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February 28, 2003

2003-69-E

VIA HAND-DELIVERY

S. C. PUBLIC SERVICE COMMISSION
RECEIVED
UTILITIES DEPARTMENT

The Honorable Gary E. Walsh
Executive Director
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: South Carolina Electric and Gas Company's 2003 Integrated Resource Plan

Dear Mr. Walsh:

In accordance with Order No. 98-502 issued in Docket No. 87-223-E and dated July 2, 1998, enclosed are ten (10) copies of South Carolina Electric & Gas Company's 2003 Integrated Resource Plan. This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C Code § 58-33-430.

I would appreciate your acknowledging receipt of these documents by stamping the extra copy enclosed and returning it with our courier. If you should have any questions or need additional information, please do not hesitate to contact me.

Sincerely,

Craig Collins

B. Craig Collins

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Enclosures

2003

Integrated

Resource

Plan

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Introduction

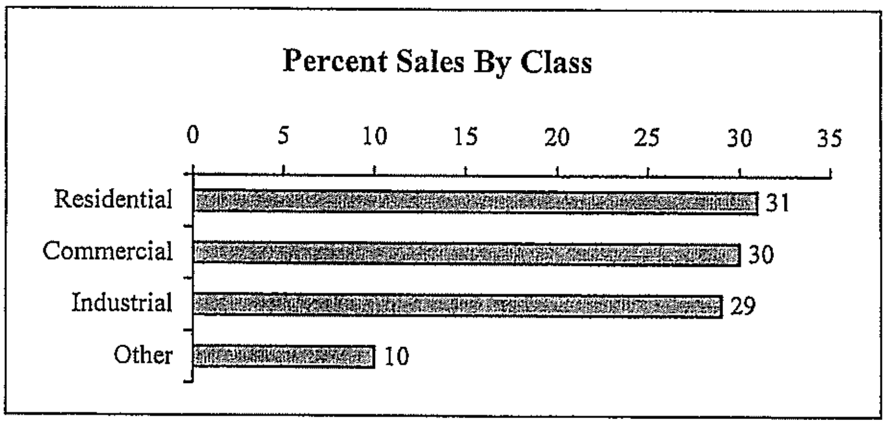
This document presents South Carolina Electric And Gas Company's (SCE&G) Integrated Resource Plan (IRP) for meeting the energy needs of its customers over the next fifteen years, 2003 through 2017. The Company's objective is to provide reliable and economically priced energy to its customers. This document updates the Company's last IRP and supplements the detailed information presented by the Company in the siting of the Jasper County Generating Facility under Commission Docket No. 2001-420-E, Order No. 2002-19 dated January 11, 2002.

The Load Forecast

Total energy sales on the SCE&G system are expected to grow at 2.2% per year over the next 15 years. The summer peak demand and winter peak demand will increase at 2.1% and 2.4% per year respectively over this forecast horizon. The table below contains the projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2003	4,438	4,092	22,455
2004	4,531	4,183	22,908
2005	4,633	4,286	23,413
2006	4,739	4,393	23,940
2007	4,848	4,503	24,496
2008	4,967	4,625	25,091
2009	5,077	4,741	25,666
2010	5,190	4,861	26,268
2011	5,308	4,985	26,872
2012	5,422	5,106	27,471
2013	5,537	5,228	28,084
2014	5,641	5,342	28,639
2015	5,745	5,456	29,205
2016	5,854	5,574	29,799
2017	5,948	5,680	30,314

The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our seven classes of customers. The three primary customer classes: residential, commercial, and industrial, comprise about 90% of our sales. The bar chart shows the relative contribution to territorial sales of each class. The other classes are street lighting, other public authorities, municipalities and cooperatives. A detailed description of the short range forecasting process and statistical models is contained in Appendix A of this report. Appendix B contains similar information for the long range methodology. Sales projections to each group are based on statistical and econometric models derived from historical relationships.



