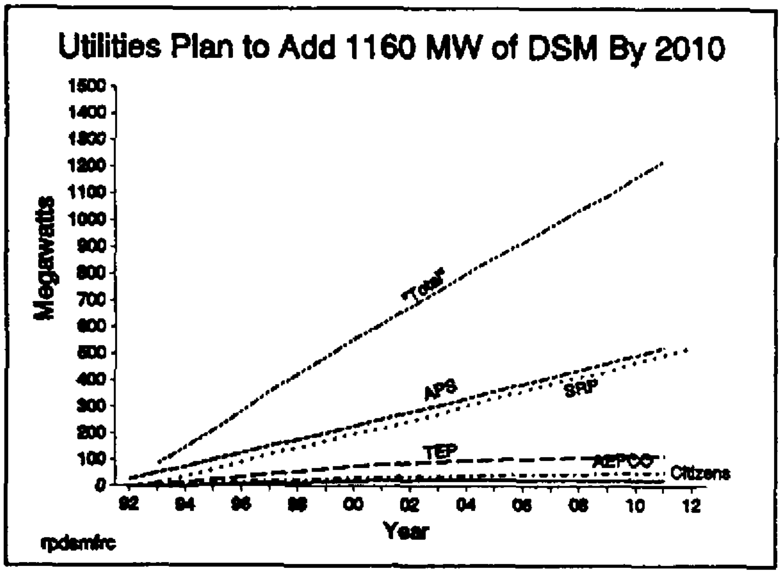
c Staff's preliminary estimates of savings are lower: 777 kW and 1134 MWH (partial year). Staff assumed baseline is more energy efficient that APS assumes.

d Staff estimates of savings assuming 90 percent probability lights are on at any hour, additional 10 percent savings attributable to reduced space cooling needs, and 8.57 percent line losses avoided.

e Staff estimates.

Utility progress on monitoring and program evaluation is hard to judge since monitoring efforts are still underway. However, there seems to be varied attention paid to the importance of assessing how well a program is working in the field. We recommend that utilities give the highest priority to monitoring and evaluation, including evaluation of kW and kWh savings and process evaluation, in their DSM efforts.

Projections of DSM. Utility projections of DSM power savings are about 1160 MW between 1992 and 2010. The graph reflects additions to DSM already in place. Overall, through 2010, additions of DSM are about one quarter of the projected growth in demand (where demand consists of retail demand plus energy services met through DSM).



Evaluation of DSM. We evaluated several DSM measures and found the following:

1) High efficiency motors are generally cost effective relative to motors of standard efficiency.

2) Energy efficient lamps and reflectors are generally cost effective in commercial buildings; electronic ballasts may or may not be cost effective relative to energy efficient magnetic ballasts, however.

3) The cost-effectiveness of thermal (cool) storage is difficult to establish given the data available; however, some thermal storage projects do not work as well as expected.

4) Residential retrofit program success depends on targeting of houses. Savings from residential retrofit measures are critically dependent on the type of cooling used in the house (air conditioning or heat pumps versus dual cooling using an evaporative cooler and an air conditioner or heat pump), house size and window characteristics of the house. In particular, on houses with only an air conditioner or heat pump, savings are much larger if the house has single pane windows. For houses with dual cooling, savings are larger for larger houses, for houses with a small proportion of the west facing wall in windows, and houses with a greater fraction of the walls (except

the west facing wall) in windows. The impacts of structural features probably derive from behavior of the occupants, reflecting differences in consumers' taking back some of the savings due to the conservation measures in the form of cooler indoor temperatures. Generally speaking, energy savings tend to be the largest in houses that were the least energy efficient prior to the conservation treatment.

5) On carefully targeted houses, added attic insulation (in houses with low levels of insulation) and shade trees are cost effective retrofit treatments.

6) Air conditioners and heat pumps with SEERs (seasonal energy efficiency ratios) higher than about 10 are generally not cost effective given the current high prices of incremental improvements of SEERs above about 10 (the minimum efficiency that can be manufactured).

7) DSM programs aimed at low income households should be carefully targeted so that society's benefits from reduced energy and power usage are greater than the incremental costs of undertaking such programs and so that low income customers see a significant savings on their electric bills. Thus, the kinds of cost effective residential retrofit measures cited above (insulation and shade trees) could be offered on targeted houses in low income areas.

8) Utilities should consider a design team approach to new commercial buildings to encourage the construction of energy efficient new buildings.