The forecast of summer peak demand is developed using a load factor methodology. Load factors for each class of customer are associated with the corresponding forecasted energy to project a contribution to summer peak. The winter peak demand is projected through its correlation with annual energy sales and winter degree day departures from normal. By industry convention, the winter period is assumed to follow the summer period.

New Peak Demand Set In Winter

On January 24, 2003 SCE&G experienced a new territorial peak demand on its system of 4,513 MWs at hour ending 8:00 a.m. This was 50MWs higher than the peak demand set the previous summer. The summer peak demand was 4,463 MWs and was set on July 30, 2002 at hour ending 5:00 p.m. Although the current territorial peak occurred in winter, the Company expects to remain a summer peaking utility during the forecast horizon, at least under normal weather conditions. The table below shows the impact of colder than normal weather on our latest peak. By normal we mean the average weather occurring on the territorial peak day of each winter for the past 25 years.

Weather Impact for January 24, 2003					
Daily Temperature	Actual	Normal	Deviation	Model Coefficient	MW Impact
Maximum	37.0	42.9	-5.9	-10.3	60.77
Minimum	15.0	17.7	-2.7	-47.9	129.33
					190.1

The Mw impact on the winter peak day was about 190 MWs. Thus the weather normalized peak demand is 4,323 MWs (4,513 - 190).

A similar analysis is done for the summer period. The following table shows the result.

Weather Impact for July 30, 2002					
Daily Degree Days	Actual	Normal	Deviation	Model Coefficient	MW Impact
Cooling	23.0	21.9	1.1	43.2	47.52

The Mw impact on the summer peak day is about 48 MWs. Thus the weather normalized peak demand is 4,415 MWs (4,463 - 48).

From this analysis it can be seen that on a weather normalized basis our summer peak demand is higher than the winter peak demand.

Demand-Side Management

There are two primary demand-side management programs at SCE&G: the standby generator program and the interruptible service program. The Company relies on these programs to help maintain the reliability of its electrical system. There are 216 megawatts of capacity made available to the system through these programs. The table below shows the peak demand on the system with and without these programs. The firm peak demand is the load level that results when the DSM is used to lower the system peak demand.

	System Peak (MW)	DSM Impact (MW)	Firm Peak (MW)
2003	4,654	216	4,438
2004	4,747	216	4,531
2005	4,849	216	4,633
2006	4,955	216	4,739
2007	5,064	216	4,848
2008	5,183	216	4,967
2009	5,293	216	5,077
2010	5,406	216	5,190
2011	5,524	216	5,308
2012	5,638	216	5,422
2013	5,753	216	5,537
2014	5,857	216	5,641
2015	5,961	216	5,745
2016	6,070	216	5,854
2017	6,164	216	5,948

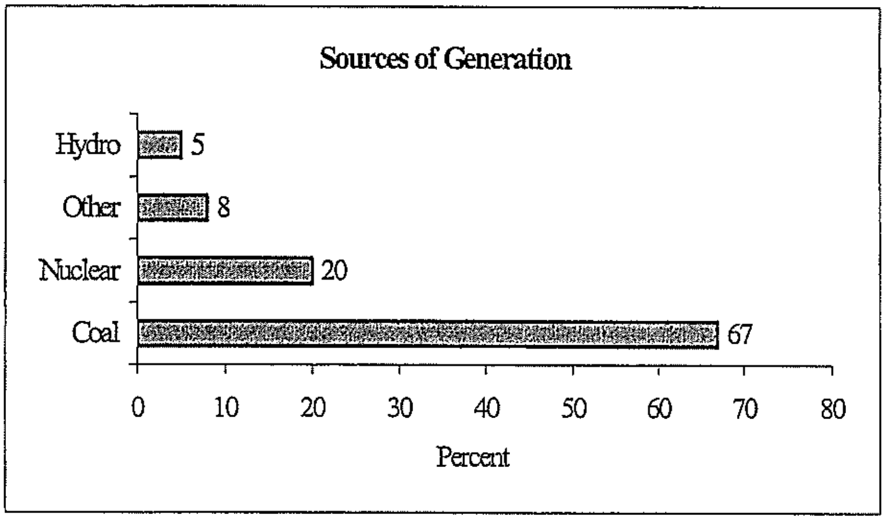
The programs mentioned above are directed toward load management. The Company is also committed to energy conservation and the wise use of electricity. We offer conservation rates and time of use rates to allow customers the opportunity to save on their electric bill. Additionally all our rates are designed to provide correct price signals and thereby encourage our customers to use energy wisely especially during the peak season.

Existing Supply Capacity

The following table shows the generating capacity that is available to SCE&G.

2002 Existing Capacity		
	In-Service Date	Summer (MW)
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	94
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	396
Wateree – Eastover, SC	1970	700
Williams – Goose Creek, SC	1973	615
D-Area – USDOE Savannah River Site	1995	35
Cope - Cope, SC	1996	410
Cogen South – Charleston, SC	1999	90
Total Coal-Fired Steam Capacity		2,590
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
Burton, SC	1961	27
Faber Place – Charleston, SC	1961	8
Hardeeville, SC	1968	12
Urquhart – Beech Island, SC	1969	40
Coit – Columbia, SC	1969	32
Parr, SC	1970	69
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	86
Urquhart No. 4 – Beech Island, SC	1999	51
Urquhart Combined Cycle – Beech Island, SC	2002	476
Total I. C. Turbines Capacity		841
Hydro:		
Neal Shoals – Carlisle, SC	1905	5
Parr Shoals – Parr, SC	1914	15
Stevens Creek - Near Martinez, GA	1914	12
Columbia Canal - Columbia, SC	1927	9
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	544
Total Hydro Capacity		791
Other: Long-Term Purchases		25
SEPA		22
Grand Total:		4,913

The bar chart shows the projected 2003 generation by fuel source. SCE&G generates the overwhelming amount of its energy from coal and nuclear fuel. This will not change during the forecast horizon but more generation will come from natural gas especially after the Jasper plant comes on-line in 2004.



Supply Reserve Margin

The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. The appropriate level of reserve capacity for SCE&G is in the range of 12 to 18 percent of its firm peak demand. This range of reserves will allow SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply risk and demand risk. These are discussed below.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR has set the region's reserve needs at 150% of the largest unit in the region. SCE&G's prorata share of this capacity is 195 megawatts.

Supply reserves are needed to balance the risk that some capacity may be forced out on any particular day because of mechanical failures, wet coal problems or environmental limitations. The amount of capacity forced-out or down-rated will vary from day to day. SCE&G's reserve margin range is designed to cover most of these days as well as the outage of any of our generating units except the two largest: Summer Station and Williams

Station. The last component of reserve margin is the demand reserve. This is needed to cover risks related to unexpected increases in load above our peak demand forecast. This can be the result of a hotter than normal summer or forecast error.

By maintaining a reserve margin in the 12% – 18% range, the Company addresses the uncertainties related to load and to the availability of generation on its system as well as to meet its VACAR obligation. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

Projected Loads And Resources

The table on the following page shows SCE&G's projected loads and resources for the next 15 years. Known capacity additions include: the uprate at Fairfield Pumped Storage in 2003 and 2004 and the addition of the Jasper Combined Cycle Plant in 2004. The Company's total firm load obligation includes a firm contract sale for the years 2004 through 2012. The Company believes that this supply plan will be as benign to the environment as possible because of its reliance on efficient, gas fired generation and that it will keep the cost of energy service competitive since the generating units being added are competitive with other units being added in the market.