Incentives to Utilities to Engage in DSM. To help remove financial disincentives to utilities for engaging in DSM, it may be necessary to compensate the utility so that it is indifferent between traditional supply side resources and cost effective DSM. Relative to traditional regulation, a DSM program will have to ensure timely recovery of program costs, and a return equivalent to what the utility would have received from regulatory lag (increased sales between rate cases minus variable costs, i.e. net revenues) and from ratebasing future generating, transmission, and distribution capacity that will be deferred or avoided as a result of DSM.

Financial barriers to DSM have led the Commission to develop mechanisms for program cost recovery, recovery of lost net revenues, and recovery of a profit or reward to make the utility indifferent between traditional supply side resources and DSM. Table E summarizes the status of such mechanisms for pre-approved projects.[2]

[2] APS is the only utility currently authorized to receive a reward or profit for successful DSM. For pre-approved DSM measures (which are likely to be cost-effective), APS receives a reward whose present value is approximately equal to the present value of the deferred return on new capacity which was deferred as a result

Table E

Monetary Incentives for Utilities to Engage in DSM
(applies to pre-approved DSM projects)

Component	APS	TEP	AEPCO	Trico[4]	SSVEC[4]	Citizens	Navopache
Recovery of Program Costs[1]	yes	yes	yes	yes	yes	yes	yes
Recovery of Lost Net Revenues	yes	no[2]	no	no	no	no	yes
Reward, Profit, or Incentive	yes	no	no	no	no	no	no
Recovery Mechanism	surcharge	included in base rates[2]	via fuel & purch'd power adjustor[3]	via purch'd power adjustor	via purch'd power adjustor	deferral account with interest	surcharge
Decision No.	57649	57586 Exh A Para 17	58405	57915	58358	58360	57978

1) program costs pertain to administrative costs, any equipment costs, the value of rebates or other financial incentives offered to consumers, and monitoring and evaluation costs.

2) In the pending rate case (Docket Nos. U-1933-93-006 and U-1933-93-066), Staff has recommended recovery of lost net revenues when savings can be demonstrated and has recommended that cost recovery be included in base rates.

3) Costs of pre-approved AEPCO programs are paid for by AEPCO and passed along to all AEPCO Class A member cooperatives through AEPCO's purchased power and fuel adjustor.

4) Pertains to pre-approved programs that are not part of AEPCO's pre-approved programs.

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of the DSM project. The reward is paid out over the lifetime of the DSM project on a dollar per kW deferred basis. The payment per kW deferred declines over time similar to the declining interest component on a mortgage.

Development of incentives for utilities is still evolving and we believe that further experience with various approaches is needed before the most appropriate incentives can be determined. For example, the magnitude of any incentive, the duration over which it is paid, whether a minimum level of savings should be achieved before an incentive is paid, and disagreements about kW and kWh savings between the utility and the Commission could all influence the effectiveness of incentives.

<u>DSM and the Energy Policy Act of 1992</u>. Section 111 of the Energy Policy Act of 1992 pertains to integrated resource planning and demand side management. In particular, several standards are added to the Public Utility Regulatory Policies Act of 1978 ("PURPA," 16 USC 2621):

- Electric utilities must engage in integrated resource planning.
- DSM should be at least as profitable as supply side investments, taking into account lost net revenues resulting from DSM.
- DSM programs must be monitored and evaluated.

We believe the Commission has considered these standards through its resource planning rules (A.A.C. R14-701 et seq.) which have been in effect since 1989 and through rate case decisions cited in Table E.

Administrative Recommendations

After reviewing utility resource plans for both 1989 and 1992, we believe several generic improvements can be made. In particular, we propose the following features for future plans filed with the Commission:

- Each plan should have a comprehensive, self-explanatory load and resources table summarizing the utility's plan.
- Each plan should have an easy-to-read, brief executive summary that will inform the public about the utility's plan; the load and resources table should be included in the executive summary. The executive summary can be provided to people requesting copies of the utility plans instead of copying voluminous technical information that is of little value to individuals interested in a non-technical report.
- Voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper.

- The plan should be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc. Disjointed discussions of topics that do not lead to conclusions do not enhance the reader's understanding of the utility's plans.

- Each plan should be indexed to indicate where the filing requirements can be found (see APS' plans for an example).

- Terms should be defined as they are used by the utility; for example, different utilities use the term "forced outage rate" differently and it is not always clear whether demand includes or excludes sales for resale. To avoid confusion, it is better to be clear.

- Utilities should strive for consistency in data and assumptions throughout their plans.