SCE&G Forecast of Summer Loads and Resources – 2003 Budget

YEAR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Load Forecast															
1 Gross Territorial Peak	4654	4747	4849	4955	5064	5183	5293	5406	5524	5638	5753	5857	5961	6070	6164
2 Less: DSM	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216
3 Net Territorial Peak	4438	4531	4633	4739	4848	4967	5077	5190	5308	5422	5537	5641	5745	5854	5948
4 Firm Contract Sales		350	350	250	250	250	250	250	250	250					
5 Total Firm Obligation	4438	4881	4983	4989	5098	5217	5327	5440	5558	5672	5537	5641	5745	5854	5948
System Capacity															
6 Existing	4913	4929	5820	5820	5820	5820	5820	5970	6120	6270	6420	6420	6420	6420	6570
Additions															
7 Fairfield P.S.	16	16													
8 Jasper Combined Cycle		875													
9 Undecided							150	150	150	150				150	150
10 Total System Capacity	4929	5820	5820	5820	5820	5820	5970	6120	6270	6420	6420	6420	6420	6570	6720
11 Firm Annual Purchase	50					50							50		
12 Total Production Capability	4979	5820	5820	5820	5820	5870	5970	6120	6270	6420	6420	6420	6470	6570	6720
Reserves With DSM Impact															
13 Margin	541	939	837	831	722	653	643	680	712	748	883	779	725	716	772
14 % Reserve Margin	12.2%	19.2%	16.8%	16.7%	14.2%	12.5%	12.1%	12.5%	12.8%	13.2%	15.9%	13.8%	12.6%	12.2%	13.0%
15 % Capacity Margin	10.9%	16.1%	14.4%	14.3%	12.4%	11.1%	10.8%	11.1%	11.4%	11.7%	13.8%	12.1%	11.2%	10.9%	11.5%
Reserves Without DSM Impact															
16 Margin	325	723	621	615	506	437	427	464	496	532	667	563	509	500	556
17 % Reserve Margin	7.0%	14.2%	11.9%	11.8%	9.5%	8.0%	7.7%	8.2%	8.6%	9.0%	11.6%	9.6%	8.5%	8.2%	9.0%
18 % Capacity Margin	6.5%	12.4%	10.7%	10.6%	8.7%	7.4%	7.2%	7.6%	7.9%	8.3%	10.4%	8.8%	7.9%	7.6%	8.3%

Appendix A

Short Range Methodology

This section presents the development of the short range electric sales forecasts for the Company. Two years of monthly forecasts for electric customers, average usage, and total usage were developed according to company class and rate structures, with industrial customers further classified into SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes) and by whether or not they use electric space heating. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Monthly heating and cooling degree data for Columbia and Charleston are also available historically, and may be forecast using averages based on NOAA normals[1]. Industrial production indices are also available by SIC on a quarterly basis, and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for marketing programs, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS[2] was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

Two variables were used extensively in developing weather sensitive average use models: heating degree days (HDD) and cooling degree days (CDD). The values for HDD and CDD are the average of the values for Charleston and Columbia. The base for HDD was 60° and for CDD was 75°. In order to account for cycle billing, the degree day values for each day were weighted by the number of billing cycles which included that day for the current month's billing. The daily weighted degree day values were summed to obtain monthly degree day values. Billing sales for a calendar month may actually reflect consumption that occurred in the previous month based on weather conditions in that period and also consumption occurring in the current month. Therefore, this method should more accurately reflect the impact of weather variations on the consumption data.

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the months of May to October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal and cooperative customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

The plots also revealed significant changes in average use over time. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average (ARIMA) procedures were used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

ARIMA procedures were developed for the analysis of time series data, i.e., sets of observations generated sequentially in time. This Box-Jenkins approach is based on the assumption that the behavior of a time series is due to one or more identifiable influences. This method recognizes three effects that a particular observation may have on subsequent values in the series:

1. A decaying effect leads to the inclusion of autoregressive (AR) terms;
2. A long-term or permanent effect leads to integrated (I) terms; and,
3. A temporary or limited effect leads to moving average (MA) terms.

Seasonal effects may also be explained by adding additional terms of each type (AR, I, or MA).

The ARIMA procedure models the behavior of a variable that forms an equally spaced time series with no missing values. The mathematical model is written:

$$Z_t = u + Y_i (B) X_{i,t} + q (B)/ f (B) a_t$$

This model expresses the data as a combination of past values of the random shocks and past values of the other series, where:

t indexes time

B is the backshift operator, that is $B (X_t) = X_{t-1}$

Z_t is the original data or a difference of the original data

f(B) is the autoregressive operator, $f(B) = 1 - f_1 B - \ldots - f_1 B^p$

u is the constant term

q(B) is the moving average operator, $q (B) = 1 - q_1 B - \ldots - q_q B^q$

a_t is the independent disturbance, also called the random error

$X_{i,t}$ is the ith input time series

$y_i(B)$ is the transfer function weights for the ith input series (modeled as a ratio of polynomials)

$y_i(B)$ is equal to $w_i (B)/ d_i (B)$, where $w_i (B)$ and $d_i (B)$ are polynomials in B.

The Box-Jenkins approach is most noted for its three-step iterative process of identification, estimation, and diagnostic checking to determine the order of a time series. The autocorrelation and partial autocorrelation functions are used to identify a tentative model for univariate time series. This tentative model is estimated. After the tentative model has been fitted to the data, various checks are performed to see if the model is appropriate. These checks involve analysis of the residual series created by the estimation process and often lead to refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[3] was used in developing the ARIMA models contained herein.

The attractiveness of ARIMA models comes from data requirements. ARIMA models utilize data about past energy use or customers to forecast future energy use or customers. Past history on energy use and customers serves as a proxy for all the measures of factors underlying energy use and customers when other variables were not available. Univariate ARIMA models were used to forecast average use or total usage when weather-related variables did not significantly affect energy use or alternative independent explanatory variables were not available.

Footnotes

1. The 15-year average daily weather "normals" were based on data from 1987 to 2001 published by the National Oceanic and Atmospheric Association.

2. SAS Institute, Inc., SAS/STAT[tm] Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987

3. SAS Institute, Inc., SAS/ETS User's Guide, Version 6, First Edition. Cary, NC: SAS Institute, Inc., 1988.

Electric Sales Assumptions

For short-term forecasting, 31 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, nineteen large industrial customers were individually projected. The residential class was disaggregated into those customers with electric space heating and those without electric space heating and by housing type (single family, multi-family, and mobile homes). Each municipal and cooperative account represents a forecasting group and were also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer nuclear plant outages. Unaccounted for energy is usually about 4.5% of total territorial sales. The monthly allocations for unaccounted for were based on a regression model using normal total degree days for the calendar month and total degree days weighted by cycle billing. Adding company use and unaccounted for to monthly territorial sales produces electric generation requirements.

TABLE 1
Short-Term Forecasting Groups, 2003 – 2004

Class Number	Class Name	Rate/SIC Designation	Comment
		Single Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64
10	Residential Non-Space Heating	Multi Family	67, 68, 69
910	Residential Space Heating	Mobile Homes	Rates 1, 2, 5, 7, 8
20	Commercial Non-Space Heating	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other	Rates 10, 11, 14, 16, 17, 18, 24, 25, 26, 29 60, 62, 64, 67, 68, 69
920	Commercial Space Heating	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 91	Executive, Legislative and General Government (except Finance)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 25 and 26
930	Industrial Space Heating	Rate 9	Small General Service
60	Street Lighting	Rates 3, 9, 13, 17, 25, 26, 29, and 69	
70	Other Public Authority	Rate 3 and 29	
		Rates 65 and 66	
92	Municipal	Rate 60, 61	Four Individual Accounts
97	Cooperative	Rate 60, 61	Four Individual Accounts

Includes small industrial customers from all SIC classifications that were not previously forecasted individually.

Note: Industrial Rate 23 also includes Rate 24. Commercial Rate 24 also includes Rate 23.

TABLE 2

Summary of Methodologies Used To Produce
2003 and 2004 Short range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups Class 910, All Groups Class 20, Rates 9, 12, 20, 22, 24, 99 Class 920, Rate 9 Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99 Class 930, Rate 9 Class 60 Class 70, Rates 65, 66
	Regression	Class 92, All Accounts Class 97, All Accounts
Customers	ARIMA	Class 10, All Groups Class 910, All Groups Class 20, All Rates Class 920, Rate 9 Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91 Class 930, Rate 9 Class 60 Class 70, Rate 3

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long range electric sales forecast for the Company. The long range electric sales forecast was developed for seven classes of service: residential, commercial, industrial, street lighting, other public authorities, municipal and cooperatives. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 90% of total territorial sales. A customer forecast was developed for each major class of service. For the residential class, forecasts were also produced for those customers with electric space heating and for those without electric space heating. They were further disaggregated into housing types of single family, multi-family and mobile homes. In addition, two residential classes and residential street lighting were evaluated separately. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns. The industrial class was disaggregated into two digit SIC code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales was estimated based on total usage in that class of service. The number of residential customers and average usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics which indicate the success of the regression analysis fit were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC STEPWISE, PROC REG, and PROC AUTOREG of SAS were used to estimate all regression models. PROC STEPWISE was used for preliminary model specification and elimination of insignificant variables. PROC REG was used for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic.

Prior to developing the long range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable to obtain a forecasted growth rate for a dependent variable. These forecasted growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.

- One way to incorporate conservation effects on electricity is through real prices, or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.
- The remaining variables to be included in the models for the major classes would come from four categories:
    1. Demographic variables - Population.
    2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
    3. Weather variables - average summer/winter temperature or heating and cooling degree days.
    4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., foreign oil price increases in 1979 and recession versus non-recession years).

Standard statistical procedures (all possible regressions, stepwise regression) were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.
- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with others. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long range electric forecast included the following variables.

Service Area Population
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity
Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc., (formerly DRI-WEFA) and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature or CDD (Average of June, July and August temperature) and average winter temperature or HDD (Average of December (previous year), January and February temperature) were assumed to be equal to the normal values used in the short range forecast.

Peak Demand Forecast

This section describes the procedures used to create the long range summer and winter peak demand forecasts. It also describes the methodology used to forecast monthly peak demands. Development of summer peak demands will be discussed initially, followed by the construction of winter peaks.

Summer Peak Demand

The forecast of summer peak demands was developed with a load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed to derive the territorial peak.

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated from historical data and then used to estimate peak demands from the projected energy consumption among these categories. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted individually. Summing these class, rate, and individual customer demands provided the forecast of summer territorial peak demand. Next, the incremental reductions in demand resulting from the Company's standby generator and interruptible programs were subtracted from the peak demand forecast. This calculation gave the firm summer territorial peak demand, which was used for planning purposes.

Load Factor Development

As mentioned above, load factors are required to calculate KW demands from KWH energy. This can be seen from the following equation, which shows the relationship between annual load factors, energy, and demand:

$$\textit{Load Factor} = \textit{Energy}/(\textit{Demand} \times 8760)$$

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a load factor will usually range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This form of the equation is used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales.

The load factors used for the peak demand forecast were not based on one-hour coincident peaks. Instead, it was determined that use of a 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that all of the summer peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand of the residential and commercial classes depended on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined. Thus, load factors based on peaks occurring at, say, 2PM, would be quite different from those developed for a 5PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand, for say, municipals, was within 2% of the 1-hour coincident peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections.

Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. These projections were utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this forecast.

Derivation of the planning peak required that the impact of demand reduction programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet the firm peak demand, which includes the reductions attributable to such programs.

Winter Peak Demand

To project winter peaks actual winter peak demands were correlated with two primary explanatory variables, total territorial energy and weather during the day of the winter peak's occurrence. Several other dummy variables were also included in the model to account for recessions, two extreme winters, and the higher than average growth experienced on the system over the past decade.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors which cause winter peak demand to change. It should be noted that the winter peak for any given year occurs by definition after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968, while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this variable was measured by the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston. The presence of a weather variable reduces the bias which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the normal value of heating degree-days over the sample period was used. Finally, although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to over 215,000 in 2002, a 10.7% annual growth rate. However, this growth slowed dramatically in the 1990's, so the expectation is that the ratio of summer to winter peaks will change slowly in the future.